STATE OF RHODE ISLAND

PUBLIC UTILITIES COMMISSION

IN RE: THE RHODE ISLAND DISTRIBUTED GENERATION BOARD'S RECOMMENDATIONS FOR THE 2026-2027 RENEWABLE ENERGY GROWTH PROGRAM YEAR	:	DOCKET 25-52-REG

Recommendations for the 2026-2027 Renewable Energy Growth Program Year

DISTRIBUTED-GENERATION BOARD
& OFFICE OF ENERGY RESOURCES

NOVEMBER 21, 2025

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DISTRIBUTED-GENERATION BOARD
REG 2026-2027 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 2026-2027 PY[1] represent the following:

- Proposed (administratively-set) prices for Small Solar I and II renewable energy classes;
- A proposed Megawatt Allocation Plan for the 2026-2027 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 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 17 meeting and are endorsed by the OER.

[1] This report adopts an updated naming convention for program years, reflecting that a single program year spans multiple calendar years. As such, the program year previously referred to as 2026 is now referred to as 2026-2027.

Goals and Objectives

The REG law was amended by the General Assembly in 2023[2]. 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.*[3]

Consistent with such purposes of the amended REG law, the anticipated outcomes for the REG 2026-2027 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).

[2] Available at: http://webserver.rilin.state.ri.us/PublicLaws/law23/law23300.htm
[3] 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 2026-2027 PY.

The DG Board respectfully recommends that the PUC approve new Small Solar I and II ceiling prices (of 31.55 ¢/kWh and 28.65 ¢/kWh, respectively) for the 2026-2027 PY. The DG Board does not recommend revisions to previously approved non-Small Solar ceiling prices. 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 2026-2027 PY.

Table 2 – Recommended Small Solar I and II Ceiling Prices (2026-2027 PYs, ¢/kWh)

Renewable Energy Class	Eligible System Sizes	Tariff Length	Ceiling Price (¢/kWh)
Small Solar I	<=15 kW_{DC}	15 Years	31.55
Small Solar II	>15-25 kW_{DC}	20 Years	28.65

Megawatt Allocation Plan

Consistent with R.I. Gen. Laws § 39-26.6-12(c), the DG Board respectfully recommends the PUC adopt the recommended Megawatt Allocation Plan the REG 2026-2027 PY as shown in Table 3 below. Consistent with the 2025-2026 PY Megawatt Allocation 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#4 to conclude.

Table 3 - Recommended Megawatt Allocation Plan for the *2026-2027 PY*

Renewable Energy Class	Eligible System Sizes	PUC Approved 2025-2026 PY MW Allocation Plan	Recommended 2026-2027 PY (MW_{DC})
Small Solar	<=25 kW_{DC}	9	3
Medium Solar	>25-250 kW_{DC}	7	9
Commercial Solar I	>250-500 kW_{DC}	9.5	8.5
Commercial Solar I (CRDG)	>250-500 kW_{DC}	0.5	0.5
Commercial Solar II	>500 kW-1 MW_{DC}	11.5	8
Commercial Solar II (CRDG)	>500 kW-1 MW_{DC}	1	1
Large Solar I	>1-<5 MW_{DC}	**20**	**25**
Large Solar I (CRDG)	>1-<5 MW_{DC}	5	5
Large Solar II	5 MW-<10 MW_{DC}	**30**	**20**
Large Solar III	10-<15 MW_{DC}	**15**	**15**
Large Solar IV	15-<39 MW_{DC}	0	0
Wind	≤ 5 MW_{AC}	3	3
Wind CRDG	≤ 5 MW_{AC}		
Anaerobic Digestion	≤ 5 MW_{AC}	1	1
Small Scale Hydropower	≤ 5 MW_{AC}		
Total		**112.50**	**94**

Conclusion

After a thorough and transparent development process, the DG Board voted at its November 17, 2025, meeting to recommend the allocation plan and proposed Small Solar I and II ceiling prices for the 2026-2027 PY. The DG Board and OER respectfully request that the PUC consider and approve the recommendations for the REG 2026-2027 PY.

DIRECT TESTIMONY OF TOBIN ARMSTRONG, 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. For the 2026-2027 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 eleven years of experience related to renewable energy policy, and seven 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 2023-2025, 2024-2025, and 2025-2026 ceiling price development process, I provided testimony in Dockets 22-39-REG, 23-44-REG, and 24-50-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: What topics or issues will your testimony pertain to?

A: My testimony will pertain to the ceiling price development process, the recommended ceiling prices, and the recommended Megawatt Allocation Plan. I will specifically address the methodology used by SEA to address ceiling price modeling inputs related to installed cost,

operating cost, and federal tax benefits. I will also discuss the reasonableness of previously-approved non-small solar ceiling prices in light of SEA's revised modeling.

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 2026-2027 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. This year's efforts included a specific focus on the implications of the recently enacted One Big Beautiful Bill Act (OBBBA) on project cost and tax benefit assumptions, including an assessment of impacts for non-small solar projects. 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.

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. CEILING PRICE 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: SEA acts as a joint facilitator of a months-long 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, generating recommended ceiling prices through multiple rounds of analysis.

The process included three presentations to stakeholders and four presentations to the DG Board. At the final presentation, the DG Board discussed and approved OER's proposed recommendations, which are reflected in the Report and Recommendations.

During the process for developing the 2026-2027 program plan, SEA also managed, on OER's behalf, the above-described data- and stakeholder-driven process. SEA's research focused 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. However, given significant changes to federal tax credit eligibility, SEA's research also assessed the reasonableness of previously approved non-small solar ceiling prices.

Q: What were the milestones for engagement with the DG Board and stakeholders during the 2026-2027 PY process?

A: Key milestones in the 2026-2027 program plan development process were as follows:

- July 28, 2025 – Presentation to DG Board regarding implications of OBBBA on ceiling price development process;
- July 30, 2025 – Stakeholder session including SEA presentation of first draft prices for Small Solar I and II;
- August 21, 2025 – First draft of Megawatt Allocation Plan released for public comment via solar stakeholder email;
- August 25, 2025 – Presentation to DG board on updates related to SEA analysis of OBBBA implications for program plan;
- September 17, 2025 - Stakeholder session including SEA presentation of second draft prices for Small Solar I and II, and analysis of OBBBA implications for non-small solar prices;
- September 29, 2025 – Presentation to DG board on SEA findings to date;
- October 15, 2025 – Third draft of Small Solar I and II prices and analysis of OBBBA implications for non-small solar prices released for public comments;
- November 17, 2025 – Presentation to DG board on final recommended program plan.

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

A: Yes. SEA's three presentations are provided as Schedule 2 through Schedule 9, respectively.

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 met with the DPUC on September 2, 2025 regarding the proposed program plan and had numerous email exchanges regarding the evolution of OER's proposal. In addition, OER received numerous sets of comments from the DPUC which were incorporated into the Small Solar ceiling prices and Megawatt Allocation Plan.

B. Cost of Renewable Energy Spreadsheet Tool ("CREST")

Q: Can you please describe the Cost of Renewable Energy Spreadsheet Tool ("CREST") model and how it was used?

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.[4] 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 third draft ceiling prices for all renewable energy classes. This simplified model contains revisions relative to the version of CREST available on the NREL website, providing certain functionality specific to the REG program design.

[4] 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.

C. Stakeholder Engagement Process

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

A: SEA received three responses to the data request and survey from members of the solar industry (which can be found in Schedule 1), and conducted eleven targeted interviews with additional industry members related to the implications of federal changes in law on the REG program. In addition, SEA received multiple rounds of comments from RI Energy and the DPUC, and a single comment from Newport Solar, 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 solar capital and financing expenses from solar industry members, with focus on implications of OBBBA for project cost, financing, and tax credit eligibility. SEA received comments from RI Energy and the DPUC regarding SEA's price calculation methods, analysis in support of the 2026-2027 Megawatt Allocation plan, and OER's proposed program design elements (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.

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 2026-2027 PY recommended ceiling prices for Small Solar I and II take other recent data sources (which are described and linked within Schedule 3, Schedule 6, and Schedule 8) 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 the recommended 2026-2027 Small Solar ceiling prices and the proposed Megawatt Allocation Plan?

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

D. Accounting for Federal Changes in Law

Q: Following the 2025-2026 program plan development process, were there major changes in law at the federal level that could have implications for the REG program?

A: Yes. On July 4, 2025, Public Law 119-21 (H.R. 1) – The One Big, Beautiful Bill Act (OBBBA) was signed into law.

Q: What specific provisions in the OBBBA have potential implications for the REG program?

A: First, Section 70506 terminates the Residential Clean Energy Credit, which provides a tax credit of up to 30% for certain residential clean energy installations to individual tax payers, effective beginning with expenditures made after December 31, 2025. This has significant implications for Small I and Small II REG projects. However, the termination of this credit does not impact leased projects, which remain eligible for the Clean Electric Production Credit (CEPC) and Clean Electricity Investment Credit (CEIC) under Internal Revenue Code Sections 45Y and 48E, as discussed below.

Second, Sections 70512 and 70513 modify and phase out the CEPC and CEIC in 45Y and 48E with regard to solar and wind energy applications. The CEPC and CEIC are the technology-neutral successor tax credits to the Production Tax Credit (PTC) and Investment Tax Credit (ITC); these terms are often still used to refer to the successor credits. Respectively, the

CEPC and CEIC provide a tax credit of up to 1.5 cents per kWh or 30% of eligible upfront project cost, provided they meet certain prevailing wage and registered apprenticeship requirements. Projects may also qualify for the optional "domestic content" and "energy community" bonuses, each worth up to an additional 10%. For the CEPC, these bonuses are multiplicative, but for the CEIC, they are additive.

Specifically, the CEPC and CEIC would no longer apply to wind and solar facilities placed in service after December 31, 2027, except for facilities that begin construction by July 4, 2026. Additionally, facilities that commenced construction after December 31, 2025, with "material assistance" from a "prohibited foreign entity," would be ineligible (commonly known as the Foreign Entity of Concern (FEOC) requirement). A determination of material assistance occurs when a facility fails to meet a "material assistance cost ratio" threshold expressed as *(Total Component Costs – Total Component Costs From Prohibited Foreign Entities) / Total Component Costs*. Prohibited foreign entities include "foreign-controlled entities" (e.g., a government or business unit of or in China, Russia, North Korea, or Iran) and "foreign-influenced entities," in which one or more foreign-controlled entities has a certain ownership or voting interest, a certain level of entity's outstanding debt, or has the power to appoint key executives.

Third, Section 70301 of the bill reinstates, and makes permanent, the option for 100% first-year bonus depreciation for qualified property—which includes commercial renewable energy production systems—acquired and placed in service after January 19, 2025. There is no specific end date for this provision.

Q: Following the passage of the OBBBA, did the U.S. Department of the Treasury issue guidance relevant to tax credit eligibility?

A: Yes. On July 7, 2025, President Donald Trump issued an Executive Order directing the Secretary of the Treasury to issue new guidance on the meaning of "beginning of construction" to "prevent[] the artificial acceleration or manipulation of eligibility and [to] restrict[] the use of broad safe harbors unless a substantial portion of a subject facility has been built."[5] On August 15, the U.S. Department of the Treasury issued said guidance.[6]

Q: What was the content of the Treasury guidance?

A: Under the new guidance, to qualify for the CEPC or CEIC under the "beginning of

[5] https://www.whitehouse.gov/presidential-actions/2025/07/ending-market-distorting-subsidies-for-unreliable-foreign%E2%80%91controlled-energy-sources/
[6] https://www.irs.gov/pub/irs-drop/n-25-42.pdf

construction" threshold, a facility must either (i) demonstrate that it has begun "physical work of a significant nature" either on-site (e.g., excavation of foundations) or off-site (e.g., manufacture of inverters and transformers), or (ii) if it is under 1.5 MW_{AC}, demonstrate that it has incurred at least 5% of capital costs. Notably, work to manufacture a component of a facility that is either in existing inventory or is normally held in inventory by one selling the component does not qualify as off-site work. Additionally, the guidance provided that all facilities must maintain continuous construction to retain tax credit eligibility. However, delays including severe weather, permitting, interconnection, and equipment shipments are exempt from this requirement. Lastly, all facilities must also be constructed within four calendar years after the calendar year in which construction began (known as the IRS' "continuous construction" requirements); after that period, the Treasury will determine whether the facility met this continuous construction requirement according to a "relevant facts and circumstances" standard.

Q: Given these provisions, what specific questions did SEA's research aim to address regarding the implications of the OBBBA for the REG program's 2026-2027 PY?

A: SEA's research focused on assessing the following issues: 1) the ability to qualify projects of various scales for CEIC safe harbor; 2) implications for the expiration of the Residential Clean Energy Credit; 3) the impact of Treasury guidance regarding the definition of "begin construction; 4) the potential for new financing structures/products likely to emerge post-OBBBA; 5) the ability to leverage 100% bonus depreciation for projects losing ITC eligibility and/or projects retaining ITC eligibility; and 6) the impact of FEOC requirements on project cost and timelines, including interaction with the ITC domestic content bonus.[7]

Q: How did SEA's research process address the potential implications of the OBBBA for the REG program?

A: SEA conducted targeted interviews with eleven developers and financiers to better assess the aforementioned issue's implications for the 2026-2027 program plan. In addition, SEA conducted broader desktop research on publicly available assessments of these issues.

Q: How did SEA approach the program plan development process with respect to non-small solar projects, given that such projects are subject to previously approved ceiling prices through the end of PY 2026-2027?

[7] Certain research questions (e.g., post-OBBBA financing structures) became less relevant following the release of the August 15 Treasury guidance, given that the guidance suggested a significant portion of projects in the 2026-2027 PY could qualify for the CEIC. However, such research questions will become much more relevant for future program years.

A: The PUC Written Order in Docket 23-44-REG specifies that changes to previously approved ceiling prices in the 2024-2026 program plan will require the requesting party provide evidence the established prices will not result in the statutorily "reasonable rate of return." To assess the impact of OBBBA on the reasonableness of return under previously approved ceiling prices, SEA modeled updated ceiling prices for non-small solar renewable energy classes to understand the relative impact of updated project costs and financing inputs on calculated ceiling prices. SEA used these results to allow for informed stakeholder feedback and decision-making regarding the reasonableness of return under previously approved ceiling prices.

Q: Did the PUC provide directives related to SEA's research regarding potential updated non-small solar ceiling prices?

A: Yes. As ordered by the PUC in Docket 25-13-REG, in exploring updated ceiling prices for non-small solar, SEA considered the "totality of costs" impacting such classes beyond the incremental impacts of FEOC requirements alone.

Q: Given the PUC's directive to consider the "totality" of costs, with regard to non-small solar ceiling price analysis, what issues unrelated to the OBBBA provisions discussed above did SEA's research consider?

A: For non-Small Scale solar, SEA's non OBBBA-related research focused on updating installed cost and interest rate inputs. These inputs were prioritized as they both have the largest relative impact on ceiling prices and are expected to be subject to the most variance year to year. In addition, SEA conducted research resulting in an update to its tax equity target rate of return inputs for all renewable energy classes in its third draft analysis.

III. RECOMMENDED CEILING PRICES

A. Federal Tax Benefits Methodology

Q: What issues related to federal tax benefits did SEA consider in its program plan development process?

A: SEA's research considered the implications of the expiration of the Residential Clean Energy Credit in 2026 and the ability for projects of various scales to qualify for the CEIC in the 2026-2027 PY by utilizing one of the safe harbor routes (commenced construction or commercial operation). This research included consideration of the impact of Treasury guidance regarding the

definition of "begin construction." In addition, SEA's research considered the ability for projects to leverage 100% bonus depreciation, for projects both losing and retaining ITC eligibility.

Q: What renewable energy classes are anticipated to be impacted by the expiration of the Residential Clean Energy Credit in 2026?

A: The expiration of the Residential Clean Energy Credit is expected to primarily impact the Small Solar I renewable energy class, given that residential-scale projects are typically under 15 kW and that the Credit is only available to individual homeowners who install and own qualified clean energy systems on their residence and have the tax appetite to take advantage of a tax credit. Thus, SEA assumes that no host-owned Small Solar I projects will be able to leverage the Residential Clean Energy Credit in the 2026-2027 PY.

Q: Is it possible for Small Solar I projects to still qualify for federal tax benefits in the 2026-2027 PY?

A: Yes. Although SEA understands it to be impossible for Small Solar I to qualify for the Residential Clean Energy Credit in the 2026-2027 PY, Small Solar I projects that are developed under a third-party ownership (TPO) model can still qualify for the CEIC, provided they meet applicable safe harbor provisions. In addition, Small Solar I projects that are sited on a commercial property can also qualify for the CEIC. Given the relatively shorter period from project origination to commercial operation, SEA determined that it was highly likely that such Small Solar I projects participating in the 2026-2027 PY could achieve commercial operation prior to the December 31, 2027 deadline required to safe harbor CEIC eligibility.

Q: Given historical enrollment patterns, what ownership model is more common for Small Solar I in the REG program?

A: An analysis of RI Energy's enrollment data shows that, historically, Small Solar I has been dominated by host-owned facilities (over 95% of projects in the last five program years), which would no longer be eligible for federal tax benefits in the 2026-2027 PY.

Q: In prior program years, what ownership model was assumed when setting Small Solar I prices?

A: In previous program years' development process, Small Solar I has been modeled as a host-owned facility, consistent with program enrollment trends.

Q: Given this, how did OER approach designing a price applicable to Small Solar I for the 2026-2027 PY?

A: Given that it is highly uncertain if and when the market will adapt to provide TPO offerings under the REG program, OER had to weigh the potential costs of interrupting support for the host-owned market with the potential benefits to ratepayers from designing prices based on projects that can leverage federal tax benefits. Ultimately, OER determined that it was prudent to model Small Solar I prices based as a TPO system leveraging the 30% CEIC. This decision resulted in a reduced price relative to an alternative in which the Small Solar I price continued to be modeled as host-owned.

Q: Did OER explore alternatives to this approach throughout the program development process?

A: Yes. Throughout the 2026-2027 PY development process, OER explored a range of options for the design of Small Solar I prices. First draft prices modeled Small Solar I as a host-owned system unable to leverage federal tax benefits. Second draft prices provided differentiated pricing for Small Solar I TPO and Small Solar I host-owned. Third and final draft prices provided a single price modeled based on a TPO project.

Q: Did stakeholder feedback inform OER's proposed approach to Small Solar I pricing?

A: Yes. Both the DPUC and RI Energy expressed concern regarding offering a price applicable to host-owned projects unable to leverage federal tax benefits during a period in which lower-cost TPO projects could leverage such benefits. These comments, in addition to general concerns regarding limiting the cost of the REG program, informed OER's adopted approach.

Q: With respect to the ability for non-Small Solar I projects to qualify for CEIC in the 2026-2027 PY, what were SEA's findings?

A: SEA's research concluded that it is reasonable to assume that a significant share of Small Solar II through Large Solar IV projects can qualify for the CEIC in the 2026-2027 PY.

Q: What informed this conclusion?

A: A majority of respondents to SEA's information interviews on the impact of OBBBA reported that qualification for either of the ITC safe harbor pathways was feasible for PY 2026-2027 projects. For projects under 1 MW, a majority of respondents expected that it would be feasible to achieve commercial operation prior to the December 31, 2027 safe harbor cutoff. For projects over 1 MW that are more likely to be subject to interconnection study, a majority of respondents suggested that it would be feasible to begin physical work off-site prior to obtaining a REG Certificate of Eligibility (COE), allowing for qualification via the commenced

construction safe harbor.

Q: Given this conclusion, what was SEA's modeling approach with respect to federal tax benefits?

A: SEA continued to assume that Small Solar II through Large Solar IV could retain a 30% CEIC in the 2026-2027 PY. Although it is likely that certain projects will not be able to meet safe harbor provisions necessary to qualify, OER determined that the benefits of capturing cost savings made possible by leveraging the CEIC in ceiling prices outweighed the potential risks to program success. This is especially relevant given that the 2026-2027 PY is the last year in which projects can reasonably qualify for the CEIC. Given this, ensuring such low-cost projects are selected in the 2026-2027 PY is a unique opportunity to capture such benefits before they expire.

Q: Does SEA expect that assumptions regarding CEIC eligibility will need to be updated in future year program plans?

A: Yes. SEA's research suggests that the 2026-2027 PY is the last year in which a significant number of projects in the REG program's renewable energy classes can reasonably qualify for the CEIC. As such, SEA's expectation is that ceiling prices for certain renewable energy classes in the 2027-2028 program plan will need to account for new financing structures that will emerge absent federal investment tax credit support.

Q: Did SEA consider changes to assumptions regarding bonus depreciation for solar projects during the program development process?

A: Yes. SEA considered changes to its assumptions regarding bonus depreciation as a component of its data request and survey and informational interviews, given that OBBBA makes 100% bonus depreciation permanently available. In addition, SEA conducted general market research through its broader market analytics consulting engagements to determine if factors influencing the ability for projects to claim bonus depreciation have changed.

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

A: No, we did not.

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

A: Developers and financiers engaged by SEA continued to report, consistent with SEA's findings in prior PYs, that most tax equity investors who are able to claim an investment credit

did not utilize bonus depreciation. Respondents reported that tax equity investors generally avoided bonus depreciation to reduce risk by distributing their tax-driven investments over a higher volume of projects. Utilizing both bonus depreciation and an investment credit, by contrast, requires significant tax appetite in year one to fully utilize such benefits, and reduces the number of projects that an investor could spread tax appetite across in a given year. In addition, SEA's understanding, based on conversations with financiers, is that utilizing both bonus depreciation and an investment credit can produce problematic outcomes if tax benefits significantly exceed tax liability through maximization of net operating losses in Year 1.

Q. Why might maximizing net operating losses in Year 1 be problematic, and how might this inhibit the closure of tax equity deals?

A. SEA's understanding, based on conversations with financiers, is that maximizing net operating losses in Year 1 can be problematic for a number of reasons. First, carrying forward tax benefits beyond Year 1 reduces the ability to utilize tax equity benefits efficiently, reducing their value from a net present value perspective. Second, net operating losses carried forward are subject to restrictions that prevent their application to offset full tax liability in future years, potentially further extending the time over which benefits would be utilized. Third, significant losses can have implications for the IRS' treatment of capital accounts in tax equity deals. Specifically, it is SEA's understanding that, if a tax equity investment partner receives sufficiently large losses, Internal Revenue Code section 704(b) requires that the investor either accept a binding legal obligation to repay that deficit (known as a Deficit Restoration Obligation) or that the partnership must restructure the allocations of tax benefits.[8] All of these considerations create planning risk and contribute to tax equity investors' preference against the utilization of 100% bonus depreciation in combination with the CEIC.

Q: Given these considerations, what was SEA's adopted approach?

A: Given the above considerations, SEA continued to assume a five-year schedule of the Modified Accelerated Cost Recovery System (MACRS) for depreciation, as respondents continued to report that such a schedule is the norm in applicable tax equity deals. Nevertheless, respondents also reported that, for projects losing CEIC eligibility, new financial products/structures utilizing 100% bonus depreciation are likely to emerge, but that such offerings have yet to be developed (and are more likely to be available in future PYs).

Q: Given this feedback, it fair to say that this is the final year in which bonus depreciation will

[8] See 26 U.S.C. § 704(b)

not generally be included for the ceiling prices?

A: Yes, that is correct. When CEIC eligibility disappears for projects with CODs that fall after the cutoff for projects that begin construction no later than July 4, 2026, such projects will need to be developed under more traditional project financing structures that predominantly focus on free cash flow over the distribution of non-depreciation tax benefits.

B. Installed Cost Methodology

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. Through these sources, SEA collects installed cost data applicable to projects in 2024 and 2025. Consistent with the 2025-2026 ceiling price development process and given the 2025-2026 PY'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.

Next, 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 Schedule 3) to transform the 2024 and 2025 installed cost figures derived via the methods discussed above into forecasted 2026 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 Producer Price Index).

This process establishes a "baseline" installed cost input. SEA then makes certain adjustments, where appropriate, to reflect RI-specific costs and/or costs assumed to not yet be reflected in the historical data. The installed cost inputs, by resource class, resulting from these methods, as compared to the installed cost inputs adopted during the 2025-2026 PY ceiling price development process, are provided in Appendix A of Schedule 8.

Q: Overall, how did the Small Solar installed cost inputs derived through the above process compare to those adopted in the modeling informing the 2025-2026 PY plan?

A: The installed cost inputs derived through the above process resulted in significant reductions to the Small Solar I and II installed costs, due to an observed decline in median

installed costs from regional databases in the last two years (see Slide 23 of Schedule 6 for details).

Q: What adjustments were made to the Small Solar I and II installed cost inputs derived through this process?

A: For Small Solar I and II, SEA made two adjustments to the installed cost inputs derived through the process discussed in the previous answer to capture incremental labor costs and costs associated with meeting FEOC requirements imposed by OBBBA 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 2024. To address this, SEA adopted the incremental $30/kW to reflect such costs derived in the 2025-2026 ceiling price development process. This incremental cost was not applied to RI-specific data points in 2025, assuming that such data would already contain costs associated with meeting such labor requirements.

Q: Why were adjustments to installed cost data relating to FEOC requirements necessary?

A: As discussed above, OBBBA subjects projects qualifying for the CEIC to incremental FEOC requirements. SEA's research suggests that such requirements impose additional costs on projects that would not be reflected in historical installed cost data. Specifically, SEA's research suggests that incremental FEOC costs are typically $50-200/kW, with the spread driven by supplier choices, risk tolerance, and project scale.

This cost reflects several cost drivers imposed by FEOC requirements. First, many developers and renewable energy supply chains are heavily reliant on equipment sourced from China, a "prohibited foreign entity." Equipment re-sourcing is expected to impose incremental

costs, as heightened demand for FEOC-compliant equipment has put pressure on compliant supply. Many of the developers SEA engaged for its research were in the process of or already had entered into contracts to secure FEOC-compliant supply.

Next, FEOC requirements create additional legal and administrative hurdles, which are also a cost driver. For instance, projects seeking CEIC qualification may be subject to FEOC audits from investors and additional contracting and legal complexity to navigate FEOC-related risk. SEA understands that certain developers may pursue, or be required by investors to obtain, FEOC insurance to address such risk.

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

A: SEA adopted an incremental cost of $150/kW applicable to Small Solar I and II to reflect expected FEOC-related costs in the 2026-2027 PY. For illustrative ceiling price analysis for non-small solar, SEA adopted an incremental cost of $150/kW for Medium Solar through Commercial Solar II, an incremental cost of $100/kW for Large Solar I and Wind, and an incremental cost of $50/kW for Large Solar II through IV. SEA assumes that Hydro and AD will not be impacted by FEOC, given there is less reliance on Chinese manufacturers in those sectors relative to solar.

Q: Did SEA consider interactions between FEOC requirements and the requirements necessary to secure a domestic content bonus?

A: Yes. In SEA's interviews with developers and financiers, SEA explored the ability for projects meeting FEOC requirements to offset all or some of the incremental costs associated with FEOC requirements with the domestic content bonus.

Q: What were SEA's findings with respect to the ability to leverage the domestic content bonus to offset FEOC-related costs?

A: Market participants reported that they treat domestic content as a separate business case that may or may not be economically viable depending on project specifics. SEA's understanding is that, although certain suppliers may be both FEOC and domestic content compliant, this is very case-dependent and inappropriate to assume for a typical project. In addition, several sources said the domestic content bonus tends to be a "wash" after considering the incremental costs necessary to secure it. As such, these sources reported that efforts to obtain domestic content are unlikely to meaningfully offset FEOC-related costs in most cases.

Q: Did OER receive comments regarding its approach to modeling FEOC costs?

A: Yes. In response to the third draft of prices, RI Energy argued that SEA's incorporation

of FEOC costs into proposed prices was premature and inconsistent with past practice. In doing so, RI Energy argued that, in prior PYs, SEA cited the unavailability of Treasury guidance as an impediment to factoring CEIC bonus and transferability into ceiling price assumptions, and noted that FEOC provisions are subject to forthcoming Treasury guidance. As such, RI Energy argued it is premature to incorporate any FEOC-related costs into ceiling prices until such guidance is issued.

Q: Does OER agree with RI Energy's characterization?

A: No. In the period referenced in RI Energy's comments, there was significant uncertainty regarding if IRA transferability provisions would meaningfully lower project financing costs. As such, ITC bonus and transferability provisions did not have realized cost reductions for projects in development at the time research was being conducted. If SEA were to apply adjustments to reflect cost reductions from such provisions, it would have been entirely speculative and thus SEA deemed such adjustments to be premature until guidance was issued.

In the case of FEOC costs, SEA's research indicated that developers are currently experiencing cost increases as a result of FEOC provisions, given the risk introduced by such requirements, the need to proactively mitigate such risks in light of ITC safe harbor deadlines, and the requirements of investors. Given this, SEA determined that it was important to model such costs to ensure that incentives could support development in the 2026-2027 PY, especially since the success of such projects will maximize the pool of program participants able to retain the ITC prior to its expiration, thereby providing low-cost supply relative to SEA's expectations for post-ITC pricing. In contrast, the availability of transferability or CEIC bonus provisions alone did not reduce the cost of projects in development at the time SEA was conducting research in prior PYs, given that investors and developers could not plan to utilize such provisions, or justify such assumptions to investors, until it was clarified if and how projects could utilize such provisions

Lastly, Treasury guidance on FEOC provisions is not required to be published until December 31, 2026. As such, taking RI Energy's approach and waiting until guidance is issued would mean failing to account for such guidance for the 2026-2027 PY, which would fall short of the Renewable Energy Growth Act's requirement that the ceiling prices reflect a cost-based analysis.

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 the utilization of median costs, instead of the average of median and 75th percentile costs, be applied in the calculation of non-small solar ceiling prices.

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

A: No. In order to ensure that the benefits of a three-year program plan can be realized, it is important to provide a predictable scope of revisions that could be made to already-approved ceiling prices. Whereas FEOC costs represent a clear, objective change in law that imposes additional costs on projects not contemplated during the three-year program plan development process, the decision to move to a different quartile of cost when setting ceiling prices is ultimately a policy decision. As such, SEA views it as most appropriate to re-evaluate such practices at the start of the next three-year program plan. Lastly, OER ultimately chose not to pursue updated ceiling prices for non-small solar, making such considerations moot.

C. 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 2025-2026 PY development process?

A: Yes. Given the decision to model Small Solar I as a TPO system, it was necessary to model the operating cost associated with providing the host a discount on their energy bill in exchange for leasing their rooftop. These costs were not previously modeled, given that the 2025-2026 PY development process assumed a host-owned Small Solar I project in CREST modeling.

Q: Why is it necessary to model costs associated with subscriber bill discounts for TPO Small Solar I projects?

A: Under any TPO arrangement, the host requires some form of compensation to incentivize the leasing of their rooftop space for the installation of solar by a third party. For larger-scale renewable energy classes, SEA models that compensation as an annual lease payment in CREST. However, given that Small Solar I was previously modeled as host-owned, it did not have a lease payment modeled. Given this, absent any adjustments to CREST, the modeled price would not provide appropriate headroom to compensate customers to participate in a TPO offering while still allowing the realization of target returns on investment for equity and tax equity sponsors.

Q: Why did SEA model costs associated with subscriber bill discounts rather than an annual rooftop lease payment?

A: For residential customers in TPO markets, the incentive for participation in a TPO

arrangement is often a discount on the host's retail energy bill, rather than a flat lease payment, which is more common for commercial and industrial customers. Given this, in order to model costs that are representative of a typical TPO offering in the region, SEA chose to model such costs as a percentage of the host's retail rate.

Q: How did SEA calculate costs associated with subscriber bill discounts for TPO Small Solar I projects?

A: Subscriber bill discount costs are typically a function of the retail rate the host is subject to and the percentage discount off that rate offered by the third party in exchange for leasing the host's rooftop. To forecast retail rates, SEA utilized the trailing 12-month average of RI Energy's A-16 retail rate as a starting point. This starting point was then inflated using the Energy Information Administration's 2025 Annual Energy Outlook's forecast of Northeast residential retail rates under the reference case. SEA then assumed a 15% discount applied to such rates, based on SEA's understanding that discounts in the range of 10-20% are typical in other third-party markets in neighboring states.[9] The resulting $/kWh cost was then applied to the forecasted production of the project.

Subscriber bill discounts were applied for the entire life of the project. However, consistent with the treatment for post-tariff revenue, post-tariff costs associated with subscriber bill discounts were discounted by 40%.

Q: Did SEA receive comments from stakeholders recommending a revision in Small Solar I and II operating cost assumptions, or regarding the subscriber discount costs modeled?

A: No.

D. Post-Tariff Revenue Methodology

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

A: Consistent with the ceiling prices selected by the Commission for the 2025-2026 PY, SEA assumes that REG facilities, post-tariff, would be entitled to compensation for production at the applicable net metering rate. To reflect this, SEA incorporated a discounted post-tariff

[9] An assumed discount of 15% was also adopted by SEA in a stakeholder process informing incentives for the Massachusetts SMART program. In addition, this discount value was substantiated by Sunrun's August 2025 investor presentation, which reports typical discounts in the range of 5-25% (see https://d1io3yog0oux5.cloudfront.net/_5b648a26605222a1d773260c480b608a/sunrun/db/395/4088/pdf/Sunrun+Investor+Presentation+-+August+2025.pdf)

revenue stream into the CREST model starting after the end of the tariff term and continuing through the end of the project's useful life, provided that such discounted post-tariff revenue could cover project operational costs (e.g., was not resulting in losses that would increase the calculated ceiling price) post-tariff. This revenue stream was based on a forecast of the applicable net metering rate, with a 40% discount applied to reflect the uncertainty regarding program availability and the applicable rate at the end of the tariff term and a further 20% discount applied to reflect provisions *in HB 5853 / SB 684, An Act Relating To Public Utilities And Carriers - Net Metering* that provides virtual net metering credits at 80% of the full net metering rate.

Q: Did SEA make adjustments to its approach to modeling post-tariff revenue relative to the prior PY's approach?

A: Yes. To derive a forecast of net metering revenue, SEA shifted from utilizing an internal forecast of RI Energy's A-16 and C-06 rates to a more transparent, reproducible approach leveraging the Energy Information Administration's 2025 Annual Energy Outlook's forecast of Northeast residential retail rates under the reference case. Specifically, SEA utilized the trailing 12-month average of RI Energy's A-16 and C-06 rates as a starting point and then inflated such values using the forecast provided by the 2025 Annual Energy Outlook.

Q: Did stakeholders provide comments related to SEA's approach to modeling post-tariff revenue?

A: Yes. RI Energy provided comments recommending that SEA update the assumed value of RECs post-tariff based on the REC forecasts provided in the 2024 Avoided Energy Supply Cost (AESC) study. In addition, RI Energy argued that it was inappropriate to apply a 20% discount reflecting the provisions of HB 5853 / SB 684 to Small Solar I and II post-tariff revenue, given that HB 5853 / SB 684 applies to "off-site solar installations." Lastly, RI Energy and the DPUC recommended that SEA remove the 40% discount applied to post-tariff revenue to reflect the uncertainty regarding program availability and the applicable rate at the end of the tariff term, arguing that target equity returns assume some level of risk and that the forecasted retail rates provided by the Annual Energy Outlook account for uncertainty. Please see Schedule 10 for a copy of all such comments.

Q: Did SEA make changes to its approach to address RI Energy's recommendations regarding post-tariff REC revenue?

A: Yes. Previously, SEA modeled a flat value of $5/REC post-tariff given significant

uncertainty regarding the supply/demand dynamics of long-term REC markets. However, given the general shift towards scarcity in Class I markets, SEA determined it was appropriate to update such assumptions in line with the values recommended by RI Energy. As such, SEA adopted post-tariff REC revenue based on the forecasted 2038 RI Class I value of $31.04/REC provided by the 2024 AESC.[10] However, it is important to discount to reflect risk and uncertainty from an investor's perspective. As such, the AESC-derived REC forecast was discounted by 40%, consistent with SEA's treatment of post-tariff energy revenue.[11]

Q: Did SEA make changes to its approach to address RI Energy's recommendations regarding the applicability of net metering discounts reflecting HB 5853 / SB 684 to Small Solar I and II?

A: Yes. Upon review of the statute SEA agrees that application of the 20% discount to net metering revenue for Small Solar I and II is not supported by statute, as projects subject to reduced rates must be "ground-mounted." As such, SEA removed this discount from the calculation of post-tariff revenue for projects under 1 MW.

Q: Did SEA make changes to its approach to address RI Energy and the DPUC's recommendations regarding the applicability of the 40% discount post-tariff energy revenue?

A: No. SEA determined that its prior research findings regarding appropriate discounts and the need to discount post-tariff revenue to capture risk and uncertainty from an investor perspective still apply. Although investors can form a reasonable view of long-term outcomes for retail rates, there is substantial policy risk that net metering in its current form will not exist in 15-20 years. In addition, future retail rates and rate structures (e.g., the share of revenue collected on a volumetric, per kWh basis) are subject to significant uncertainty, compounding this risk. Specifically, SEA's prior research suggests that debt providers do not value post-tariff revenue (since the term of the debt they issue is always shorter than the duration of tariff compensation), and equity investors heavily discount post-tariff revenue as a standard practice, substantiating the reasonableness of a 40% discount.

[10] 2038 is the last year provided in the AESC. Values in the AESC are presented in real dollars, and were translated to nominal dollars using the AESC's assumed long-term inflation rate of 2.25%.
[11] In its comments, RI Energy opposed the application of the 40% discount to REC revenue. This issue is discussed below.

E. Reasonableness of Previously Approved Non-Small Solar Prices

Q: Did SEA's analysis assess the net impact of the changes discussed above on non-solar renewable energy classes?

A: Yes. To assess the impact of OBBBA on the reasonableness of investor return under previously-approved ceiling prices, SEA modeled updated ceiling prices for non-small solar renewable energy classes. SEA used these results to allow for informed stakeholder feedback and decision-making regarding the reasonableness of return under previously-approved ceiling prices.

Q: What were SEA's findings regarding updated revenue requirements for non-small solar renewable energy classes?

A: SEA's analysis revealed that the calculated ceiling price for non-small solar renewable energy classes was generally higher than the previously-approved ceiling prices for PY 2026-2027. The relative increase between previously-approved ceiling prices and updated prices ranged from under 2% in the case of Large Solar classes, to as high as 8.9% in the case of Medium Solar, with Commercial Solar at approximately 4% (see Schedule 8, slide 18 for complete details). As a result, a project with identical cost, financing, and performance inputs to those modeled by SEA subject to the previously-approved ceiling prices would not achieve the target rate of return assumed by SEA.

Q: Given this analysis, did OER determine that the previously-approved ceiling prices would not result in a reasonable rate of return?

A: No. OER determined that the previously approved ceiling prices would result in a reasonable rate of return for a sufficiently large segment of the market.

Q: What informed this conclusion?

A: This conclusion was informed by sensitivity analysis conducted by SEA, which explored under what circumstances the previously-approved ceiling prices would be workable for projects given the updated cost, finance, and performance inputs derived through the 2026-2027 PY process. SEA's sensitivity analysis (presented on slide 20 of Schedule 8), demonstrated that, for a majority of renewable energy classes, projects with median installed cost could meet target returns under the previously-approved ceiling prices. Given this, OER determined that, although the provisions of the OBBBA are likely to limit the number of projects that are economical under the previously-approved ceiling prices, a sufficiently large segment of the market should be able to realize a reasonable rate of return under such prices. In addition, OER is unaware of any party

that has petitioned the Commission arguing that such prices are unreasonable under the current market and federal tax provisions.

Q: Does OER and the DG Board recommend that the previously approved prices remain in effect, without further modification?

A: Yes.

Q: Given the updated Small Solar I and II prices being proposed, are there instances in which a larger renewable energy class is subject to a higher price than a smaller class?

A: Yes. The Medium Solar price of 31.35 cents/kWh previously approved in Docket 23-44-REG is larger than the proposed Small Solar II price of 28.85 cents/kWh.

Q: Has the Commission adjusted recommended prices in prior PYs to ensure that the approved prices conform to economies of scale?

A: Yes. In the Commission's written order in Docket 23-44-REG, the Commission found that "ceiling prices for each size class should not be higher than the price for lower size classes." In doing so, the Commission made several adjustments to recommended prices, including setting the Medium Solar price equal to the recommended Small Solar II price.

Q: Did any stakeholders comment on this issue during the 2026-2027 PY development process?

A: Yes. In its comments on the second draft ceiling prices, the DPUC recommended that the recommended prices be adjusted to conform to economies of scale (see Schedule 10).

Q: Did the DPUC recommend any alternative inputs for the Medium Solar price calculation that would produce results in line with its recommendations?

A: No.

Q: Does OER and the DG Board recommend that the Commission revise the 2026-2027 PY Medium Solar Ceiling Price to be equal to the price for Small Solar II?

A: No.

Q: What are OER's concerns with making such an adjustment?

A: OER has several concerns with adjusting the previously-approved ceiling price to be equal to the Small Solar II price.

First, OER maintains that the ceiling price development process should be data-driven, with recommended pricing resulting from bottom-up CREST modeling performed by experts.

Medium Solar is subject to certain categories of cost that do not typically apply to Small Solar II, including the cost of insurance, project management, land lease, and meter relocation costs. These costs are real, quantifiable, and have been substantiated by stakeholder feedback in recent years' program development processes. As such, OER believes the prices resulting from SEA's analysis reflect real dynamics in the economics of renewable energy classes that should be reflected in program pricing.

Second, the calculated prices for either class represent fundamentally different policy parameters, given that the Medium Solar price is a ceiling price, whereas the Small Solar II price is an administratively set price. Given this, the Medium Solar price is derived by taking an average of the median and 75th percentile costs from installed cost databases, whereas the Small Solar II price is derived from median prices alone. In other words, OER's recommended prices include greater pricing headroom for classes subject to competitive bidding to allow for healthy competition to emerge.

Third, the previously approved Medium Solar price has already been adjusted downward by the Commission relative to the revenue requirement calculated by SEA in the Docket 23-44-REG proceeding. Given this, SEA's updated analysis suggests that, of all renewable classes, Medium Solar's previously approved prices are the farthest from the updated calculations taking into account current-day installed costs, financing inputs, and the implications of OBBBA (namely, FEOC costs). As such, it is SEA's expectation that only extremely low-cost Medium Solar projects will be able to bid under the previously approved prices, and it is likely a higher ratio of those projects will fail to reach commercial operation. Thus, further reductions in the ceiling price may result in poor program performance and a lack of competition in this class.

Fourth, market participants have reported that setting a three-year strip of ceiling prices has been invaluable to inform development activity and provide stable pricing signals. Although OER recognizes that, in certain instances, changes to already-approved prices may be necessary, it is important to maintain a clear, objective framework when such changes would be appropriate such as a change in law or a significant market development. In addition, revisions to pricing should be directionally consistent with cost trends to maintain confidence and predictability in the program's pricing from a participant's perspective. In the instant case, SEA's analysis has demonstrated that net revenue requirements for Medium Solar projects have increased relative to the analysis conducted informing the already-approved Medium Solar price. OER is concerned that reducing the Medium Solar price in this same period would erode the market's confidence in already-approved prices, and the value of a three-year program plan more generally.

Finally, OER is concerned that, given that the 2026-2027 PY represents a unique opportunity to enroll low-cost projects eligible for federal investment credits, adjustments aimed at reducing short-term costs could prevent the program from enrolling such low-cost projects. SEA's expectation is that pricing in future PYs will have to account for the elimination of such investment credits.

F. Recommended Classes and Prices

Q: What are the recommended Small Solar classes, modeled proxy system sizes, tariff terms and ceiling prices for the 2026-2027 PY?

A: The recommended Small Solar renewable energy classes, modeled proxy system sizes, tariff terms, and ceiling prices for the 2026-2027 PY are shown in SEA Table 1 below and are unchanged from those approved by the PUC in Docket 23-44-REG with the exception of Small Solar and II.

SEA Table 1 - Recommended 2026-2027 PY Renewable Energy Classes, Eligible and Modeled System Sizes, Tariff Terms, and Ceiling Prices for Small Solar I and II.

Renewable Energy Class	Eligible Size Range	Modeled Size	Tariff Term	Approved 2025-2026 PY	Recommended 2026-2027 PY
Small Solar I	≤15 kW_{DC}	5.8 kW	15 Years	**33.85**	**31.55**
Small Solar II	>15-25 kW_{DC}	25 kW	20 Years	**32.35**	**28.65**

Q: Does SEA believe that the recommended Small Solar ceiling prices for the 2026-2027 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 statute.

Q: Will SEA, as it has in prior years, make appropriate adjustments to the ceiling prices prior to April 1, 2026, if there are intervening changes in federal tax, trade or other policies that affect the economics of REG-eligible projects?

A: Yes. It is SEA's understanding that it is possible that certain changes to federal tax policy and/or trade tariffs could be made prior to the start of the 2026-2027 PY. SEA plans to work closely with OER and the DG Board to track such changes and their potential impact on the 2026-2027 PY program plan and exercise discretion regarding if revisions to the proposed prices are necessary.

Q: Is OER recommending any revisions to previously approved ceiling prices for non-Small Solar renewable energy classes?

A: No.

IV. RECOMMENDED 2026-2027 PROGRAM YEAR MEGAWATT ALLOCATION PLAN

A. Analysis in Support of Megawatt Allocation Plan for 2026-2027 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. OER also made certain other adjustments to the allocation for renewable energy classes less than 1 MW, discussed in detail below, to limit costs to ratepayers.

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 2026-2027 PY, with consideration given to the likelihood a project could bid into REG 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 pivot and bid

into the REG Open Enrollments.

Q: What scales of project did SEA's analysis of interconnection queue data focus on?

A: Similar to the approach utilized during the development of the recommended 2025-2026 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 must extensively analyze them. As such, an analysis of the queue provides valuable insight into the potential pool of eligible bidders for such projects; 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: For Large Solar I through IV, how did SEA estimate the total capacity of projects that could qualify for the 2026-2027 PY?

A: In coordination with RI Energy, SEA developed assumptions regarding the percentage of Large Solar I through IV projects at each stage of the interconnection process that would qualify for the 2026-2027 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 2026-2027 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 and their ability and likeliness to qualify for the 2026-2027 PY, which resulted in further capacity being excluded from consideration.

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 2026-2027 PY?

A: Yes. A summary of this accounting by size bin is contained in **SEA Table 2.**

SEA Table 2 - Total Capacity (MW_{DC}) of Solar Projects Likely to be Eligible for REG 2026-2027 PY by Interconnection (IC) Process Milestone and Size Bin, Probability-Derated

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

Q: Are there other aspects of the proposed Megawatt Allocation Plan that are designed to maximize healthy competition?

A: Yes. Consistent with the approach approved by the Commission in Docket 24-50-REG, 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 2026-2027 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.

Q: Is OER and the DG Board proposing a Plan A / Plan B Megawatt Allocation Plan similar to the approach approved in Docket 25-50-REG? Why or why not?

A: No. OER and the DG Board are proposing a single Megawatt Allocation Plan. In PY 2025-2026, a Plan A / Plan B Megawatt Allocation Plan was necessary, given that a significant portion of potentially eligible capacity was under study in ASO#3 and the timing of ASO#3's completion prior to the third Open Enrollment was uncertain. In the 2026-2027 PY, SEA's analysis suggested that there is sufficient capacity from projects in ASO#3 and ASO#3b, and from projects not implicated by ASO studies, to support a Megawatt Allocation Plan at a similar scale to the Plan A Megawatt Allocation Plan in PY 2025-2026.

Q: For Small Solar I through Commercial Solar II, did OER adjust the proposed Megawatt Allocation Plan relative to the 2025-2026 PY plan?

A: Yes. The primary changes proposed by OER include reducing the total allocation for renewable energy classes under 1 MW to the statutory minimum of 30 MW and a re-allocation of capacity from Small Solar I and II to larger classes subject to competitive bidding. Both of these revisions were recommended, given limited program uptake of Small Solar I and II in recent PYs and with the aim of limiting costs to ratepayers.

Q: Did SEA, on behalf of OER, receive feedback from stakeholders during the 2026-2027 PY Megawatt Allocation Plan development process?

A: Yes. RI Energy requested clarification regarding how SEA derived the recommended 25 MW allocation for Large Solar I. In doing so, RI Energy argued that the availability of projects to support such an allocation is contingent on the ASO#4 being completed prior to the third Open Enrollment.

Q: Does OER agree with RI Energy's characterization?

A: No. Based on SEA's analysis of RI Energy's interconnection queue data, which was

shared with RI Energy, OER believes that the data supports an allocation of 25 MW for Large Solar I. Although RI Energy communicated to SEA that it was possible that ASO#4 could conclude prior to the third open enrollment, SEA did not include such capacity in its analysis. Given this, it is possible that additional capacity could potentially bid into the 2026-2027 PY. SEA provided such clarification in its September 17 stakeholder presentation (see Schedule 6)

Q: Did RI Energy offer a proposed alternative or further comments following clarification?

A: No.

B. Recommended 2026-2027 Megawatt Allocation Plan

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

A: OER and the DG Board's proposed Megawatt Allocation Plan is shown in **SEA Table 3** below.

SEA Table 3 – DG Board Recommended Megawatt Allocation Plan (2026-2027 PY)

Renewable Energy Class	Eligible System Sizes	PUC Approved 2025-2026 PY MW Allocation Plan	Recommended 2026-2027 PY (MW_{DC})
Small Solar	<=25 kW_{DC}	9	3
Medium Solar	>25-250 kW_{DC}	7	9
Commercial Solar I	>250-500 kW_{DC}	9.5	8.5
Commercial Solar I (CRDG)	>250-500 kW_{DC}	0.5	0.5
Commercial Solar II	>500 kW-1 MW_{DC}	11.5	8
Commercial Solar II (CRDG)	>500 kW-1 MW_{DC}	1	1
Large Solar I	>1-<5 MW_{DC}	**20**	**25**
Large Solar I (CRDG)	>1-<5 MW_{DC}	5	5
Large Solar II	5 MW-<10 MW_{DC}	**30**	**20**
Large Solar III	10-<15 MW_{DC}	**15**	**15**
Large Solar IV	15-<39 MW_{DC}	0	0
Wind	≤ 5 MW_{AC}	3	3
Wind CRDG	≤ 5 MW_{AC}		
Anaerobic Digestion	≤ 5 MW_{AC}	1	1
Small Scale Hydropower	≤ 5 MW_{AC}		
Total		**112.50**	**94**

Q: With the plan shown in SEA Table 3 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. 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 for the 2026-2027 PY?

A: As shown in **SEA Table 2** 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 2026-2027 PY.

Q: Does this conclude your testimony?

A: Yes, it does.

DIRECT TESTIMONY OF JIM KENNERLY, SUSTAINABLE ENERGY ADVANTAGE, LLC

I. INTRODUCTION

Q: Mr. Kennerly, can you please state your name, employer, title, and role in the process?

A: My name is Jim Kennerly. I am a Director at SEA, and for the 2026-2027 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 clean energy and distributed energy resources?

A: I have fifteen years of experience at the intersection of energy policy, energy economics and markets for clean energy technologies. At SEA, I serve as a subject matter expert regarding distributed energy and battery energy storage markets, policies, regulation and program development.

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 U.S. Department of Energy's SunShot Initiative. Prior to that, I was a Regulatory and Policy Analyst at the North Carolina Sustainable Energy Association, and an Associate at ICF, working on its U.S. EPA ENERGY STAR Labeling and Residential team. 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.

Q: What topics or issues will your testimony pertain to?

A: My testimony will pertain to the cost-benefit analysis conducted on the 2026-2027 program plan in addition to the financing cost methodology adopted in ceiling price modeling.

II. FINANCING COST METHODOLOGY

A. Tax Equity Component of After-Tax Internal Rate of Return

Q: Why did SEA revisit its tax equity IRR assumption during the 2026-2027 PY program development process?

A: SEA revisited the tax equity after-tax equity IRR assumptions for two reasons. First, SEA's research indicated that FEOC requirements will result in a risk premium on tax equity after-tax equity IRR. Second, SEA conducted research on "baseline" (e.g., non-FEOC impacted) IRRs in response to the PUC's directive that any party seeking modifications to already-approved ceiling prices must provide evidence grounded in a comprehensive review of cost, performance, and financing inputs, and that current prices no longer yield a reasonable rate of return. To this end, SEA re-evaluated whether the tax equity return assumptions used in earlier drafts continued to reflect contemporary market conditions and investor expectations.

Q: How did SEA account for FEOC-related impacts on tax equity returns?

A: SEA included a FEOC-related risk premium of 25 basis points (bps) based on feedback from a major regional financier to account for increased compliance and legal risk via the purchase of FEOC compliance-specific insurance products beginning to emerge. Such insurance is expected to be required by said financiers to hedge against the risk a project is deemed fully ineligible for a credit due to FEOC noncompliance. The broader decline in national tax equity return requirements relative to SEA's prior assumptions more than offsets any FEOC-related premium. Consequently, the updated 9.00% tax equity IRR assumption remains appropriate and responsive to both FEOC-related considerations and the PUC's directive to ground financing assumptions in current market data.

Q: Did SEA account for updates to non-FEOC related tax equity IRR revisions?

A: Yes. SEA conducted a fresh review of available data on tax equity return requirements. This included evaluating nationally recognized benchmark sources to determine whether market-based return expectations had shifted since approval of the 2024–2026 ceiling prices. The goal was to ensure that, when viewed alongside other cost, performance, and financial assumptions, the tax equity IRR reflected current market reality rather than historical values.

Q: What information did SEA consider in reevaluating tax equity returns?

A: To comply with the PUC's directive to reevaluate all material financing inputs, SEA relied on the Norton Rose Fulbright 2025 Cost of Capital survey, a leading national benchmark for renewable energy financing conditions that has informed financing inputs adopted in prior PYs.[12] The survey is frequently used by investors, developers, and regulators to identify prevailing return requirements and capital market dynamics. SEA selected this source because it offers the most up-to-date, market-wide evidence on tax equity IRR expectations available to the industry.

Q; What did Norton Rose's survey indicate about contemporary tax equity IRR expectations?

A: The survey indicates that after-tax tax equity IRRs for "best," meaning lowest-risk and fully contracted, renewable energy projects currently fall within a 7.5%–8.5% range. This updated range is materially lower than the 9.75% tax equity IRR previously used in SEA's modeling.

Q: How did SEA incorporate this updated market information into its revised tax equity IRR assumption?

A: To align its financing assumptions with the updated evidence, in third draft pricing, SEA averaged the Norton Rose benchmark (8%) with its previous assumed IRR (9.75%, which included the FEOC risk premium), producing 8.875%, which SEA rounded to 9.00% given uncertainty regarding FEOC-related impacts on tax equity returns and potential investor return expectations specific to Rhode Island.

B. Interest Rates on Term Debt

Q: How did SEA update its interest-rate assumptions relative to the values used in the prior ceiling price analysis in Docket 23-44-REG?

A: SEA applied the same underlying methodology that was approved in Docket 23-44-REG, but updated the embedded market data to reflect current financial conditions. In the prior analysis, risk-free rates were based on market conditions as of 2023, combined with class-specific risk premiums to produce total interest rates for each technology class. In this filing, SEA refreshed the risk-free component using a weighted blend of October 2025 forward-looking Treasury-based expectations, while maintaining the same risk-premium structure adopted in Docket 23-44-REG.

[12] See Norton Rose Fulbright, Cost Of Capital: 2025 Outlook. Available at: https://www.projectfinance.law/publications/2025/january/cost-of-capital-2025-outlook/

This approach ensures direct comparability with the previously approved analysis while providing updated evidence, as requested by the PUC, on whether financing conditions have materially changed.

Q: What changes did SEA observe in underlying risk-free interest rates relative to those relied upon in Docket 23-44-REG?

A: SEA observed a modest increase in weighted-average risk-free rates relative to the risk-free values used in the 23-44-REG ceiling price analysis. The updated data show slightly higher Treasury-based expectations across the relevant debt tenors (10–15 years), reflecting the gradual upward drift in long-term interest-rate expectations since late 2023. Updating these values was necessary to assess whether current borrowing conditions differ materially from the conditions underlying the originally approved 2026 ceiling prices.

In addition, SEA observed that the "Market Consensus Forecast" previously utilized to forecast risk-free rates was largely flat over the long term (e.g., did not forecast significant decreases in rates through 2027), consistent with a scenario where the economy does not enter into a recession.[13] Given this, SEA considered revisions to its analysis to better capture the risk that the economy will enter into a recession.

Q: How did SEA revise the calculation of risk-free rates to account for a scenario where the economy slips into a recession?

A: First, SEA identified a risk-free rate forecast that is more consistent with a scenario in which the economy enters into a recession (provided by the Financial Forecast Center). Next, SEA reviewed several key macroeconomic indicators, including updated 10-year Treasury forward expectations, the ongoing yield-curve inversion, and the Federal Reserve's published probability of recession (just under 30%).[14] After review and opportunity for stakeholder comment, SEA adopted a blended average between the two risk-free rate forecasts based on the Federal Reserve's published probability of recession. The net impact of this revision was a reduction in the adopted interest rate inputs used in modeling, relative to a scenario where SEA simply adopted the "Market Consensus Forecast" used in prior PYs (see slide 27 of Schedule 6 for details).

Q: What updated total interest rates result from applying the revised risk-free rates and established risk premiums?

[13] Available at: https://econforecasting.com/forecast/t10y
[14] Available at: https://www.newyorkfed.org/medialibrary/media/research/capital_markets/prob_rec.pdf

A: SEA's final assumed interest rates are derived by applying updated risk-free rate forecasts to the technology-specific risk premiums used in the analysis conducted for the prices approved in Docket 23-44-REG. The resulting total interest rates incorporated into the updated 2026 modeling are:

- *Small Solar I/II:* 6.99%
- *Medium/Commercial Solar:* 7.11%
- *Large Solar:* 7.20%
- *Wind:* 7.45%

Q: Can you explain why these values differ by renewable energy class?

A: Yes. In short, the rates reflect different assumed loan terms, and the term premia associated with said loan terms. For example, while a Small Solar I/II project is assumed to receive a 10-year loan, a Large Solar or Wind project is assumed to receive a 15-year loan due to the longer tenor of their tariff compensation, and the "risk-free" rate for a 15-year loan term versus a 10-year loan term is higher due to financier perceptions of risk and uncertainty associated with longer tenors.

Q: If significant further changes in recession probabilities or interest rates overall occur between now and the start of the PY, has the DG Board provided OER (through SEA) with latitude to change the assumed interest rates for the 2026 PY?

A: Yes, and SEA will continue to carefully monitor conditions for interest rates relative to its modeled outlook.

C. Clean Energy Investment Credit (CEIC) Transferability

Q: How has SEA incorporated the availability of tax credit transferability inputs used in modeling?

A: Tax credit transferability is an element of the financing environment that informs the cost of capital reported to SEA through various sources. Given this, in assessing appropriate tax equity return assumptions, SEA implicitly considers tax credit transferability, and has since the original IRA transferability rules were finalized. In that time, tax equity transactions involving a transfer of tax liability have become commonplace and thus reflected in estimates of the cost of tax equity financing.

Q: In its comments during the program development process, what approach does RI Energy propose regarding the treatment of tax credit transferability?

A: In their third draft comments, RI Energy asserts that the availability of tax credit transferability under the Inflation Reduction Act (as revised by the OBBBA) should reduce financing costs, and suggests that SEA has not adequately reflected this effect (see Schedule 10).

Q: Does OER agree with RI Energy that SEA has not reflected these effects in its analysis?

A: No. Given that most tax equity transactions involve a transfer of tax liability rather than a traditional syndicated tax equity deal, SEA is confident the information received from Norton Rose Fulbright implicitly reflects this information. Furthermore, SEA's analysis indicated that its previous tax equity return assumptions were too high, and SEA revised them downward, which is consistent with the directional impact RI Energy claims transferability should have.

Q: Did RI Energy present any evidence that SEA's financing inputs were incorrect or propose alternative values?

A: No. RI Energy did not submit any evidence beyond these conclusory assertions that any of SEA's financing inputs were inaccurate, nor did RI Energy supply alternative recommended assumptions.

III. COST-EFFECTIVENESS OF 2025 PROGRAM YEAR MEGAWATT ALLOCATION PLAN

A. Detailed Cost-Effectiveness Methodology – 2026-2027 PY Small Solar Ceiling Prices and Megawatt Allocation Plan

Q: What methodology did SEA use to complete a BCA of the 2026-2027 PY MW Allocation Plan?

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[15] in completing this analysis, we believe that many well-vetted assumptions are included herein.

[15] 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.

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 and Docket 24-50-REG?

A: Yes.

Q: What tests did SEA utilize in its analysis?

A: SEA utilized three specific tests:

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[16]; and
3. A Rhode Island Ratepayer Test, which includes all monetizable benefits of the program's incentivized generation to ratepayers in Rhode Island.

Q: Relative to the BCA conducted in Docket No. 24-50-REG, how is SEA presenting BCA results for the aforementioned tests?

A: Consistent with SEA's approach in Docket 24-50-REG, SEA is presenting the results of

[16] In some of SEA's materials, this "Cost of Supply" test is also known as the New England Ratepayer test, since it incorporates ratepayer benefits experienced outside of Rhode Island.

its BCA in total dollar terms based on the proposed MW Allocation over a range of deployment scenarios. In Docket 24-50-REG, SEA 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. SEA 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.

However, based on recent enrollment trends, SEA's expectation is that deployment outcomes in the near-term are likely to be lower than the historical average of 51% deployment. Given this, SEA is presenting BCA results under a range of deployment scenarios, including full, 50%, 25% and 10% deployment to provide a more representative range of outcomes. Such scenarios were developed in consultation with RI Energy, and are consistent with the deployment scenarios presented by RI Energy in its presentation to the DG Board.

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 PY, that Medium and Commercial Solar I projects will reach commercial operation one year after selection, Commercial Solar II 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 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 2026-2027 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 4**.

SEA Table 4 - 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

B. Benefit-Cost Results: 2026-2027 PY Megawatt Allocation Plan

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

A: Our analysis found that under the Rhode Island Test, and regardless of whether economic development benefits are included, the benefits associated with the MW Allocation Plan (regardless of eventual subscription and commercial operation levels) exceed the tariff cost under the Rhode Island Test and thus provide a net benefit. Under both the Cost of Supply Test and the

Rhode Island Ratepayer Test, the benefits of the Megawatt Allocation Plan did not exceed the costs, regardless of how much allocation was deployed.

Q: What were the BCA results for the 2026-2027 PY Megawatt Allocation Plan using the Rhode Island Test?

A: As shown in **SEA Table 5**, in the absence of economic development benefits, our BCA found that the net benefits of the Megawatt Allocation Plan would be **$7.28 million** at 10% allocation deployment, **$18.21 million** at 25% allocation deployment, **$36.42 million** at 50% allocation deployment, and **$72.83 million** at full allocation deployment. When economic development benefits are included, the net benefits would be **$17.88 million** at 10% allocation deployment, **$44.71 million** at 25% allocation deployment, **$89.42 million** at 50% allocation deployment, and **$178.83 million** at full allocation deployment.

SEA Table 5 - Total MW & Benefits and Costs of 2026 PY Megawatt Allocation Plan (NPV ($), RI Test, With and Without Econ. Dev. Benefits)

BCA Type	***Full Allocation Deployed***	***50% Allocation Deployed***	***25% Allocation Deployed***	***10% Allocation Deployed***	***Full Allocation Deployed***	***50% Allocation Deployed***	***25% Allocation Deployed***	***10% Allocation Deployed***
Economic Development Benefits Applied?	No	No	No	No	Yes	Yes	Yes	Yes
Total MW Deployed	90.0	45.0	22.5	9.0	90.0	45.0	22.5	9.0
Total Benefits	$339,041,893	$169,520,947	$84,760,473	$33,904,189	$445,041,688	$222,520,844	$111,260,422	$44,504,169
Total Tariff Cost	$266,210,581	$133,105,291	$66,552,645	$26,621,058	$266,210,581	$133,105,291	$66,552,645	$26,621,058
Total Net Benefits (Solar Classes)	**$72,831,312**	**$36,415,656**	**$18,207,828**	**$7,283,131**	**$178,831,107**	**$89,415,553**	**$44,707,777**	**$17,883,111**
Benefit-Cost Ratio (BCR)	**1.27**				**1.67**			

Q: What were the BCA results for the 2026-2027 PY Megawatt Allocation Plan using the Cost of Supply Test?

A: As shown in **SEA Table 6**, our BCA found that the net benefits of the Megawatt Allocation Plan, would be **-$2.15** million at 10% allocation deployment, **-$5.37** million at 25% allocation deployment, -**$10.74** million at 50% allocation deployment, and **-$21.47** million at full allocation deployment.

SEA Table 6 - Total MW & Benefits/Costs of 2026-2027 PY Megawatt Allocation Plan A (NPV ($), Cost of Supply Test

BCA Type	***Cost of Supply Test – Full Allocation Deployed***	***Cost of Supply Test – 50% Allocation Deployed***	***Cost of Supply Test – 25% Allocation Deployed***	***Cost of Supply Test – 10% Allocation Deployed***
Total MW Deployed	90.0	45.0	22.5	9.0
Total Benefits	$244,737,925	$122,368,963	$61,184,481	$24,473,793
Total Tariff Cost	$266,210,581	$133,105,291	$66,552,645	$26,621,058
Total Net Benefits (Solar Classes)	**($21,472,656)**	**($10,736,328)**	**($5,368,164)**	**($2,147,266)**
BCR	**0.92**			

Q: What were the BCA results for the 2026-2027 PY Megawatt Allocation Plan using the Rhode Island Ratepayer Test?

A: As shown in **SEA Table 7**, our BCA found that the net benefits of the Megawatt Allocation Plan, would be **-$9.98** million at 10% allocation deployment, **-$24.94** million at 25% allocation deployment, -**$49.89** million at 50% allocation deployment, and **-$99.78** million at full allocation deployment.

SEA Table 7 - Total MW & Benefits/Costs of 2026-2027 PY Megawatt Allocation Plan (NPV ($), RI Ratepayer Test

BCA Type	***Rhode Island Ratepayer Test – Full Allocation Deployed***	***Rhode Island Ratepayer Test – 50% Allocation Deployed***	***Rhode Island Ratepayer Test – 25% Allocation Deployed***	***Rhode Island Ratepayer Test – 10% Allocation Deployed***
Total MW Deployed	90.0	45.0	22.5	9.0
Total Benefits	$166,435,555	$83,217,778	$41,608,889	$16,643,556
Total Tariff Cost	$266,210,581	$133,105,291	$66,552,645	$26,621,058
Total Net Benefits (Solar Classes)	**($99,775,026)**	**($49,887,513)**	**($24,943,756)**	**($9,977,503)**
BCR	**0.63**			

Q: Can SEA provide a detailed breakdown of the benefits and costs of the 2026-2027 PY Megawatt Allocation Plan by renewable energy class?

A: Yes, this information is contained in Schedule 12**.**

Q: Does this conclude your testimony?

A: Yes, it does.

Schedule 1 – Stakeholder Data Request and Survey

See file named 'Schedule 1 – Stakeholder Data Request and Survey.pdf'

Schedule 2 – Presentation for DG Board Meeting (July 28, 2025)

See file named 'Schedule 2 – Presentation for DG Board Meeting (July 28, 2025).pdf'

Schedule 3 - Presentation for Public Stakeholder Meeting No. 1 (July 30, 2025)

See file named 'Schedule 3 – Presentation for Public Stakeholder Meeting No. 1 (July 30, 2025).pdf'

Schedule 4 – First Draft Megawatt Allocation Plan (August 21, 2025)

See file named 'Schedule 4 – First Draft Megawatt Allocation Plan (August 21, 2025).pdf'

Schedule 5 - Presentation for DG Board Meeting (August 25, 2025)

See file named 'Schedule 5 – Presentation for DG Board Meeting (August 25, 2025).pdf'

Schedule 6 - Presentation for Public Stakeholder Meeting No. 2 (Sept. 17, 2025)

See file named 'Schedule 6 – Presentation for Public Stakeholder Meeting No. 2 (Sept. 17, 2025).pdf'

Schedule 7 - Presentation for DG Board Meeting (Sept. 29, 2025)

See file named 'Schedule 7 – Presentation for DG Board Meeting (Sept. 29, 2025).pdf'

Schedule 8 - Presentation on Third Draft of Ceiling Prices (Oct. 15, 2025)

See file named 'Schedule 8 – Presentation on Third Draft of Ceiling Prices (Oct. 15, 2025).pdf'

Schedule 9- Presentation for DG Board Meeting (Nov.17, 2025)

See file named 'Schedule 9 – Presentation for DG Board Meeting (Nov. 17, 2025).pdf'

Schedule 10 - Stakeholder Comments

See file named 'Schedule 10 – Stakeholder Comments.pdf'

Schedule 11 - REG 2026 BCA - Benefits Methodology

See file named 'Schedule 11 – REG 2026 BCA - Benefits Methodology.pdf'

Schedule 12 - REG 2026 BCA - Component Benefit Calculations

See file named 'Schedule 12 – REG 2026 BCA - Component Benefit Calculations.xlsx'