STATE OF RHODE ISLAND PUBLIC
UTILITIES COMMISSION

IN RE: THE RHODE ISLAND DISTRIBUTED	:	
GENERATION BOARD'S RECOMMENDATIONS	:	
FOR THE 2023 RENEWABLE ENERGY	:	DOCKET 22-39-REG
GROWTH PROGRAM YEAR	:	

Recommendations for the 2023 Renewable Energy Growth Program Year

DISTRIBUTED-GENERATION BOARD
& OFFICE OF ENERGY RESOURCES

NOVEMBER 16, 2022

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DISTRIBUTED GENERATION BOARD

2023 RENEWABLE ENERGY GROWTH PROGRAM 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 2023 Renewable Energy Growth Program Year ("RE Growth 2023 PY") to the Public Utilities Commission ("Commission" or "PUC"). The recommendations set forth herein, regarding classes, tariff term lengths, ceiling prices and megawatt allocation plan were approved by the DG Board and endorsed by the Office of Energy Resources ("OER"). In accordance with R.I. Gen. Laws § 39-26.6-4(b), OER, in consultation with the DG Board, engaged Sustainable Energy Advantage, LLC ("SEA") to develop recommended ceiling prices for review and approval by the DG Board and to provide other technical assistance regarding the Renewable Energy Growth ("REG") Program.

Goals and Objectives

The purposes of the REG Program are "to facilitate and promote installation of grid- connected generation of renewable energy; support and encourage development of distributed renewable energy generation systems; 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; diversify the energy generation sources within the load zone of the electric distribution company; stimulate economic development; improve distribution system resilience and reliability within the load zone of the electric distribution company; and reduce distribution system costs." See R.I. Gen. Laws § 39-26.6-1.

Consistent with such purposes, the anticipated outcomes for the RE Growth 2023 PY are the following:

1. A diversified renewable energy program with a portion of the megawatt ("MW") capacity allocated to support each sector.
2. When appropriate, continued decreases in ceiling prices in certain renewable energy classes.
3. Economic development with the state's renewable energy market.
4. Maintaining consistent and predictable REG Program and capacity targets from year-to-year for both residential and commercial customer-focused and stand- alone generation renewable energy companies, allowing such companies to operate, maintain staffs and develop complex projects that may have potential multi-year lead times before submitting a proposal to Rhode Island Energy.

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 Commissioner (ex officio, non-voting)
Vacant	Rhode Island Energy (ex officio, non-voting)[1]
Karen Stewart	Commerce Corporation (ex officio, non-voting)
John McCann	Energy and regulation law
Harry Oakley	Large commercial/industrial users
Samuel J. Bradner	Small commercial/industrial users
Mark Kravitz	Residential users
Jennifer Hawkins	Low-income users
Sheila Dormody	Environmental issues pertaining to energy
Laura C.H. Bartsch (Chair)	Construction of renewable generation

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

Renewable Energy Classes

Consistent with R.I. Gen. Laws § 39-26.6-3(15), § 39-26.6-4(a)(1), § 39-26.6-7(b), and § 39-26.6-7(c), please see **Table 2A** below which contains the DG Board's recommendations for renewable energy classes and eligible system sizes for the RE Growth 2023 PY. The recommended classes are no different from those approved by the PUC for the 2022 PY.

Table 2A - Recommended Renewable Energy Classes 2023 PY

Renewable Energy Class	Eligible System Sizes
Small Solar I	0-15 kW_{DC}
Small Solar II	>15-25 kW_{DC}
Medium Solar	>25-250 kW_{DC}
Commercial Solar I	>250-500 kW_{DC}
Commercial Solar II	>500- 1000 kW_{DC}
Large Solar	>1-5 MW_{DC}
Wind	≤ 5 MW_{AC}
Anaerobic Digestion	≤ 5 MW_{AC}
Small Scale Hydropower	≤ 5 MW_{AC}
Community Remote – Commercial Solar I	>250-500 kW_{DC}
Community Remote – Commercial Solar II	>500-1000 kW_{DC}
Community Remote – Large Solar	>1-5 MW_{DC}
Community Remote – Wind	≤ 5 MW_{AC}

Tariff Term Lengths

Consistent with R.I. Gen. Laws § 39-26.6-4(a)(1), please see **Table 3A** below, which contains the DG Board's recommendations for tariff lengths for the RE Growth 2023 PY.

Table 3A – Recommended Tariff Lengths 2023 PY	
Renewable Energy Class	**Tariff Length**
Small Solar I	15 Years
Small Solar II	20 Years
Medium Solar I	20 Years
Medium Solar II	20 Years
Commercial Solar I	20 Years
Commercial Solar II	20 Years
Large Solar	20 Years
Wind	20 Years
Anaerobic Digestion	20 Years
Small Scale Hydropower	20 Years
Community Remote – Commercial Solar	20 Years

Ceiling Prices

Consistent with R.I. Gen. Laws § 39-26.6-5(d) and § 39-26.2-5, please see **Table 4A** below, which contains the DG Board's recommendations for ceiling prices for the RE Growth 2023 PY. With this filing, OER and the DG Board respectfully request that the PUC select either the set of prices that assume post-tariff revenue at net metering credit rates, discounted for price and policy uncertainty (the "Including Post-Tariff Revenue" set) or the set that assumes that projects will operate until the end of their tariff term, at which point the project's owners would make a determination regarding whether to continue to operate (the "Excluding Post-Tariff Revenue" set).

OER and the DG Board make this respectful request in light of the ambiguity surrounding uncertainty with regard to the meaning of § 39-26.6-23(a), which states, in pertinent part:

> *(a) Net-metering credits for excess generation shall not be credited during the term of the tariff when the distributed-generation project is receiving performance-based incentive payments under*

the tariff. After the end of the term of the performance-based incentive tariff applicable to a distributed-generation project, net-metering credits for excess generation in any given month shall be credited to the net-metered account at the applicable rate allowed under the law.

Specifically, OER and the Board suggest that if the PUC believes that R.I.G.L. § 39-26.6-23(a) entitles REG projects to compensation for production at the applicable net metering rate without reconfiguration, it should select the "Including Post-Tariff Revenue" set of recommended prices, and if not, it should select the "Excluding Post-Tariff Revenue".

The differences between the approved ceiling prices for the 2022 PY and both potential sets of recommended ceiling prices for the 2023 PY are illustrated in **Table 4B** below. For additional information, please see the pre-filed testimony and schedules of Jim Kennerly and Tobin Armstrong, SEA, (Pages 21-24). Ceiling price trends from 2011-2022 are illustrated in **Table 4C and 4D** (Solar), **Table 4E and 4F** (Wind), **Table 4G and 4H** (Anaerobic Digestion) and **Table 4I and 4J** (Hydropower) below.

Table 4A - Recommended Ceiling Prices 2023 PY		
Renewable Energy Class	**Ceiling Price (¢/kWh)**	
	Including Post-Tariff Revenue	**Excluding Post-Tariff Revenue**
Small Solar I	27.75	31.25
Small Solar II	26.15	26.65
Medium Solar (>25-250 kW)	25.65	25.65
Commercial Solar I (>250-500 kW)	22.05	22.35
Commercial Solar II (>500-1000 kW)	19.05	19.55
Large Solar	14.35	15.45
Wind	19.15	19.95
Anaerobic Digestion	19.05	19.05
Small Scale Hydropower	31.95	32.45
Community Remote – Commercial Solar I (>250-500 kW)	25.15	25.15
Community Remote – Commercial Solar II (>500-1000 kW)	21.91	22.35
Community Remote – Large Solar	16.50	17.77
Community Remote – Wind	21.15	21.75

Table 4B – Ceiling Prices: Approved 2022 PY vs Recommended 2023 PY					
Renewable Energy Class	PUC Approved 2022 PY	DG Board Recommended 2023 PY		% Change between 2022 PY and 2023 PY	
	Including Post-Tariff Revenue	Including Post-Tariff Revenue	Excluding Post-Tariff Revenue	Including Post-Tariff Revenue	Excluding Post-Tariff Revenue
Small Solar I	31.05	27.75	31.25	-11%	1%
Small Solar II	27.55	26.15	26.65	-5%	-3%
Medium Solar (>25-250 kW)	24.45	25.65	25.65	5%	5%
Commercial Solar I (>250-500 kW)	19.25	22.05	22.35	15%	16%
Commercial Solar II (>500-1000 kW)	15.75	19.05	19.55	21%	24%
Large Solar	10.95	14.35	15.45	31%	41%
Wind	22.4	19.15	19.95	-15%	-11%
Anaerobic Digestion	25.55	19.05	19.05	-25%	-25%
Small Scale Hydropower	37.15	31.95	32.45	-14%	-13%
Community Remote – Commercial Solar I (>250-500 kW)	22.14	25.15	25.15	14%	14%
Community Remote – Commercial Solar II (>500-1000 kW)	18.11	21.91	22.35	21%	23%
Community Remote – Large Solar	12.59	16.50	17.77	31%	41%
Community Remote – Wind	24.6	21.15	21.75	-14%	-12%

Table 4C - Ceiling Price Trend for Solar

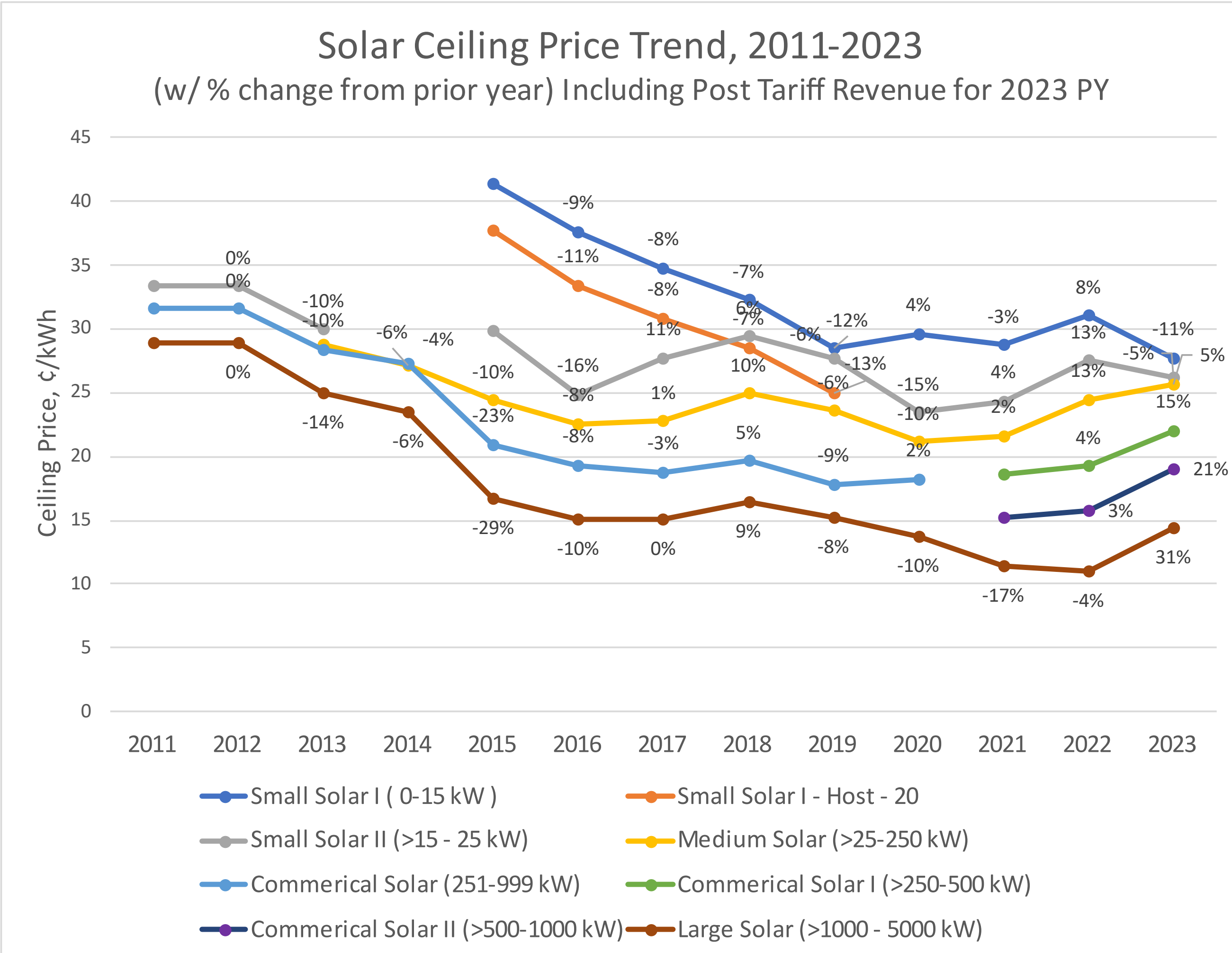


Table 4D - Ceiling Price Trend for Solar

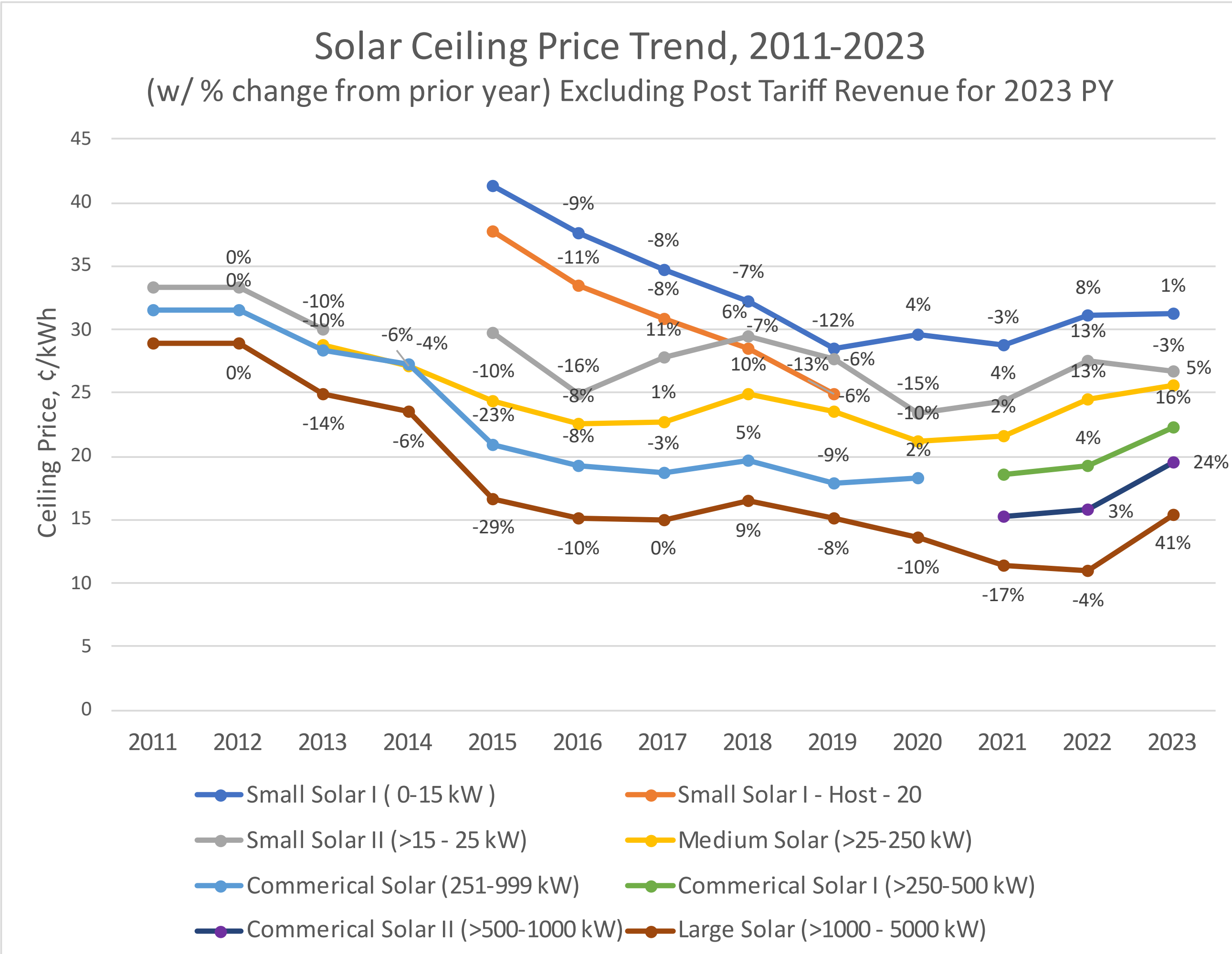


Table 4E - Ceiling Price Trend for Wind

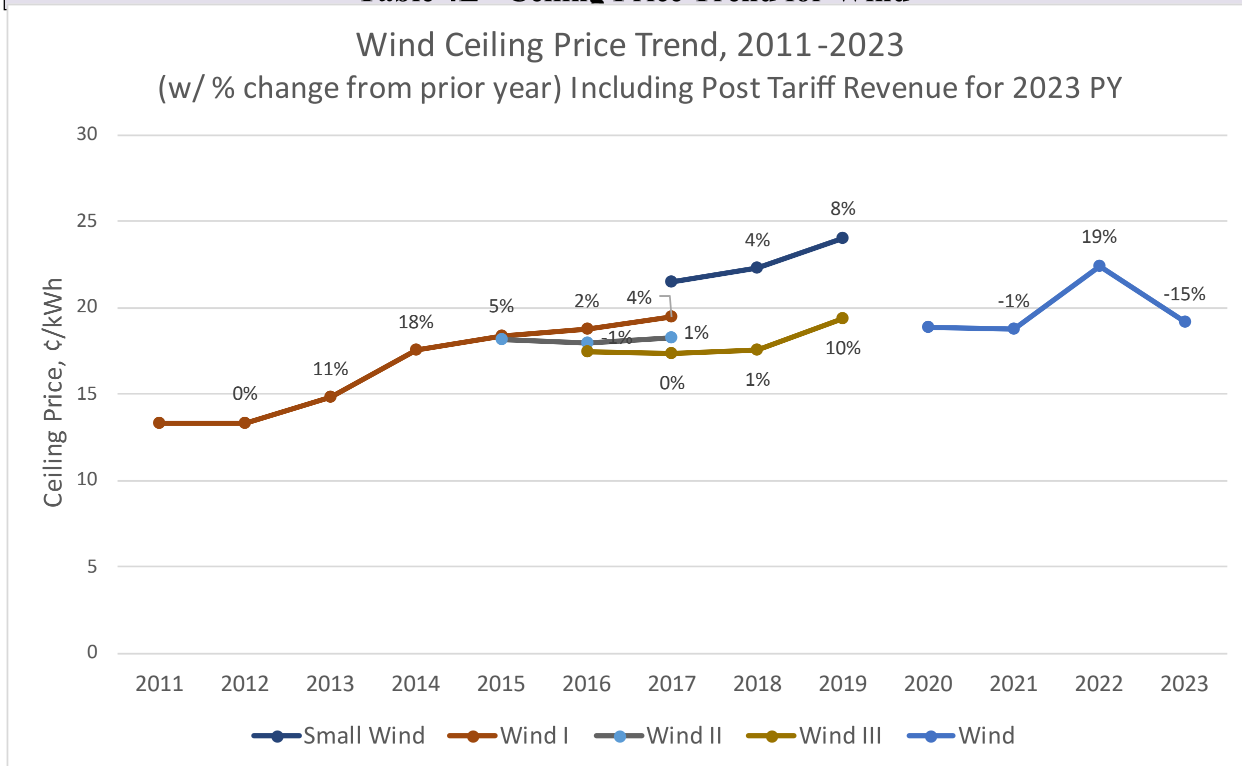


Table 4G - Ceiling Price Trend for Wind

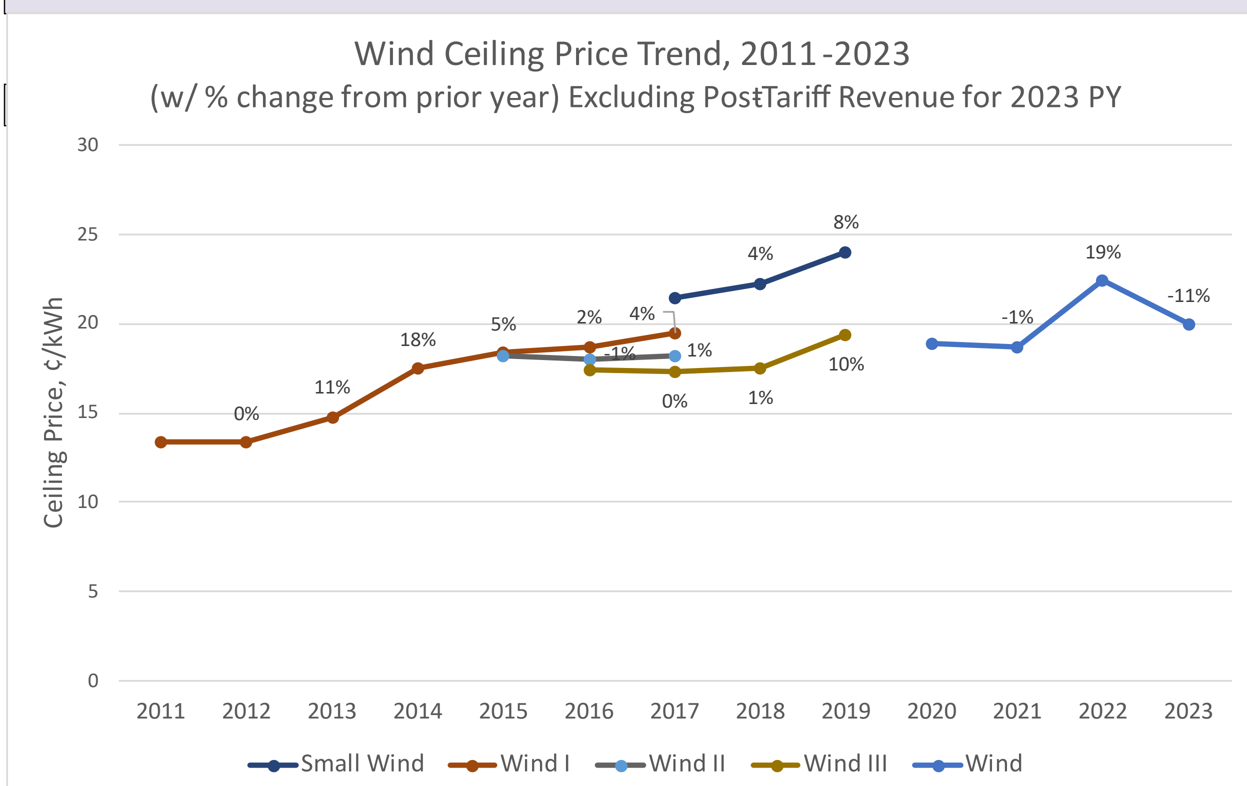


Table 4G - Ceiling Price Trend for Anaerobic Digestion

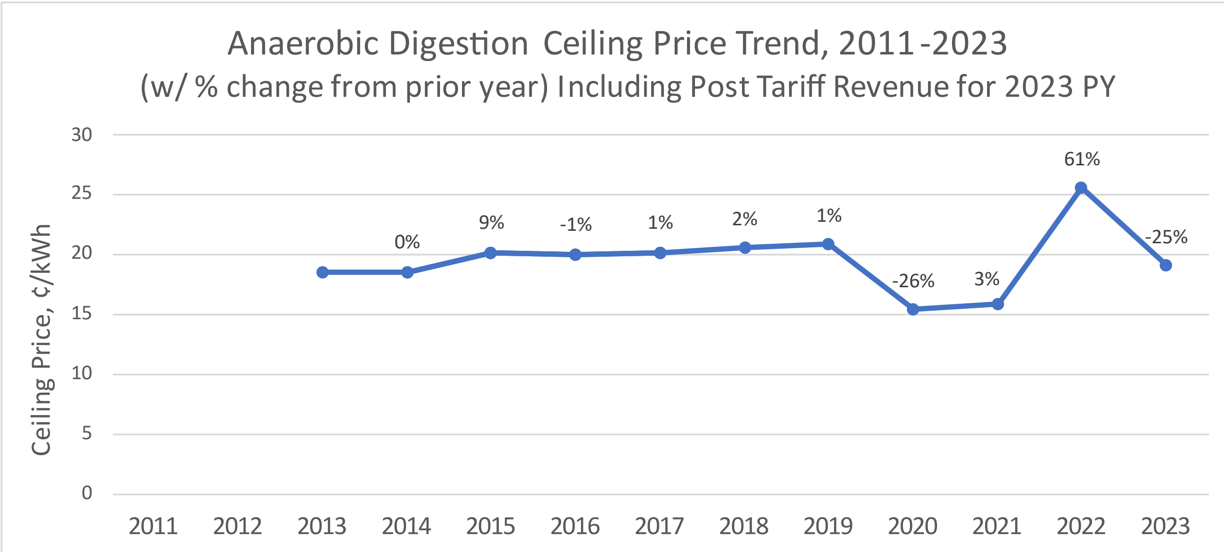


Table 4H - Ceiling Price Trend for Anaerobic Digestion

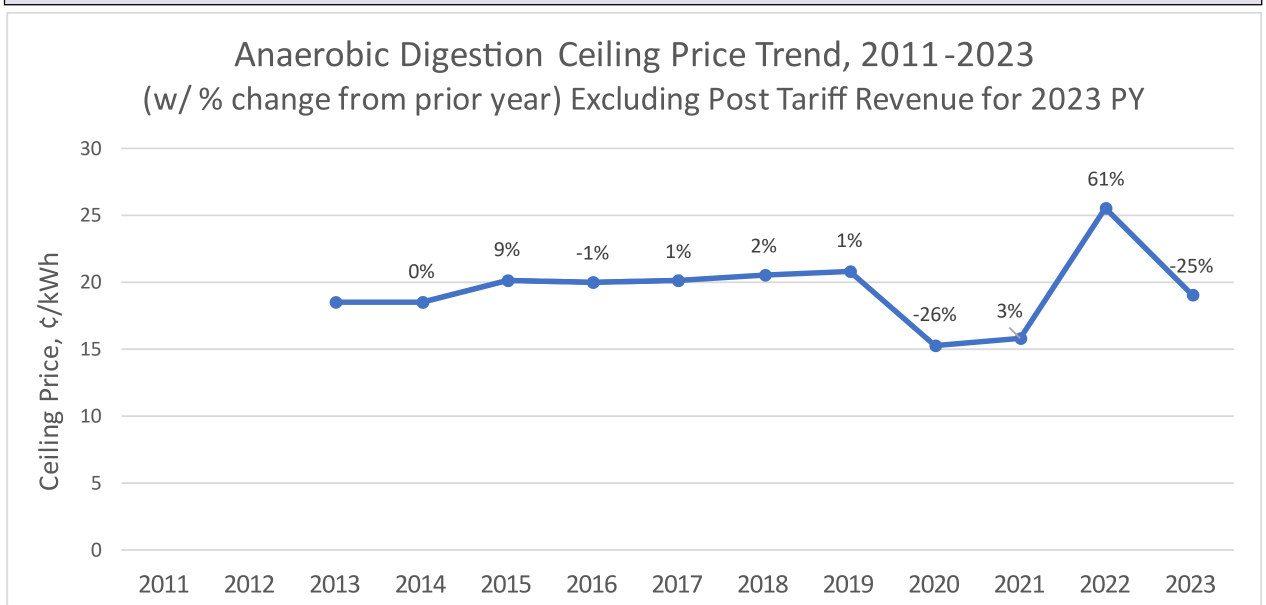


Table 4I - Ceiling Price Trend for Hydropower

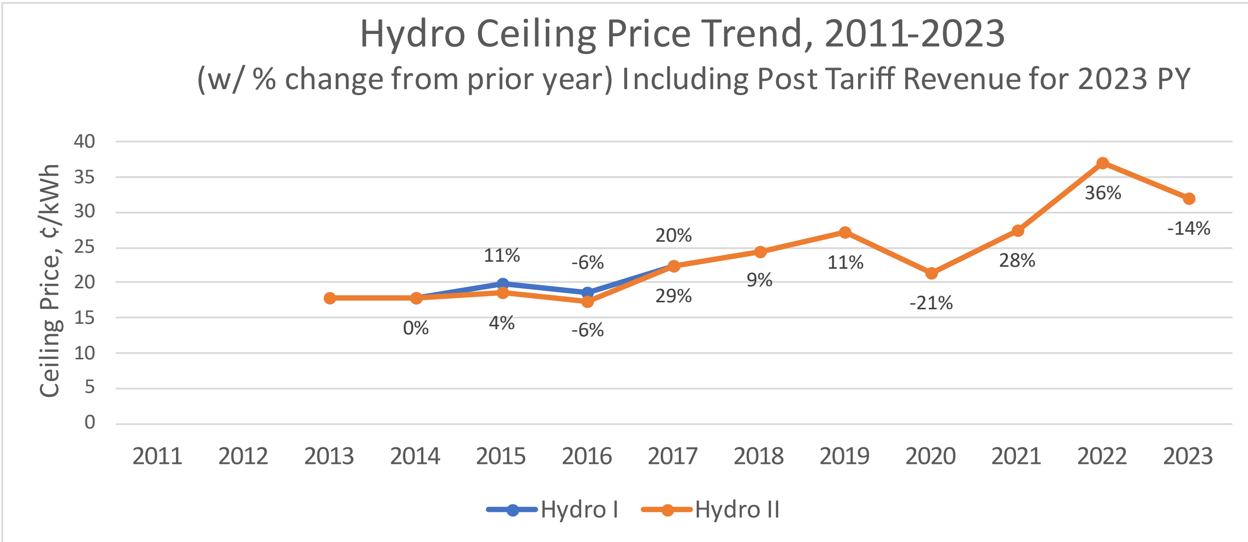
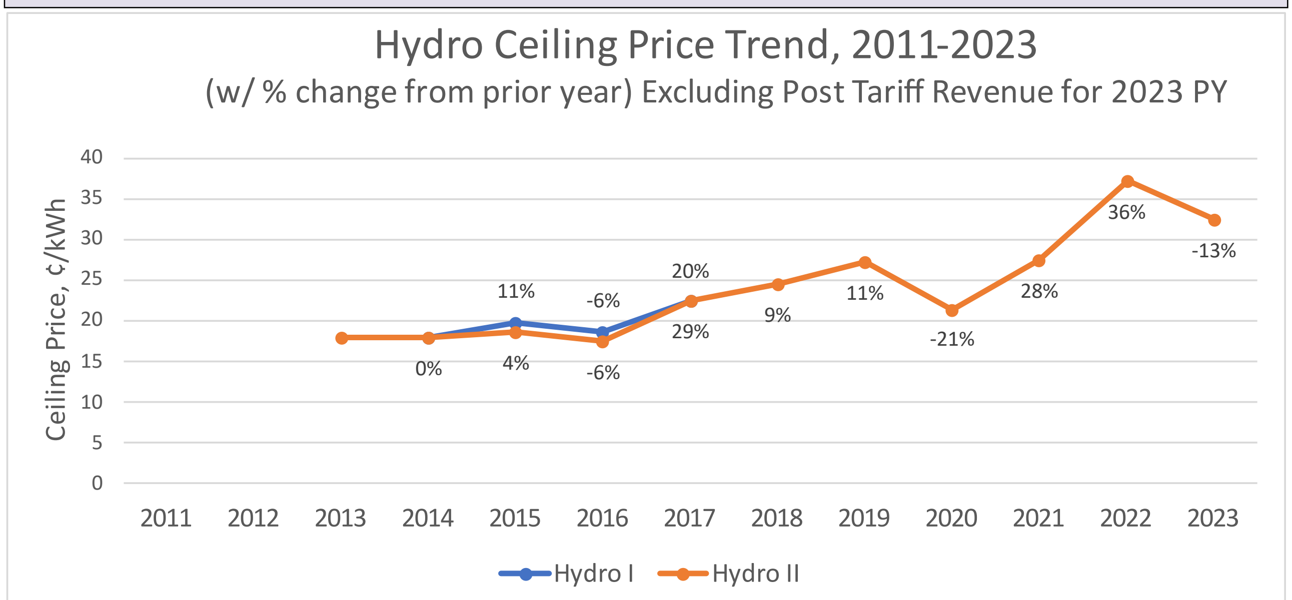


Table 4J - Ceiling Price Trend for Hydropower



Megawatt Allocation Plan

Consistent with R.I. Gen. Laws § 39-26.6-12(c)(5), please see **Table 5A** below which contains the DG Board's recommended allocation plan for the RE Growth 2023 PY. The changes between the approved megawatt allocation plan for the 2022 PY and the recommended allocation plan for the 2023 PY are illustrated in **Table 5B** below. The total megawatt number reflects the annual megawatt capacity (66.615 megawatts) for the RE Growth 2023 PY in addition to any unused or terminated megawatt capacity from the RE Growth 2017-2022 PYs. **Table 5C** below contains the recommended annual allocation plan for the RE Growth PY 2023.

Table 5A - Recommended Allocation Plan 2023 PY	
Renewable Energy Class	**Alloca**
Small Solar	9.0
Medium Solar	5.0
Commercial Solar I (>250-500 kW)	4.0
Commercial Solar II (>500-1000 kW)	8.0
Large Solar	27.615
Wind	3.0
Community Remote – Wind	
Anaerobic Digestion	1.0
Small Scale Hydropower	
Community Remote – Commercial I (>250-500 kW)	3.0
Community Remote – Commercial II (>500-1000 kW)	3.0
Community Remote – Large Solar	3.0
Total	**66.615**

Table 5B – Allocation Plan: Approved 2022 PY vs Recommended 2023 PY			
Renewable Energy Class	**DG Board Recommended and PUC Approved 2022 PY**	**DG Board Recommended 2023 PY**	**Change between 2022 PY and 2023 PY (%)**
Small Solar	6.950	9.0	29%
Medium Solar	5.0	5.0	0%
Commercial Solar I (>250-500 kW)	4.0	4.0	0%
Commercial Solar II (>500-1000 kW)	8.0	8.0	0%
Large Solar	24.25	27.615	14%
Wind	3.0	3.0	0%
Community Remote – Wind			
Anaerobic Digestion	1.0	1.0	0%
Small Scale Hydropower			
Community Remote – Commercial (>250-500 kW)	3.0	3.0	0%
Community Remote – Commercial (>500-1000 kW)	3.0	3.0	0%
Community Remote – Large Solar	3.0	3.0	0%
Total	**61.2**	**66.615**	

Table 5C - Recommended Allocation Plan for First Enrollment 2023 PY

Renewable Energy Class	Allocation in MW
Small Solar	9.0
Medium Solar	5.0
Commercial Solar I (>250-500 kW)	4.0
Commercial Solar II (>500-1000 kW)	8.0
Large Solar	27.615
Wind	3.0
Community Remote – Wind	
Anaerobic Digestion	1.0
Small Scale Hydropower	
Community Remote – Commercial (>250-500 kW)	3.0
Community Remote – Commercial (>500-1000 kW)	3.0
Community Remote – Large Solar	3.0
Total	**66.615**

* Any additional megawatt capacity that remains unused from the RE Growth 2022 PY Small Solar Class (closes on March 31, 2023) would be allocated to the 2023 RE Growth PY Small Solar Class.

The second (August) and third (October) enrollment quantities will be dependent on the results of the first enrollment.

Conclusion

After an extensive and transparent development process, the DG Board voted at its October 24, 2022, meeting to recommend the allocation plan, and further recommend that the PUC, based on what it believes to be consistent with R.I.G.L. § 39-26.6-23(a), select either the "Including Post-Tariff Revenue" or "Excluding Post-Tariff Revenue" sets of recommended ceiling prices.

The DG Board and OER respectfully request the PUC consideration for approval of the recommendations for the RE Growth 2023 PY.

Pre-Filed Direct Testimony of Jim Kennerly and Tobin Armstrong
Sustainable Energy Advantage, LLC

Jim Kennerly and Tobin Armstrong testify under oath as follows:

Mr. Kennerly, please state your name, employer, and title.

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

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

I have over twelve years of experience with climate and energy policy and its impact on markets for clean energy technologies, and ten years of professional experience directly related to renewable energy market and policy development. At SEA, I lead the company's Policy Analytics practice and serve as a subject matter expert regarding distributed energy resource markets and policies. In addition to serving the Rhode Island Office of Energy Resources ("OER") and Distributed Generation Board ("DG Board"), our distributed energy team has undertaken custom consulting work for the Massachusetts Department of Energy Resources ("MA DOER"), the Maine Governor's Energy Office, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities, the Massachusetts Clean Energy Center, the New York State Energy Research and Development Authority, the Connecticut Public Utility Regulatory Authority, the New Hampshire Office of Consumer Advocate, the Massachusetts Attorney General's Office, the Connecticut Green Bank, the Clean Energy States Alliance, Vote Solar, the Natural Resources Council of Maine ("NRCM"), and other public sector and not-for-profit entities, as well as a wide variety of buy-side and sell-side solar and distributed energy market participants.

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

I have a Master of Public Affairs degree from the Lyndon B. Johnson School of Public Affairs at the University of Texas at Austin and a Bachelor of Arts in Politics from Oberlin College.

Have you previously appeared before this Commission to provide testimony?

Yes. Each year since 2018, I have sponsored the direct (and as needed, rebuttal) testimony filed by the Office of Energy Resources (OER) and Distributed Generation Board (DG Board) regarding recommended Renewable Energy Growth (REG) program ceiling prices. I have also sponsored testimony in support of changes to the design of the program as requested, from time to time, by OER and the DG Board.

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

I am sponsoring the portions regarding the ceiling price development process, the impacts of the

Inflation Reduction Act of 2022 on the recommended prices, the main drivers of upward and downward pressure on the recommended prices, the changes to our installed capital cost methodology, and the changes to our debt financing assumptions.

Mr. Armstrong, please state your name, employer, and title.

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

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

I have eight years of experience related to renewable energy policy, and four years of professional experience with modeling solar energy production and incentives requirements. At SEA, I lead the company's distributed generation market molding, am the lead modeler for our Massachusetts Solar Market Study (MA-SMS), and have played a leading role in multiple engagements that utilize SEA's CREST model.

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

Have you previously appeared before this Commission to provide testimony?

Yes. 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.

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

I am sponsoring the portions regarding the changes to the Small Scale Hydroelectric Investment Tax Credit assumptions, the changes to the Small Solar I taxation assumptions, and the changes to the post-tariff revenue assumptions.

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

Please describe SEA's background related to renewable energy technologies.

SEA is a consulting advisory firm that has been a national leader on 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.

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

Since 2011, SEA has served as a technical consultant to OER and, beginning in 2014, to the DG Board in their implementation of the Distributed-Generation Standard Contracts Program ("DG Program"), R.I. Gen. Laws § 39-26.2-1 et seq., and the Renewable Energy Growth Program ("REG Program"), R.I. Gen. Laws § 39-26.6-1 et seq. SEA's role is to advise OER and the DG Board to make informed recommendations with respect to technology- and size-specific ceiling prices based on detailed research and analysis.

What was SEA's role in the development of the 2023 REG program?

SEA was hired by OER and the DG Board to conduct detailed research and analysis of regional distributed renewable energy markets, collect additional insight through public meetings, written comments, and interviews, and then to recommend ceiling prices for each technology-, ownership- and size-specific class established by OER and the DG Board.

<u>**Overview of Ceiling Price Development Process**</u>

Please describe the process that SEA utilizes to develop recommended ceiling prices.

Each year, SEA acts as a joint facilitator of a lengthy process to request, gather and analyze cost and performance data from current and prospective market participants and other interested parties. Throughout the process, SEA solicits empirical evidence from stakeholders regarding market trends and practices and offers multiple opportunities for interested parties to participate in public meetings and submit written comments, which are encouraged to address both general market observations and to respond directly to specific data requests and draft proposed ceiling price recommendations. SEA also conducts interviews with active market participants each year. SEA incorporates all the intelligence gained from this market research into its modeling of Ceiling Prices, utilizing the National Renewable Energy Laboratory ("NREL") Cost of Renewable Energy Spreadsheet Tool ("CREST") model to generate recommended ceiling prices through multiple rounds of analysis. The process included three presentations to the DG Board and stakeholders. At the final presentation, the DG Board discussed and approved the recommendations proposed by SEA which are reflected in the Report and Recommendations.

When were the presentations made to the DG Board and stakeholders?
SEA first presented a summary of the Inflation Reduction Act, and its implications for REG-eligible projects, to stakeholders held by webinar on August 23, 2022. Next, SEA shared its first draft of the recommended ceiling prices at a public meeting held by webinar on August 30, 2022, during which it presented the first draft of proposed ceiling price inputs and results for all technology categories. SEA presented the second draft of proposed inputs and results at a stakeholder meeting held by webinar on September 22, 2022. The final ceiling price recommendations for all technology categories were presented at a DG Board public meeting held by webinar on October 24, 2022, where the prices were approved. SEA then identified a technical correction which revised certain ceiling prices. The revised ceiling prices, which are reflected in this testimony, were approved by the DG Board on November 14. SEA's four presentations are provided as **SEA Schedule 1, SEA Schedule 2, SEA Schedule 3**, and **SEA Schedule 4** (containing both the prices approved at the October 24 meeting and the technical corrections approved at the November 14 meeting)**,** respectively.

Are those presentations attached to the Report and Recommendations?

Yes.

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

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

Yes. The CREST model is a discounted cash flow analysis tool published by the National Renewable Energy Laboratory (NREL). SEA was the primary architect of the CREST model, which was developed under contract to NREL. The CREST model is available to the public without charge, and is fully transparent (that is, all formulas are visible to, and traceable by, all users). CREST was created to help policymakers develop cost-based renewable energy incentives and has been peer reviewed by both public and private sector market participants. The model is designed to calculate the cost of energy, or minimum revenue per unit of production, necessary for the modeled project to cover its expenses, service its debt obligations (if any), and meet its equity investors' assumed minimum required after-tax rate of return.[2] 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.

Were the CREST models made available to stakeholders?

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.

<u>**Ceiling Price Development – Stakeholder Engagement Process**</u>

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

The number of responses to both the data request and survey, including those obtained via interviews and follow-ups, are summarized in **SEA Schedule 5** below. SEA successfully followed up with stakeholders with targeted outreach requesting research calls relating to specific inputs and to better understand the atypically low program participation in 2022 (with emphasis on the lack of Large Solar bids received in the first and second Open Enrollment). However, SEA made clear that stakeholders were free to offer formal and informal comments throughout the process.

Copies of all the survey instruments can be found in **SEA Schedule 6**.

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

SEA received comments regarding three of the four eligible technologies (solar, wind, hydroelectric) from a combination of project developers, financiers, and the DPUC. As during the 2022 program year stakeholder process, SEA received no feedback from Anaerobic Digestion stakeholders. Throughout the process, SEA vetted all the stakeholder feedback and made more than a dozen adjustments to inputs or calculation methodologies as a direct result of stakeholder feedback.

[2] 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.

For summaries of comments provided by stakeholders and how SEA responded to them, please see **SEA Schedules 2-4**, SEA's stakeholder presentations delivered as part of the ceiling price development process. The DPUC's comments on the first and second draft of the ceiling prices are provided as **SEA Schedule 7** and **SEA Schedule 8**, respectively.

Are ceiling price recommendations based exclusively on stakeholder input?

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 be difficult to justify, and would risk over-compensating project owners at the expense of ratepayers. Thus, the 2023 recommended ceiling prices take other recent data sources (which are described and linked in **SEA Schedules 2-4**) 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.

Did the DG Board 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?

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

Did SEA, on behalf of the DG Board, consider all the stakeholder feedback given in the development of recommended 2023 ceiling prices?

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

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

Yes. The consulting team collaborated extensively with consultants to the DPUC and directly incorporated a number of their suggested changes to the ceiling price inputs.

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

Yes.

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

No.

<u>Ceiling Price Development – Proposed Ceiling Prices, Renewable Energy Classes, and Eligible System Sizes</u>

Can you verify the renewable energy classes included in the Report and Recommendations, and provide a comparison of the renewable energy classes and corresponding eligible system sizes approved by the PUC for the 2022 program year with those proposed by OER and the DG Board for the 2023 program year?

OER and the DG Board's proposed renewable energy classes and corresponding eligible system sizes can be found in **SEA Schedule 9**. The 2022 approved classes and eligible size ranges are identical to the classes and eligible size ranges proposed for the 2023 program year.

Can you verify the 2023 program year ceiling prices included in the Report and Recommendations?

Yes. The recommended ceiling prices, tariff terms and eligible system sizes for each renewable energy class for the 2022 REG program year are summarized in **SEA Schedule 10**.

Are these the same ceiling prices that were developed through the CREST modeling in conjunction with stakeholders and OER, and recommended to the DG Board?

Yes.

Do the proposed 2023 ceiling prices differ from the 2022 ceiling prices? If yes, please quantify the percentage change for each category.

Yes. The percentage change between the proposed 2023 ceiling prices and the final 2022 ceiling prices can be seen in **SEA Schedule 11** below.

<u>Ceiling Price Development – Accounting for Enactment of the Inflation Reduction Act of 2022</u>

Since the Commission's approval of the 2022 program year ceiling prices in late March 2022, have there been any significant changes in federal law that affect the REG program, and related ceiling prices?

Yes. <u>Public Law (P.L.) No. 117-169 - Inflation Reduction Act of 2022</u> (hereafter the IRA, or the Act) makes substantial changes to federal tax incentives for renewable energy projects.

Please list and describe the changes the Act makes to federal law that may ultimately become relevant for REG-eligible projects.

The Act makes the following changes relevant to the proposed set of projects eligible for the 2023 program year:

- Sets the full Investment Tax Credit (ITC, and ITC in Lieu of Production Tax Credit (PTC)) value of 30% for 2023 (relative to a prior law value of 22%);
- Establishes prevailing wage and apprenticeship requirements for projects greater than or equal to 1 MW_{AC} (rather than 3 MW, the baseline requirement associated with <u>An Act</u>

Relating To Public Utilities And Carriers - Labor Standards In Renewable Energy Projects (Chapter 381));

- Allows projects less than or equal to 5 MW_{AC} to include interconnection costs (including for equipment not owned by the taxpayer) in the Investment Tax Credit cost basis;
- Establishes a successor Clean Energy Investment Credit for projects starting construction after Jan 1, 2025; and
- Establishes various bonus tax credits for projects meeting certain domestic content requirements, located in energy communities or sited on brownfields, or serving low income offtakers.

A summary of the Act provided by SEA to stakeholders is provided in **SEA Schedule 1.** Modeling implications relevant to the 2023 REG program year are provided starting on slide 47.

Please also list the changes the Act makes to federal law that are directly accounted for in the 2023 recommended prices.

The 2023 recommended prices directly account for the:

- Restoration of the full ITC and ITC in Lieu of PTC (ILoPTC) value of 30% for 2023;
- The above-described prevailing wage requirements;
- Inclusion of interconnection costs in the Investment Tax Credit cost basis; and
- (For Small Scale Hydroelectric class projects only) Establishment of a successor Clean Energy Investment Credit for projects placed in service after Jan 1, 2025.

Can SEA trace the levelized cost impact on the proposed 2023 program year prices to the changes in federal law brought by the Inflation Reduction Act of 2022?

Yes. The IRA resulted in a reduction in the ceiling prices for all resource classes. For Solar classes, the IRA reduced ceiling prices by approximately 10% on average, relative to a scenario in which it did not become law. For non-solar classes, the IRA reduced ceiling prices by approximately 20% on average relative to a scenario in which it did not become law. A comparison of the recommended 2023 ceiling prices with and without the IRA-induced changes is provided in **SEA Schedule 12**.

Are there provisions of the Inflation Reduction Act for which implementation uncertainty remains?

Yes. As with the rest of the Internal Revenue Code, the U.S. Department of the Treasury (Treasury) and the Internal Revenue Service (IRS) develop regulations to implement each relevant provision of the Act. Furthermore, various other provisions directly relevant to the ceiling prices (bonus Investment Tax Credit (ITC) values for projects benefiting low-income and/or disadvantaged communities and prevailing wage/apprenticeship requirements) are subject to rulemaking by the U.S. Environmental Protection Agency and the U.S. Department of Labor, respectively. It is our understanding that all of the initial regulations related to the law are likely to be completed no later than Spring 2023.

In developing inputs for the recommended 2023 PY ceiling prices, did SEA make any specific assumptions regarding the (still forthcoming) implementing regulations associated with any of the provisions of the IRA incorporated into the ceiling prices?

No, we did not. We hewed as closely as possible to the text of the statute and is unaware of any assumptions it has made that run contrary to the statute. Though we allow that it is possible that some of the implementing regulations could be implemented in certain ways that impact clean energy markets in the Northeast, we anticipate being able to track and adopt these changes in future year ceiling prices, as needed.

Did SEA assume all projects with a nameplate capacity of greater than 1 MW are capable of complying with the IRA's prevailing wage requirements necessary for claiming a full value tax credit for projects 1 MW and greater? Why or why not?

Yes, we did, for two reasons. First, as discussed in the stakeholder process, recently-enacted state law requires all projects greater than 3 MW to pay prevailing wages. According to stakeholder estimates, the cost of complying with Rhode Island's new prevailing wage requirements was $57.50/kW$_{DC}$ for eligible Solar renewable energy class projects, and $130/kW$_{DC}$ for eligible Wind renewable energy class projects. Second, even if the new state law had not passed – and in light of SEA's upfront capital expenditure assumptions for Large Solar, Large Solar CRDG, Wind and Wind CRDG, the benefits of receiving the full ITC value of 30% (rather than 6% for not complying) significantly outweigh the added cost premium associated with prevailing wage compliance.

Why are Small Scale Hydroelectric or Anaerobic Digestion renewable energy class projects not assumed to include an incremental cost estimate associated with paying prevailing wage?

Overall, neither Chapter 381 (referenced above) nor the relevant IRA provisions appear to apply to these projects, since the proxy project is smaller than 1 MW.

Why does SEA not directly incorporate the various bonus credits for domestic content, "energy communities", or projects benefiting low income and/or disadvantaged communities into the ceiling prices?

We continue to believe that setting ceiling prices that have a strong chance of attracting a sufficient number of bids from market participants is necessary for the success of any ceiling price-based procurement design. Simply put, if state law and policy aim to have bidders make the effort to bid, the prices must be attractive enough for them to do so. SEA further believes that a necessary element in ensuring such prices are attractive enough to receive bids is to utilize cost, performance and financing assumptions that are:

1. As reflective of typical projects in Northeast distributed energy markets as possible;
2. Likely to provide more benefits than costs to both project owners and ratepayers (such as assuming that the benefits of a 30% vs. 6% ITC value outweigh the compliance cost); and
3. Not subject to significant uncertainty (such as unfinished implementation rules and regulations in which the agency has significant discretion, or hard limits on participation in such an incentive).

We apply this three-part test to the each of the potentially viable bonus credits for ITC-eligible projects below:

- **10 Percentage Point Domestic Content Bonus:** While other provisions of the IRA allow for incentives to upstream domestic manufacturers, distributed energy projects in the Northeast will continue, in the near term, to rely heavily upon significant project components (or shares of components) manufactured overseas and imported into the United States. In addition, at present, the specific rules for such domestic content – which could be made more or less stringent than the text of the law might imply – have not yet been finalized by Treasury and the IRS. Without more information, SEA is unable to develop a clear enough estimate of the incremental cost of receiving the 10% bonus credit, and thus the net value of assuming the inclusion of the bonus value itself.
- **10 Percentage Point "Energy Communities" Bonus:** Recently, SEA has developed estimates of the levelized cost of Large Solar-scale projects sited on brownfields (which are eligible for the "energy communities" credit) in Maine in a separate client engagement that suggest that the benefits of the 10 percentage point bonus credit could, in some cases, outweigh the incremental capital and operating costs associated with siting projects on brownfields. Furthermore, an analysis undertaken in 2021 by Synapse Energy Economics[3] suggests that there is sufficient technical potential to allow such projects to participate (and potentially underbid a ceiling price based on a 30% ITC value). However, we note that it is unclear based on the Synapse analysis that sufficient brownfield technical potential exists (or that said technical potential could economically interconnect with Rhode Island Energy's distribution system) to constitute a large enough share of Large Solar capacity to make brownfield siting a default assumption. Moreover, Treasury and the IRS have also not completed their rulemaking surrounding brownfield eligibility within the suite of "energy communities" eligible projects, thus subjecting brownfield viability to further uncertainty.
- **10 Percentage Point Credit for Siting in "Low Income" Community or Disadvantaged Community":** Similar to Large Solar-scale projects sited on brownfields, we have also developed estimates for projects sited in a low-income community, for which it appears that there are no specific incremental capital or operating costs to participate. However, the program (under which a bonus 10 percentage point value is available) has a maximum nationwide annual limit of 1,800 MW per year. Furthermore, the IRA provides no specific guidance regarding the allocation approach for eligible capacity for this benefit. Finally, the rules related to the program (which must be developed by Treasury and the U.S. Environmental Protection Agency (EPA) will likely not be completed until at least February 2023 (as explicitly required in the legislation). Therefore, it is impossible to be certain at this time whether there is sufficient eligible capacity in Rhode Island (or technical potential, given that the Treasury/EPA rulemaking is not yet complete) to assume that all projects in any given renewable energy class can qualify for this bonus value.
- **20 Percentage Point Credit for "Low Income Benefit" Projects:** Similar to the 10 percentage point bonus credit for projects sited in a low income community, projects eligible for a 20 percentage point bonus credit for projects directly serving low income participants with 50% of the project's output could potentially cost less to develop than a project with a 30% credit, depending on the project's cost of customer acquisition and management, However, such projects also must adhere to the same combined 1,800 MW nationwide limit as the 10 percentage point bonus credit simply for siting in a low income community, and are also subject to the same further Treasury/IRS and EPA rulemakings, which creates uncertainty that cannot be overcome for their adoption into the base ceiling price calculations.

[3] Synapse Energy Economics, Inc. *Solar Siting Opportunities for Rhode Island*. March 2021. Available at: https://www.synapse-energy.com/solar-siting-opportunities-rhode-island-0

Does the lack of inclusion of ITC bonus credit assumptions in the recommended 2023 ceiling prices mean that ratepayers cannot benefit from these tax provisions?

No, not at all. In fact, at least some of the projects that would have revenue requirement reductions relative to the incremental costs (if any) of claiming the bonus credits will be more successful in under-bidding a ceiling price based on a 30% credit value. Thus, their selections in Open Enrollments would be likely to reduce ceiling prices in future program years, and would be unlikely to crowd out projects that are not able to take advantage of these credits.

Is it possible that, in the absence of added steps to ensure data fidelity and integrity, the above-described bonus credits could complicate the calculation of future REG ceiling prices?

Yes. During this year (and in past years) our team has received installed cost information from Rhode Island Energy that is self-reported by the bidder and does not indicate which tax credit type (or bonus credit) the project has elected to claim. Without this information, our analysis of accepted bids for the calculation of proxy project upfront capital costs could skew higher than the as-bid values suggest.

Does SEA have a plan to track the usage of various bonus credits in REG Open Enrollment bids in 2023 (and potentially thereafter)?

Yes. We have requested (and Rhode Island Energy has agreed) to require future program applicants to specify which tax credit bonuses, if any, they plan to qualify for so that SEA can better understand and categorize the resulting bid prices and installed cost data associated with such projects.

<u>**Ceiling Price Development – Changes from 2022 Approved Solar Prices Unrelated to Inflation Reduction Act of 2022**</u>

Please describe the most impactful drivers of changes in the proposed 2023 Program Year ceiling prices for the Solar categories relative to those approved for the 2022 Program Year.

Similar to the approved 2022 ceiling prices, the recommended 2023 ceiling prices reflect a mix of changes that place upward and downward pressure on costs and prices. I describe this mix of drivers of upward and downward pressure on the proposed ceiling prices below.

<u>Drivers of Upward Pressure on Recommended 2023 Solar Ceiling Prices</u>

- *Increases in Installed Capital Costs for All Solar Projects:* SEA has made upward revisions to the assumptions for installed capital costs. These changes are the result of project costs for REG-eligible Solar projects (particularly those for Solar >25 kW) rising more significantly than our team originally anticipated when recommending the 2022 prices. These increases can be more clearly observed in the significant under-subscription of the 1st and 2nd Open Enrollments of the 2022 program year. Furthermore, supplemental SEA analysis suggests that the prices of a number of categories of Solar >25 kW projects have, in recent years, provided bidders with less pricing flexibility to offer bids below the ceiling prices than in prior years. In an environment in which project costs are increasing faster than anticipated, SEA believes these changes are necessary to ensure that the amount of capacity procured during the 2023 program year does not fall short of simply procuring even the annual targets for the Solar >25 kW renewable energy classes, let alone ensuring that the target capacity in those classes will reach commercial operation. **We discuss these issues in greater detail on pages 30-33, which relate to changes to installed cost assumptions.**

- *Increases in Interest Rates on Term Debt for Solar >25 kW:* As a result of the Federal Reserve's efforts to slow the rate of inflation in the broader economy (including the inflation observed in costs for REG-eligible renewable energy projects, as discussed above), interest rates on term debt for all Solar >25 kW projects have risen. However, this increase was tempered by a change in SEA's approach to calculating interest rates on term debt, which was enabled via receipt of a term sheet from a debt financier for REG-eligible projects in Rhode Island that relied on a simplified formulation for the debt. **We discuss these issues in greater detail on pages 33-36, which relate to debt assumptions.**
- *Shortening of Debt Term for Medium and Commercial Solar Projects:* Based on the same above-mentioned term sheet, SEA shortened the assumed debt term for Medium, Commercial I and Commercial II projects to 13 years from 15 years. The 13-year value is based on an average of the previous 15-year value with the 10-year value shown in the term sheet. **We discuss these issues in greater detail on pages 33-36, which relate to debt assumptions.**
- *Reduction in Debt Share (and Increases in Equity Share) in Capital Stack for All Projects:* As a result of the increase in interest rates on term debt, and the shortening of the debt term for Medium Solar projects – changes that increase annual debt service costs– SEA has reduced the assumed share of debt in the capital stack for proxy projects to restore required debt service coverage ratios. **We discuss this issue in greater detail on pages 33-36, which relate to debt assumptions.**
- *Increased Land/Site Lease Costs for Solar >25 kW:* The proposed prices also include increases in assumed land/site lease costs for all Solar >25 kW projects. The final input values represent averages of the previous input and documented lease agreements newly shared with our team.
- *Increase in Fixed Operations and Maintenance (O&M) Costs for Large Solar Projects:* Based on a database of information received from a market participant, SEA restored its pre-2022 program year assumptions for Fixed O&M costs for Large Solar (and thus, indirectly, Large Solar CRDG projects) to \$11/kW-yr (from \$8/kW-yr).

<u>Drivers of Downward Pressure on Recommended 2023 Solar Ceiling Prices</u>

- *Small Solar I Taxation Assumption Changes:* In response to feedback from the DPUC and PUC, and information received from Rhode Island Energy, SEA reduced the amount of project compensation assumed to be taxable, as well as the assumed effective tax rate for residential host project owners. **We discuss this issue in greater detail on page 41, which relates to the changes to Small Solar I tax assumptions.**
- *Accounting for Year-on-Year Cost Pressures Expected to Affect Solar Projects in 2022 Open Enrollments:* While SEA is proposing ceiling prices that reflect a significant increase in current-year installed capital cost assumptions, SEA is reverting to incorporating a downward-trending year-on-year change term to account for changes between 2022 and 2023 (given that 2023 bids will likely be based on prices for procured components at that time), rather than one that reflects an upward term as for the 2022 approved prices. However, the recommended prices assume a very conservative level of year-on-year cost reduction for eligible projects based on the most conservative National Renewable Energy Laboratory 2022 Annual Technology Baseline (ATB), which was benchmarked against analysis from industry consultants Wood Mackenzie. **We discuss these issues in greater detail on pages 30-33 of our testimony, which relate to changes to installed cost assumptions.**

- *Increases in Post-Tariff Compensation Values (For Prices in Which Post-Tariff Revenue is Assumed):* As a result of changes in natural gas and power market fundamentals, SEA also now assumes higher wholesale energy prices as a component of net metering rates. **We discuss these issues in greater detail on pages 38-41 of our testimony, which relate to changes to post-tariff revenue assumptions and their applicability.**
- *Reduced Sponsor Equity IRR Values for Medium Solar Projects:* To align the sponsor equity IRR assumptions for Medium Solar and Small Solar II projects (all of which have similar host customer owners), SEA reduced the assumed return assumptions for Medium Solar projects to the values assumed for Small Solar II.

For a full list of changes considered and undertaken for the proposed 2023 prices, please see **SEA Schedules 2-4**.

<u>Ceiling Price Development – Changes from 2022 Approved Wind, Hydro and Anaerobic Digestion Prices Unrelated to Inflation Reduction Act of 2022</u>

Please describe the most impactful drivers of changes in the proposed ceiling prices for the Wind classes.

- *Increases in Assumed Interest Rates on Term Debt:* As noted above regarding the Solar ceiling prices, the increases in 10- and 20-year Treasury yields have driven up the cost of debt financing for Non-Solar renewable energy projects as well. Furthermore, our revised analysis assumes an additional 25 basis point increase for Wind projects, to account for greater resource-related production uncertainty (e.g., the more unpredictable nature of wind than the sun). **We discuss these issues in greater detail on pages 33-36 of our testimony, which relate to debt assumptions.**
- *Reduction in Debt Share (and Increase in Equity Share) in Capital Stack for Wind Projects:* Also similar to the Solar renewable energy classes, and to meet minimum debt service coverage requirements, SEA increased the amount of required equity (and reduced the share of debt commensurately) for Wind projects.

For a full list of changes for these resources, considered and undertaken for the recommended 2023 prices, please see **SEA Schedules 2-4**.

Please describe the most impactful driver of changes in the proposed Ceiling Prices for the Anaerobic Digestion ("AD") and/or Small-Scale Hydropower ("Hydro") categories.

Similar to our assumptions for Wind projects, we assume an increase in interest rates on term debt for AD and Hydro projects (including an added risk term to account for Hydro resource variability), as well as increases in equity shares (at the expense of project debt). The values for Small Scale Hydroelectric were left unchanged since the change in interest rates on term debt did not affect modeled minimum coverage requirements. We also increased the tax equity returns for AD projects to ensure these values were in line with broader tax equity market assumptions. However, we increased several operating cost inputs for Hydro projects, following consultations with Hydro market participants.

For a full list of changes for these resources, considered and undertaken for the proposed 2022 prices, please see **SEA Schedules 2-4**.

<u>Installed Cost Assumptions for Solar Renewable Energy Classes for Projects >25 kW</u>

In general, what is the purpose of a ceiling price in a procurement-based distributed generation program structure like the one utilized for projects greater than 25 kW?

In a competitive procurement-based distributed generation program (like the REG program) a ceiling price is intended to provide a reasonable upper bound on the performance-based incentives allowable under such a program to provide ratepayers with protection against anti-competitive practices and to ensure that program participants do not receive returns significantly in excess of than those necessary to incent development.

In other words, given healthy competition, the ceiling price is not intended to represent the ultimate performance-based incentive intended for participating projects, but rather reflects a starting point under which competitive dynamics can identify the most cost-optimized projects and deliver the greatest benefits to ratepayers at the least cost.

In the context of the REG program, how would you define healthy and unhealthy competition?

We define healthy competition as a state in which a wide array of market participants are induced to bid via sufficiently attractive ceiling prices, and where bidders are provided with sufficient pricing flexibility to allow for competitive dynamics to reveal the fair market price for different types of development. In a state of healthy program competition, bid offerings should reflect informed pricing for well-developed projects that have a high probability of reaching commercial operation.

Conversely, unhealthy competition can be characterized by a limited number of program participants choosing to bid (or not bid) under maximum bid prices that may not allow for bidders to submit bids that reflect the costs they are experiencing in the market. Under such a scenario, projects may bid into the program at the ceiling price and with little margin for error in their project economics, producing functionally speculative bids with a higher chance of attrition. Other projects that are unable to visualize a path forward under the ceiling price may forego program participation, leading to a lack of competition and revealed pricing.

Please describe the Solar renewable energy class results in the First and Second Open Enrollments of the 2022 program year.

The First and Second Open Enrollment of the 2022 program year yielded atypically low participation, especially from the Large Solar resource class which did not receive any eligible bids for either Open Enrollment. For comparison, the first Open Enrollment of the 2021 program year yielded 30.9 MW of selected capacity, whereas the first Open Enrollment of the 2022 program year yielded only 4 MW of selected capacity.

Since the start of the Renewable Energy Growth program in 2015, how have accepted bid prices for Solar projects compared to the applicable ceiling prices for the annual Open Enrollments?

In general, the bid prices received under each program year's open enrollments have trended towards the ceiling price since 2015. Projects selected during the 2018 program year realized the highest reductions in bid prices as compared to the ceiling price, with bids for Large Solar averaging 22% lower than the ceiling price. During the 2021 program year, on the other hand, bids for Large Solar averaged 1% below the ceiling price. An analysis of bid prices in relation to ceiling prices, by program year, is provided in **SEA Schedule 13**.

Do you believe that these results, coupled with the results of the 2022 1st and 2nd Open Enrollments, suggest the presence of a state of healthy competition for Solar renewable energy class projects greater than 25 kW?

No, we do not. The 2022 program year Open Enrollments, in which participation was well below long-term averages for the 1st and 2nd Open Enrollments (particularly for larger projects) suggests an absence of healthy competition.

Does SEA believe it is necessary to make changes to its approach to restore healthy competitive dynamics?

Yes, we do.

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

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

How did SEA alter its approach to calculating installed cost for projects greater than or equal to 25 kW (i.e., those subject to competitive procurement) during the 2023 ceiling price development process?

Given the 2022 program year's atypically low participation thus far, we adjusted the cost quartiles for selected projects in the state databases used to derive assumed installed cost to enable the receipt of competitive, market-based bids representing projects likely to reach commercial operation. Specifically, we derived our installed cost inputs for medium and commercial projects based on an average of the median and 25th percentile costs from state databases and REG bid values, as opposed to just 25th percentile costs. For large solar, we utilized an average of the average and median costs from state databases and REG bid values, as opposed to just 25th percentile costs. For all non-Small Solar classes, we also limited its inclusion of REG bid data to the current program year (rather than the current and prior program year) to ensure that outdated cost data did not bias the assumptions used for the 2023 ceiling price development process. Given the robust 2022 Program Year participation in the Small Solar classes, we did not adjust our approach to calculating Small Solar installed cost.

In addition, we revised the year-on-year cost adjustments used to transform the 2022 installed cost figures derived via the methods discussed above into forecasted 2023 installed cost figures. During the 2022 ceiling price development process, we computed year-on-year cost decline assumptions as the balance of the Energy Information Administration (EIA's) Short Term Energy Outlook (STEO) on the producer price index (PPI) for all commodities (as a proxy for inflationary pressure experienced by firms) and the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB), to capture fundamental cost declines for solar. However, EIA's STEO now forecasts declining producer costs in 2023 relative to 2022. As such, it no longer makes sense to incorporate the STEO-based values into the calculation of year-on-year cost declines, as doing so would double count cost declines with ATB. Given this, and the 2022 program year's performance as discussed above, for the proposed 2023 ceiling prices, SEA utilized the 2022 NREL ATB's conservative case values (provided in **SEA Schedule 14**). The installed cost inputs, by resource class, resulting from these methods, as compared to the installed cost inputs adopted during the 2022 program year ceiling price development process, are provided in **SEA Schedule 15.**

Is SEA concerned that its change in approach could result in excessive costs for ratepayers?

No, we are not. As noted previously, the purpose of the ceiling prices is to attract bids that are both competitive and sufficient to ensure the project can reach commercial operation with compensation at its as-bid value. Furthermore, we account for these as-bid values by averaging the installed costs from these projects into the calculation for ceiling prices one year in the future. As such (with all factors held equal, and under the unchanged aspects of our approach) the more that market participants choose to participate, the more likely that the bids received in the 2023 Open Enrollments will reduce the 2024 recommended ceiling prices. Finally, removing bids from 2 years prior is also likely to reduce future year ceiling prices. This is because under normal conditions, these installed cost values are likely to be higher than current (or expected future) values.

<u>Financing Assumptions</u>

Please describe how SEA changed its approach to calculating interest rates on term debt and (in the case of Medium and Commercial projects) the assumed project debt term, and why.

For first draft of the 2023 PY prices, we utilized the same approach as it used for the 2022 prices, which was to estimate the change in interest rates based on changes in the yield on 10- and 20-year US Treasuries and overnight financing rates. In response to SEA's first draft prices, the DPUC suggested that the resulting interest rates produced by this method may be inappropriately high given its understanding of market conditions (see **SEA Schedule 7**). Following receipt of this feedback, we then sought input from market participants, and were supplied with a term sheet specific to a commercial REG facility that revealed financiers were building debt based on treasury yields plus a risk premium for a ten-year term. We adopted this approach in our modeling and revised the assumed debt term for the Medium and Commercial Solar renewable energy classes to 13 years to reflect an average of our previous assumed term (15 years) and the term provided in the term sheet (10 years). The components of SEA's revised interest rates can be found in **SEA Schedule 16**.

Did the DPUC comment on the revised approach in later comments to your team?

Yes. In their comments on the second draft prices (see **SEA Schedule 8)**, the DPUC stated that it supported the changes and did not recommend any further adjustments.

Would it be reasonable to assume that if the Federal Reserve's Federal Open Markets Committee (FOMC) were to reduce the federal funds rate in the future, that it would likely result in lower 10- and 20-year treasury yields, and thus lower assumed interest rates on term debt?

Yes, it would. In our experience, rates for 10- and 20-year Treasury yields tend to rise and fall with changes in the federal funds rate. However, the Federal Reserve is still likely to *raise* the federal funds rate at least once more (and potentially twice more) during late 2022 and early 2023, which we currently anticipate will cause rates to peak near to the beginning of the year. Overall, we are confident our assumed debt terms will track closely with the expected behavior of 10- and 20-year

Treasury bonds (plus a fixed risk premium) over the whole of 2023.

Why are interest rates on term debt for projects with shorter repayment terms lower, and higher for those with longer terms?

All factors equal, a shorter-term loan poses less risk over time to a debt provider than a longer-term loan for the same amount of capital, given that a longer term has higher repayment risk. Similar to commercial banks or other debt providers, these differences also drive the difference in pricing for Treasury yields purchased in the open market.

Does a higher interest rate on term debt for larger projects with longer debt terms correspond to a higher cost to ratepayers?

No, it does not. Despite the fact that the interest rate is somewhat higher for these projects, the difference between the two rates is small enough that the longer-term results in lower debt payments closer to Year 1 of project operation. This reduces the net present value (NPV) of the costs of the projects in question, and thus lowers the project's revenue requirement (and thus, ceiling price) for projects with longer-term debt offers.

Are the interest rates on term debt assumed for the 2023 recommended prices based on an offer of debt financing provided to a portfolio of projects, rather than simply to a single project?

Yes, it is. As described above, the term sheet for the offer of debt as the 10-year Treasury yield plus 325 basis points over 10 years that we modeled our debt assumptions around was for debt financing for a portfolio of projects to be built in Rhode Island. As such, we believe that these values represent a reasonable cost to ratepayers, given that the financing offer spreads the risk across a larger portfolio of assets, rather than a single asset.

Why did SEA change the assumed debt/equity ratios for both Solar and Non-Solar renewable energy classes?

When a debt provider considers the amount it is willing to lend to a project or project portfolio, it requires that a project's EBITDA[4] meet a minimum level of debt service coverage. For Solar renewable energy class projects, we assume this cash flow must be a minimum annual average of 1.25 times the project's debt service payments. For non-solar projects we assume a ratio of 1.35 times.

When interest rates increase (holding cash flow available for debt service constant), the size of the project (or portfolio) loan is reduced because there is less cash flow available to pay down principal. When this occurs, equity investment must make up the difference.

If actual or expected interest rates were to fall in 2024 and thereafter, would it be reasonable to expect that the share of project debt could rise to a higher level, and thus reduce the cost of financing the project, all other factors equal?

Yes, it would, because in that instance, the relationship of the magnitude of debt service to the project's cash flow would likely drop (all other factors held equal), and the project would be able to accept more debt financing, since debt has a lower cost of financing than equity.

[4] Earnings Before Interest, Taxes, Depreciation and Amortization

Can you explain why, when the new ITC value for all Solar renewable energy class eligible projects is now 30%, is the share of tax equity of total equity in the capital stack less than the share it was when the applicable ITC value was 26%?

Yes. In response to stakeholder comments and evidence regarding the amount of ITC value that is realized in the capital stack, we adjusted the tax equity investor contribution to 35% of total capital for Solar renewable energy class projects greater than 25 kW. This represents a slight reduction to the proportion of tax equity to total equity, thereby slightly increasing the amount of assumed sponsor equity in the capital stack.

Is SEA willing shift the cap on total tax equity upward if it were demonstrated that most deals are securing levels of tax equity greater than 35%?

Yes. If tax equity investors increase the total amount of capital they are willing to put into projects receiving the 30% credit value, we will propose ceiling prices that assume an increase in the use of tax equity.

Did SEA change its approach to assuming the use of accelerated depreciation in setting ceiling prices for the Solar and Non-Solar renewable energy classes as a result of the IRA's enactment?

Yes. With the IRA's passage, wind projects now have access to the ITC in lieu of the Production Tax Credit (ILoPTC) once again, following a lapse in that access after the end of calendar year 2021. As a result, tax equity investors are likely to once again be unwilling during 2023 (as they have been when they have access to federal renewable energy tax credits) to simultaneously accept bonus depreciation (rather than 5- or 7-year Modified Accelerated Cost Recovery System (MACRS) depreciation. Given this ongoing preference on the part of tax equity investors, our team decided to eliminate consideration of bonus depreciation for any project, since the IRA now provides full ITC and ILoPTC access for Solar and Non-Solar projects alike.

In addition, as part of assuming that Small Scale Hydroelectric projects would now be eligible for a 30% credit under the terms of the successor Clean Energy Investment Credit, our team also changed the assumed depreciation approach for that resource from 7-year MACRS to 5-year MACRS.

Did SEA receive feedback from the DPUC regarding its assumptions related to accelerated depreciation?

Yes, we did.

Please summarize this feedback.

In their comments (see **SEA Schedule 7 and SEA Schedule 8)**, the DPUC accurately noted that as a result of the passage of the IRA, renewable energy project owners can now benefit from the ability to transfer tax credits to taxpayers better positioned to use them. As a result, the DPUC reasoned, the ceiling prices must assume that eligible projects can claim the bonus depreciation rate for projects placed in service in 2024.

Did SEA adopt this proposed change? Why or why not?

After careful consideration of the DPUC's suggested approach, our team chose not to adopt it. We did this for three main reasons:

- Although we acknowledge the DPUC's point that the new transferability could notionally allow some investors to use bonus depreciation when they could not before, we believe it is too early to assume this across the board, and whether it is possible to do it is very specific to the investor in question.
- Finally, even if it were available and an approach that investors wanted to start using, bonus depreciation is a placed-in-service regime (rather than based on the year in which the project started construction). This means that projects relying on bonus depreciation will have to take the bonus value in place at the time of commercial operation. Since many larger projects of all types have longer interconnection delays (often now approaching 2-3 years, or longer, from project qualification) than smaller projects of all types, it is unclear that bonus depreciation, if not extended beyond the end of 2026, would be something that would be possible for either tax or sponsor equity partners to claim. As such, even if we did adopt the DPUC's approach, we do not believe it would be prudent to assume 2024 bonus depreciation values across the board.
- As discussed earlier in this testimony, the IRS is still considering its approach to regulations to implement the tax credit transferability provisions. In the absence of final regulations from the IRS, or greater market participant experience with the issue, we are uncertain what the precise terms of such a credit transfer might be for each type of eligible REG project type.

Would SEA be open to adopting the changes sought by the DPUC if changes or clarifications in federal law or regulations justify the change?

Yes, we certainly would. Given that it is always our goal to appropriately balance the costs of the program to ratepayers with providing a sufficient market signal for development, our team plans to continue to monitor the market in order to:

- Determine if transferability becomes a common practice, the terms on which such transfers are made, and what impact it should have on the financing assumptions associated with the ceiling prices; and
- Whether the enhanced transferability provisions encourage financiers to start utilizing bonus depreciation to the benefit of REG-eligible projects (and thus, indirectly, to ratepayers).

<u>**Small Scale Hydroelectric Class Investment Credit Eligibility**</u>

Did SEA receive feedback from the DPUC regarding the tax treatment of Small Scale Hydroelectric projects, in light of the passage of the Inflation Reduction Act of 2022? If so, please summarize this feedback.

Yes, we did. The DPUC argued that the Hydro class ceiling price should be established assuming qualification for a 30% Investment Tax Credit rate given the extension of tax credits and the new Clean Energy Investment Tax Credits for projects starting construction after Jan 1, 2025 established by the Inflation Reduction Act. The DPUC's comments can be found in **SEA Schedule 7 and SEA Schedule 8.**

Did SEA adopt the changes sought by the DPUC? Why or why not?

Yes. After consulting with Small Scale Hydroelectric market participants, we determined that, given the new IRA provisions, assuming that Small Scale Hydroelectric projects can qualify for the successor Clean Energy Investment Credit (CEIC) is appropriate.

Please describe SEA's methodology for adjusting the Small Scale Hydroelectric financing assumptions to accommodate a 30% investment credit.

We now calculates the Hydro ceiling price assuming qualification for the 30% CEIC. As a result, we increased the assumed tax equity share relative to sponsor equity, allowed the project to qualify for 5-year MACRS treatment (rather than 7-year, in the absence of the CEIC), and included interconnection costs in the basis for calculating the value of the CEIC.

__Interconnection Costs__

How do the recommended 2023 ceiling prices account for the cost of distribution system interconnection?

Each year, we request Rhode Island Energy's (previously National Grid's) database of Rhode Island interconnection costs on a project-by-project basis. In prior program years, the interconnection cost values were not specifically added to the build costs we collected in other Northeastern states (since interconnection costs are presumed, based on experience, to be included), but were instead used to remove interconnection costs from the basis for the ITC, and from utilizing 5-year MACRS depreciation, a form of accelerated depreciation. However, given the enactment of the IRA, which allows for inclusion of interconnection costs in the ITC basis, we did not need to treat interconnection costs separately from other installed costs in its modeling for the 2023 ceiling price development process.

Please describe how SEA calculated the upfront capital costs associated with interconnection.

As in previous years, we calculated the average cost of interconnection across Rhode Island in the dataset provided by Rhode Island Energy, which included data through the middle of 2022. However, given the slowdown in interconnection and progress to commercial operation caused by the pandemic, we widened the scope of analysis to include the full year 2021, as well as the available 2022 data. **SEA Schedule 17** below shows these interconnection costs for the Solar and Wind classes.

Does the interconnection approach differ for the Hydro and AD classes?

Given the relative scarcity of Hydro and AD projects, the value of the interconnection cost assumption has not changed from prior stakeholder guidance. Given the enactment of the IRA, interconnection costs are not treated separately from other installed costs, consistent with the solar classes.

Did SEA consider the potential costs of transmission interconnection when developing the ceiling prices?

Yes. As the Commission is aware, Rhode Island Energy's affiliate New England Power (NEP), the Affected System Operator (ASO) for Rhode Island, has been required by ISO-NE rules to conduct an increasing number of transmission interconnection studies for projects greater than 1 MW_{AC}, including for projects not directly connected to the transmission system, since late 2019/early 2020.

These studies are now, in essence, required for nearly all projects greater than or equal to 1 MW_{AC}, given that most substations in Rhode Island now or will soon require transmission-level study for projects of that size.

During the past three ceiling price development process, stakeholders have raised a number of issues regarding the costs and delays associated with both transmission and distribution level impact studies (as well as distribution interconnection individual and group studies), including (but not limited to):

- Increased overall distribution and/or transmission study timelines and costs (including, increasingly, multi-year interconnection-specific delays);
- The increasing likelihood that any projects ≥1 MW will be included in transmission-level ASO studies (and the risks associated with such potential delays and costs);
- The increasing risk that projects (as in Massachusetts) run the risk of being assessed system modification costs that cannot be absorbed by project owners as a result of either ASO or distribution-level studies;
- The increasing frequency of assessment of Direct Assignment Facilities (DAF) charges by New England Power and/or Narragansett Electric; and

Nevertheless, our team has concluded, as we did with regard to the 2022 approved prices, that we are not well-positioned to propose solutions for projects in extended transmission and/or distribution studies that would impact the 2023 program year. Furthermore, we continue to cite the series of fundamental, institutional, and practical challenges that inhibit OER, the DG Board, and our team from proposing credible and statutorily permissible solutions, as well as the unfinished nature of the PUC's efforts in Dockets 5205 and 5206.

In short, while the Renewable Energy Growth Act requires the ceiling prices to reflect typical project costs in Rhode Island and the Northeast region, it is unclear if our team has either the necessary information (given the unfinished state of many transmission and/or distribution impact studies, as well as the strict confidence that the details of those studies are held in) to accurately estimate what the quantifiable costs and risks are. We are also not confident that we have the ability to recommend to this Commission, through the recommended ceiling prices, how developers should be compensated for them.

<u>Post-Tariff Revenue Assumptions</u>

Prior to the 2022 ceiling price development process, how did SEA account for post-tariff revenue?

Prior to the 2022 ceiling price development process, we accounted for post-tariff revenue in its CREST modeling by incorporating forecasted wholesale energy and REC revenue into the modeled project's revenue stream following the conclusion of the tariff period and continuing through the end of the project's useful life. However, in cases in which such post-tariff revenue was unable to cover the project's operating expenses, we would limit the term of the analysis to the tariff period to prevent such post-tariff operating losses from increasing the calculated ceiling prices.

During the 2022 ceiling price development process, what prompted SEA to make changes to its approach?

During the 2022 ceiling price development process, it was brought to SEA's attention that R.I. Gen. Laws (R.I.G.L.) § 39-26.6-23(a) states, in pertinent part:

After the end of the term of the performance-based incentive tariff applicable to a distributed-

generation project, net-metering credits for excess generation in any given month shall be credited to the net-metered account at the applicable rate allowed under the law.

As such, during the 2022 ceiling price development process, SEA interpreted this statute to mean that REG facilities, post-tariff, would be entitled to compensation for production at the applicable net metering rate.

Given this, SEA incorporated a discounted post-tariff revenue stream into the CREST model starting after the end of the tariff term and continuing through the end of the project's useful life. The 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. The resulting revenue stream was sufficient to cover post-tariff operating expenses for all project types.

Please describe the issues raised during the 2023 ceiling prices development process regarding post-tariff revenue assumptions.

During the 2023 ceiling price development process, a specific group of market participant stakeholders argued that in order to participate in the net metering program post-tariff, projects would have to undergo reconfiguration from a front-of-the-meter (FTM) facility to a behind-the-meter (BTM) facility. Stakeholders argued that such reconfiguration was costly and would require re-study of the project's interconnection at the utility, introducing (they argued) a 12-16 month delay in the project's operation.

Based on the issues raised during the stakeholder process, does SEA believe that the Renewable Energy Growth Act, as written, provides sufficient clarity regarding what to assume regarding post-tariff revenue?

No, we do not. The central issue that SEA desires clarification on from the PUC is if R.I.G.L. § 39-26.6-23 entitles REG projects to compensation for production at the applicable net metering rate post tariff <u>without</u> requiring project re-configuration. If the answer is no, we will assume that projects would have to reconfigure if they wish to receive net metering credits, and thus the project's owners would have to reassess whether to continue to operate the project after the end of the tariff term.

How does SEA propose to address the uncertainty regarding the appropriate interpretation of statute?

Our role in the REG ceiling price development process is not to interpret policy. As such, we have provided the PUC with two sets of ceiling prices which reflect the appropriate ceiling price under either interpretation of statue so that the PUC may select the ceiling price that best conforms with its interpretation of statute. SEA expresses no preference between these two options.

If the PUC believes that R.I.G.L. § 39-26.6-23 entitles REG projects to compensation for production at the applicable net metering rate without reconfiguration, it should select the "Including Post-Tariff Revenue" set of recommended prices, and if not, it should select the "Excluding Post-Tariff Revenue."

Please describe the two options for the prices SEA requests that the PUC select between, and the assumptions underlying each option.

The ceiling prices provided in the "Including Post-Tariff Revenue" set include discounted net metering post-tariff revenue starting after the end of the tariff term and continuing through the end of the project's useful life. This set of prices assumes that REG projects are entitled to compensation for production at the applicable net metering rate post tariff without re-configuration. As such, no re-configuration costs are included in modeling at the end of the tariff term.

The ceiling prices provided in the "Excluding Post-Tariff Revenue" set do not include any post-tariff revenue. As such, the term of the analysis is limited to only the duration of the tariff, as extending the analysis through the end of the project's assumed useful life would result in the project operating at a loss post-tariff (given the presence of post-tariff operating expenses and a lack of sufficient post-tariff revenue) and thereby would raise the calculated ceiling prices. The selection of Option Two is not meant to preclude real-world REG projects from operating beyond the duration of the tariff and obtaining post-tariff revenue. Rather, the "Excluding Post-Tariff Revenue" set is the result of modeling that assumes the project's operation through the end of the tariff period (and thus, the investors' realization of the target return by the end of the tariff period). Importantly, this set of prices is also predicated on the assumption that project owners will make an informed decision regarding the economics of continuing to operate the project based on the available post-tariff revenue at the conclusion of the tariff period. Consistent with the "Including Post-Tariff Revenue" set of prices, no re-configuration costs are included in modeling at the end of the tariff term.

Why does SEA believe it is inappropriate to model an approach where project reconfiguration is assumed at or immediately prior to the end of the project's REG tariff term to allow for net metering participation?

We intend for the assumptions embedded in the calculation of ceiling prices to reflect practices that the average project can achieve with reasonable certainty. We believe that the real-world uncertainties regarding project reconfiguration, including any added costs or delays introduced by any requirements (if such were to be in place at the time) of re-study by Narragansett Electric and the availability of on-site load, are sufficiently significant to exclude reconfiguration as a practice that can be achieved with reasonable certainty. In general, we believe that requiring projects to modify their initial electrical configuration in order to be economically viable under the calculated ceiling prices introduces an undue degree of uncertainty and may represent a slippery slope to over-optimizing the modeled project at the expense of real-world outcomes.

Why are some of the recommended ceiling prices unchanged between the two options put before this Commission?

For the Medium Solar and the Community Remote - Commercial Solar >250-500 kW renewable energy classes, the difference between the two options appears identical because the difference between the two options in the CREST model approaches zero. The reason that the difference is appears to be zero is that the difference between the project's expected post-tariff revenues being extremely (and coincidentally) close to the project's post-tariff operating costs. As a result of this, and the time value of money, the differences are so highly discounted that the difference rounds to the same exact number.

For AD, these projects are only assumed to have a 20-year life, and thus are not assumed to have a post-tariff operating period.

Why did SEA choose not to model an option in which post-tariff revenue is assumed to be the combination of forecasted wholesale energy and RECs?

Given that the statutory issue at hand regards the availability of net metering revenue, we tested a case in which wholesale energy and REC revenue were modeled post-tariff. However, we found that, for all project types, wholesale energy and REC revenue was unable to cover operating expenses post-tariff. As such, the inclusion of such revenue, and the resulting extension of the term of the analysis beyond the tariff period, raised ceiling prices for all project types.

Are OER and the DG Board requesting a declaratory ruling on this issue?

No. However, given that the version of the 2023 program year ceiling prices must reflect a reasonable interpretation of state law, SEA, on behalf of OER and the DG Board, respectfully requests that the PUC select the version of the ceiling prices that best aligns with its interpretation of R.I.G.L. § 39-26.6-23.

<u>Small Solar I Tax Treatment</u>

During the 2023 ceiling price development process did SEA change its taxation assumptions for Small Solar I projects?

Yes, we did.

Did SEA receive feedback from the DPUC regarding these assumptions during the 2022 ceiling price development processes? If so, please summarize this feedback.

Yes, we did. The DPUC argued that, for Small Solar I, SEA should not assume that the performance-based incentive is taxable income, siting the tax policy guidance that National Grid publishes on this matter that states that bill credits provided to residential customers will not be reported as income.

How did SEA address this feedback during the 2022 ceiling price development process?

We agreed that bill credits should not be taxable income, but also found that a portion of the performance-based incentives were disbursed to residential customers as cash payments, which would be considered taxable income. Lacking data on the average percentage of performance-based incentives that were taxable, we continued to use our assumed rate of 65% in setting the 2022 program year prices, which the Commission approved.

Did SEA also receive feedback from the PUC regarding these assumptions during the public hearing for the 2022 program year ceiling prices?

Yes.

Please summarize this feedback.

The PUC agreed with the Division that bill credits should not be assumed taxable income, and requested that SEA substantiate the assumed taxable share of the performance-based incentives during the 2023 ceiling price development process. In addition, the PUC requested that SEA substantiate the assumed effective tax rate for Small Solar I during the 2023 ceiling price development process.

During the 2023 ceiling price development process, did SEA adopt the changes sought by the DPUC, and incorporate the PUC's feedback?

Yes, we did.

Please describe SEA's methodology for making the DPUC's requested changes.

To substantiate the percent of the performance-based incentive assumed taxable, we received data from Rhode Island Energy containing 1,790 months of billing information from customers selected for REG quality assurance inspections. An analysis of these billing data revealed that the average customer received 52% of their performance-based incentive through cash payments (as opposed to bill credits). The analysis and supporting (anonymized) data are provided as **SEA Schedule 18**. As a result, we updated the percent of the performance-based incentive assumed taxable from 65% to 52% for the calculation of the 2023 ceiling prices.

To substantiate the effective tax rate for residential customers, SEA relied on analysis of Rhode Island solar adoption conducted by the Lawrence Berkley National Laboratory, which found that solar adopters income was, on average, 150% of the county median. SEA then used county-level Census data, to calculate a household-adjusted median statewide income of $70,812, which suggests household income is $106,218 for the average solar adopter. Finally, using 2022-23 marginal tax rate thresholds from the IRS, SEA calculated that a married couple filing jointly with the above adjusted gross income would have an effective tax rate of 14%. As a result, SEA updated the assumed effective tax rate from 26% to 14%.

Do you believe that these changes appropriately address the DPUC and PUC's feedback?

Yes, we do.

<u>**Reasonableness of 2023 Recommended Ceiling Prices**</u>

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

Yes. We believe that the recommended ceiling prices represent an effective balance among all the policy objectives of Rhode Island law.

Does SEA believe that the ceiling prices approved by the DG Board on November 14, 2022 and recommended to the Commission are reasonable and are in the best interests of the State of Rhode Island and meet the renewable program's goals and objectives?

Yes.

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

Yes.

Does SEA believe that the ceiling price development process used for the 2023 REG program was consistent with all prior years in which the PUC has approved the Ceiling Prices?

Yes.

Does this conclude your testimony?

Yes.

SEA Schedule 1 - SEA First Stakeholder Meeting Presentation

See file named: SEA Schedule 1 – SEA First Stakeholder Meeting Presentation.pdf

SEA Schedule 2 – SEA Second Stakeholder Meeting Presentation

See file named: SEA Schedule 2 – SEA Second Stakeholder Meeting Presentation.pdf

<u>SEA Schedule 3 – SEA Third Stakeholder Meeting Presentation</u>

See file named: SEA Schedule 3 – SEA Third Stakeholder Meeting Presentation.pdf

SEA Schedule 4 – SEA Fourth Stakeholder Meeting Presentation

See file named: SEA Schedule 4 – SEA Fourth Stakeholder Meeting Presentation and Technical Correction.pdf

SEA Schedule 5 – Total Number of Stakeholder Responses to Data Requests and Surveys

Total Number of Stakeholder Responses to Data Requests and Surveys by Category		
Technology	Total Stakeholder Responses Submitted by Category	
	Initial Data Request and Survey	Follow-up Stakeholder Calls
Solar	3	4
Non-Solar	1	1
Solar/Non-Solar	1	1

<u>SEA Schedule 6 - Initial Data Request and Survey for 2023 Ceiling Price Process</u>

See file named: SEA Schedule 6 - Initial Data Request and Survey for 2023 Ceiling Price Process.pdf

SEA Schedule 7 – DPUC Comments on First Draft Ceiling Prices

See file named: SEA Schedule 7 – DPUC Comments on First Draft Ceiling Prices.pdf

<u>SEA Schedule 8 – DPUC Comments on Second Draft Ceiling Prices</u>

See file named: SEA Schedule 8 – DPUC Comments on Second Draft Ceiling Prices.pdf

SEA Schedule 9 – 2023 Proposed Renewable Energy Classes and Eligible System Sizes

2023 Proposed Renewable Energy Classes and Eligible System Sizes	
Renewable Energy Class	**Eligible System Sizes**
Small Solar I	0-15 kW_{DC}
Small Solar II	>15-25 kW_{DC}
Medium Solar I	>25-150 kW_{DC}
Medium Solar II	>150-250 kW_{DC}
Commercial Solar I	>250-500 kW_{DC}
Commercial Solar II	>500- 1000 kW_{DC}
Large Solar	>1-5 MW_{DC}
Wind	≤ 5 MW_{AC}
Anaerobic Digestion	≤ 5 MW_{AC}
Small Scale Hydropower	≤ 5 MW_{AC}
Community Remote – Commercial Solar	>250-500 kW_{DC}
	>500-1000 kW_{DC}
Community Remote – Large Solar	>1-5 MW_{DC}
Community Remote – Wind	≤ 5 MW_{AC}

SEA Schedule 10 – 2023 Proposed Ceiling Prices, Eligible System Sizes and Tariff Terms

2023 Proposed Ceiling Prices, Eligible System Sizes and Tariff Terms				
Renewable Energy Class	Tariff Term (Years)	Eligible System Size	Ceiling Price (¢/kWh)	
			Including Post-Tariff Revenue	Excluding Post-Tariff Revenue
Small Solar I	15	0-15 kW_{DC}	27.75	31.25
Small Solar II	20	>15-25 kW_{DC}	26.15	26.65
Medium Solar	20	>25-250 kW_{DC}	25.65	25.65
Commercial Solar I	20	>250-500 kW_{DC}	22.05	22.35
Commercial Solar II	20	>500-1000 kW_{DC}	19.05	19.55
Community Remote – Commercial Solar	20	>250-500 kW_{DC}	25.15	25.15
		>500-1000 kW_{DC}	21.91	22.35
Large Solar	20	>1-5 MW_{DC}	14.35	15.45
Community Remote – Large Solar	20	>1-5 MW_{DC}	16.50	17.77
Wind	20	≤ 5 MW_{AC}	19.15	19.95
Community Remote – Wind	20	≤ 5 MW_{AC}	21.15	21.75
Anaerobic Digestion	20	≤ 5 MW_{AC}	19.05	19.05
Small Scale Hydropower	20	≤ 5 MW_{AC}	31.95	32.45

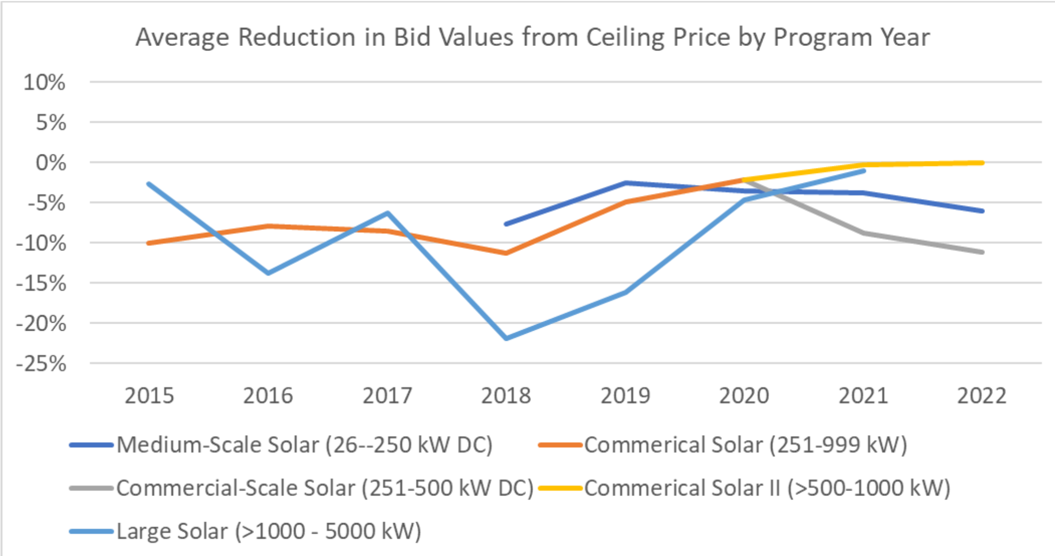
SEA Schedule 11 – Percentage Change from 2022 Approved to 2023 Proposed REG Ceiling Prices

Percentage Change from 2022 Approved to 2023 Proposed REG Ceiling Prices			
Category	**Eligible System Size**	**% Change (2022-2023), Including Post-Tariff Revenue**	**% Change (2022-2023), Excluding Post-Tariff Revenue**
Small Solar I	0-15 kWDC	-11%	1%
Small Solar II	>15-25 kWDC	-5%	-3%
Medium Solar	>25-250 kWDC	5%	5%
Commercial Solar I	>250-500 kWDC	15%	16%
Commercial Solar II	>500-1000 kWDC	21%	24%
Community Remote – Commercial Solar	>250-500 kWDC	14%	14%
	>500-1000 kWDC	21%	23%
Large Solar	>1-5 MWDC	31%	41%
Community Remote – Large Solar	>1-5 MWDC	31%	41%
Wind	≤ 5 MWAC	-15%	-11%
Community Remote –Wind	≤ 5 MWAC	-14%	-12%
Anaerobic Digestion	≤ 5 MWAC	-25%	-25%
Small Scale Hydropower	≤ 5 MWAC	-14%	-13%

SEA Schedule 12 – Percentage Change in Upfront Capital Costs for Selected Proxy Solar Projects from 2022 Approved to 2023 Proposed REG Ceiling Prices

	Recommended 2023 Ceiling Prices (IRA changes included)		2023 Ceiling Prices with IRA changes removed		Percent Change (IRA vs non-IRA)	
Post-tariff Revenue Case Resource Class	Excluding Post-tariff Revenue	Including Post-tariff Revenue	Excluding Post-tariff Revenue	Including Post-tariff Revenue	Excluding Post-tariff Revenue	Including Post-tariff Revenue
Small Solar I	31.25	27.75	35.95	31.95	-13.1%	-13.1%
Small Solar II	26.65	26.15	29.55	28.95	-9.8%	-9.7%
Medium Solar	25.65	25.65	28.45	28.35	-9.8%	-9.5%
Commercial Solar I	22.35	22.05	24.25	24.05	-7.8%	-8.3%
Commercial Solar I (CRDG)	25.15	25.15	27.25	27.15	-7.7%	-7.4%
Commercial Solar II	19.55	19.05	21.35	20.95	-8.4%	-9.1%
Commercial Solar II (CRDG)	22.35	21.91	24.35	24.05	-8.2%	-8.9%
Large Solar	15.45	14.35	17.35	16.15	-11.0%	-11.1%
Large Solar (CRDG)	17.77	16.50	19.95	18.57	-11.0%	-11.1%
Wind	19.95	19.15	24.75	23.95	-19.4%	-20.0%
Wind (CRDG)	21.75	21.15	26.75	26.25	-18.7%	-19.4%
Hydro	32.45	31.95	39.05	38.65	-16.9%	-17.3%
Anerobic Digestion	19.05	19.05	26.15	26.15	-27.2%	-27.2%

SEA Schedule 13 – Comparison of Ceiling Prices to Average Bid Prices by Program Year



Notes:

- Prior to 2018, the Medium Solar class was not subject to a competitive procurement.
- No eligible Large Solar bids were received during the 2022 program year at the time the graphic was created (pre-third Open Enrollment).
- The Commercial Solar class was bifurcated in 2021.

SEA Schedule 14 – Adjustments to Installed Cost Inputs

Category	2022 Adopted YoY Project Cost Factor[5]	2023 Recommended YoY Project Cost Factor[6]
Small Solar I / II	2%	-1.6%
Medium Solar, Commercial Solar, Comm. Solar CRDG	4%	-0.8%
Large Solar, Large Solar CRDG	5%	-0.2%

[5] Represents "Moderate" 2021 NREL ATB Case with adjustments based on the EIA Short Term Energy Outlook
[6] Represents "Conservative" 2022 NREL ATB Case

SEA Schedule 15 – Percentage Change in Upfront Capital Costs for Selected Proxy Solar Projects from 2022 Approved to 2023 Proposed REG Ceiling Prices

Percentage Change in Upfront Capital Costs for Selected Proxy Solar Projects from 2022 Approved to 2023 Proposed REG Ceiling Prices				
Category	**Eligible System Size(s)**	**2022 Approved**	**2023 Proposed**	**% Change**
Small Solar I	0-15 kWDC	$3,377	$3,566	5.6%
Small Solar II	>15-25 kWDC	$3,103	$3,058	-1.5%
Medium Solar	>25-250 kWDC	$2,408	$2,485	3.2%
Commercial Solar I	>250-500 kWDC	$2,108	$2,352	11.6%
Commercial Solar II	>500-1000 kWDC	$1,938	$2,218	14.4%
Large Solar	>1-5 MWDC	$1,444	$1,964	36.0%

SEA Schedule 16 – Calculation of Interest Rate on Term Debt

Row ID	Row Label	Notes	Medium Solar	Comm'l Solar/ Comm'l CRDG	Large Solar/ Large CRDG	Wind/ Wind CRDG	AD	Small-Scale Hydro
A	Debt Term (Years)	Med. & Comm'l = average of 10 and 15 year values	13	13	15	15	15	20
B	10-Year Treasury Yield	Value on 10/10/2022	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
C	20-Year Treasury Yield	Value on 10/10/2022	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%
D	Effective 15-Year Treasury Value (for Swap)	Avg of B & C	4.09%	4.09%	4.09%	4.09%	4.09%	4.09%
E	Effective 13-Year Treasury Value (for Swap)	Avg of B & D	4.04%	4.04%	4.04%	4.04%	4.04%	4.04%
F	Applicable Treasury-Based Value	Based on A	4.04%	4.04%	4.09%	4.09%	4.09%	4.09%
G	Risk Premium	Per stakeholder term sheet	3.25%	3.25%	3.25%	3.50%	3.25%	3.50%
H	**Estimate of Interest Rate on Term Debt**	**F + G**	**7.29%**	**7.29%**	**7.34%**	**7.59%**	**7.34%**	**7.59%**

<u>SEA Schedule 17 – Comparison of 2021 Approved and 2022 Proposed National Grid- Supplied Distribution Interconnection Costs for Projects Larger than 25 kWDC</u>

Comparison of 2022 Approved and 2023 Proposed Rhode Island Energy-Supplied Distribution Interconnection Costs for Projects Larger than 25 kWDC			
Renewable Energy Class	**Eligible System Size**	**IC $/kWDC (2022 Approved Prices)**	**IC $/kWDC (2023 Recommended Prices)**
Medium Solar[7]	25-250 kWDC	$187	$162
Commercial Solar	251-1000 kWDC	$114	$149
Large Solar	1-5 MWDC	$173	$250
Wind	0-5 MWAC	$295	$295

[7] We assume interconnection is a relatively small fee per unit of capacity for Small Solar projects, and thus included in the purchase price for these projects. As such, we do not have a separate interconnection cost estimate for these projects.

<u>SEA Schedule 18 – Small Solar Tax Analysis</u>

See file named: SEA Schedule 18 – Small Solar Tax Analysis