STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: THE RHODE ISLAND DISTRIBUTED	:	
GENERATION BOARD'S RECOMMENDATIONS	:	
FOR THE 2022 RENEWABLE ENERGY	:	DOCKET NO. 5202
GROWTH PROGRAM YEAR 2022	:	

Recommendations for the 2022 Renewable Energy Growth Program Year

DISTRIBUTED-GENERATION BOARD
& OFFICE OF ENERGY RESOURCES

DECEMBER 15, 2021

Table of Contents

DISTRIBUTED GENERATION BOARD

2022 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 2022 Renewable Energy Growth Program Year ("RE Growth 2022 PY") to the Public Utilities Commission ("Commission" or "PUC"). The recommendations set forth herein, regarding classes, tariff term lengths, ceiling prices and 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 2022 PY are the following:

- A diversified renewable energy program with a portion of the megawatt

("MW") capacity allocated to support each sector.

- When appropriate, continued decreases in ceiling prices in certain renewable energy classes.
- Economic development with the State's renewable energy market.
- 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 The Narragansett Electric Company d/b/a National Grid ("National Grid").

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**
Nicholas Ucci	OER Commissioner (ex officio, non-voting)
Ian Springsteel	National Grid (ex officio, non-voting)
Vacant	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
Vacant	Residential users
Vacant	Low income users
Sheila Dormody	Environmental issues pertaining to energy
Laura C.H. Bartsch (Chair)	Construction of renewable generation

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 2022 PY.

The changes between the approved classes for the 2021 PY and the recommended classes for the 2022 PY are illustrated in **Table 2B** below. The specific changes by class are marked in red.

Table 2A - Recommended Renewable Energy Classes 2022 PY

Renewable Energy Class	Eligible System Sizes
Small Solar I	1-15 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	$\leq$ 5 MW_{AC}
Anaerobic Digestion	$\leq$ 5 MW_{AC}
Small Scale Hydropower	$\leq$ 5 MW_{AC}
Community Remote – Commercial Solar	>250-750 kW_{DC}
Community Remote – Commercial Solar	>750-1000 kW_{DC}
Community Remote – Large Solar	>1-5 MW_{DC}
Community Remote – Wind	$\leq$ 5 MW_{AC}

Table 2B – Renewable Energy Classes: Approved 2021 PY vs Recommended 2022 PY	
PUC Approved 2021 PY	**DG Board Recommended 2022 PY**
Small Solar I (1-15 kW_{DC})	Small Solar I (1-15 kW_{DC})
Small Solar II (15-25 kW_{DC})	Small Solar II (>15-25 kW_{DC})
Medium Solar (26-250 kW_{DC})	Medium Solar I **(>25-150 kW_{DC})**
	Medium Solar II **(>150-250 kW_{DC})**
Commercial Solar I(251 kW–750 kW_{DC})	Commercial Solar I (**>250 kW–500 kW_{DC}**)
Commercial Solar II (751 kW–999 kW_{DC})	Commercial Solar II (**>500 kW–1,000 kW_{DC}**)
Large Solar (1-5 MW_{DC})	Large Solar (>1-5 MW_{DC})
Wind (≤ 5 MW_{AC})	Wind (≤ 5 MW_{AC})
Anaerobic Digestion (≤ 5 MW_{AC})	Anaerobic Digestion (≤ 5 MW_{AC})
Small Scale Hydropower (≤ 5 MW_{AC})	Small Scale Hydropower (≤ 5 MW_{AC})
Community Remote – Commercial Solar (251-750 kW_{DC})	Community Remote – Commercial Solar (**>250-500 kW_{DC}**)
Community Remote – Commercial Solar (751–999 kW_{DC})	Community Remote – Commercial Solar (**>500-1000 kW_{DC}**)
Community Remote – Large Solar (1-5 MW_{DC})	Community Remote – Large Solar (>1-5 MW_{DC})
Community Remote – Wind (≤5 MW_{AC})	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 2022 PY.

Table 3A – Recommended Tariff Lengths 2022 PY	
Renewable Energy Class	**Tariff Length**
Small Solar I (0-15 kW_{DC})	15 Years
Small Solar II (>15-25 kW_{DC})	20 Years
Medium Solar I (>25-150 kW_{DC})	20 Years
Medium Solar II (>150-250 kW_{DC})	20 Years
Commercial Solar I (>250 kW_{DC}–500 kW_{DC})	20 Years
Commercial Solar II (>500 kW_{DC}–1,000 kW_{DC})	20 Years
Large Solar (>1-5 MW_{DC})	20 Years
Wind (≤ 5 MW_{AC})	20 Years
Anaerobic Digestion (≤ 5 MW_{AC})	20 Years
Small Scale Hydropower (≤ 5 MW_{AC})	20 Years
Community Remote – Commercial Solar I (>250 kW_{DC}–500 kW_{DC})	20 Years
Community Remote – Commercial Solar II (>500 kW_{DC}–1,000 kW_{DC})	20 Years
Community Remote – Large Solar (>1-5 MW_{DC})	20 Years
Community Remote – Wind (≤ 5 MW_{AC})	20 Years

Ceiling Prices

Consistent with R.I. Gen. Laws § 39-26.6-5(d) and § 39-26.2-5, please see **Table 4A** below, which contains the DG Board's recommendations for ceiling prices for the RE Growth 2022 PY. The changes between the approved ceiling prices for the 2021 PY and the recommended ceiling prices for the 2022 PY are illustrated in **Table 4B** below. For additional information, please see the pre-filed testimony and schedules of Jim Kennerly, SEA, (Pages 19-39; 40-59).

Ceiling price trends from 2011-2022 are illustrated in **Table 4C** (Solar), **Table 4D** (Wind), **Table 4E** (Anaerobic Digestion), and **Table 4F** (Hydropower) below.

Table 4A - Recommended Ceiling Prices 2022 PY

Renewable Energy Class	Ceiling Price (¢/kWh)
Small Solar I (0-15 kW_{DC})	31.05
Small Solar II (>15-25 kW_{DC})	27.55
Medium Solar I (>25-150 kW_{DC})	26.65
Medium Solar II (>150-250 kW_{DC})	24.45
Commercial Solar I (>250 kW_{DC}–500 kW_{DC})	19.25
Commercial Solar II (>500 kW_{DC}–1,000 kW_{DC})	15.75
Large Solar (>1-5 MW_{DC})	10.95
Wind (≤ 5 MW_{AC})	22.40
Anaerobic Digestion (≤ 5 MW_{AC})	25.55
Small Scale Hydropower (≤ 5 MW_{AC})	37.15
Community Remote – Commercial Solar I (>250 kW_{DC}–500 kW_{DC})	22.14
Community Remote – Commercial Solar II (>500 kW_{DC}–1,000 kW_{DC})	18.11
Community Remote – Large Solar (>1-5 MW_{DC})	12.59
Community Remote – Wind (≤ 5 MW_{AC})	24.60

Table 4B – Ceiling Prices: Approved 2021 PY vs Recommended 2022 PY			
Renewable Energy Class	**DG Board Recommended 2022 PY**	**PUC Approved 2021 PY**	**% Change between 2021 PY and 2022 PY**
Small Solar I (0-15 kW_{DC})	31.05	28.75	8.0%
Small Solar II (>15-25 kW_{DC})	27.55	24.35	13.0%
Medium Solar I (>25-150 kW)	26.65	N/A[1]	N/A
Medium Solar II (>150-250 kW)	24.45	N/A[2]	N/A
Commercial Solar I (>250 kW_{DC}–500 kW_{DC})	19.25	18.55[3]	4.0%
Commercial Solar II (>500 kW_{DC}–1,000	15.75	15.25[4]	3.0%
Large Solar (>1-5 MW_{DC})	10.95	11.35	-4.0%
Wind (≤ 5 MW_{AC})	22.40	18.75	19.0%
Anaerobic Digestion (≤ 5 MW_{AC})	25.55	15.85	61.0%
Small Scale Hydropower (≤ 5 MW_{AC})	37.15	27.35	36.0%
Community Remote – Commercial Solar I (>250 kW_{DC}–500 kW_{DC})	22.14	21.33	4.0%
Community Remote – Commercial Solar II (>500 kW_{DC}–1,000 kW_{DC})	18.11	17.54	3.0%
Community Remote – Large Solar (>1-5 MW_{DC})	12.59	13.05	-4.0%
Community Remote – Wind (≤ 5 MW_{AC})	24.60	21.05	17.0%

[1] There was previously just one Medium Solar class for the 2021 program year, which ranged from 25 kW_{DC} or greater to less than or equal to 250 kW_{DC}

[2] See Footnote 1

[3] The previous "small commercial" category bin size for the 2021 program year was 251-750 kW_{DC}

[4] The previous "large commercial" category bin size for the 2021 program year was 751-999 kW_{DC}

Table 4C - Ceiling Price Trend for Solar

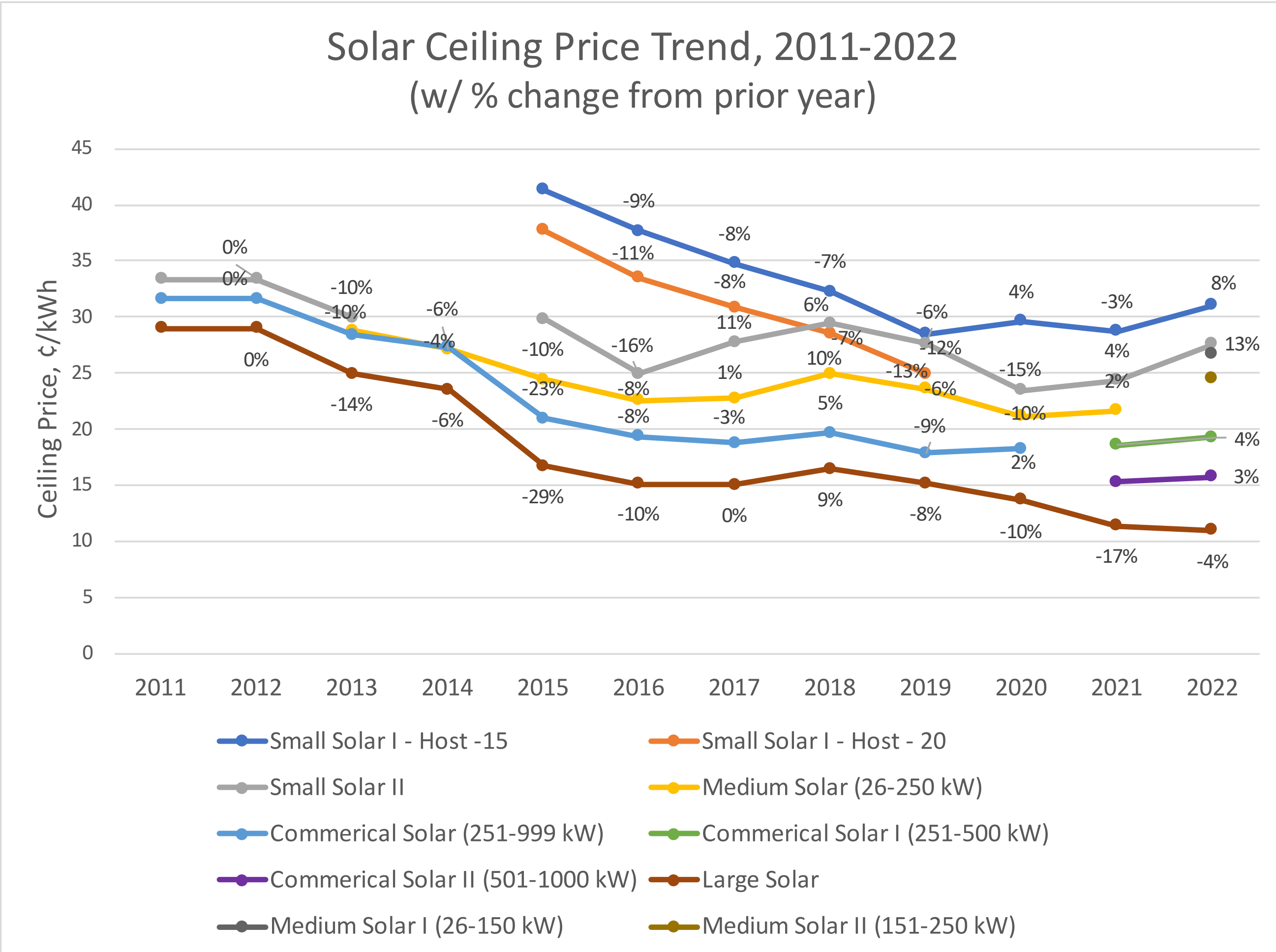


Table 4D - Ceiling Price Trend for Wind

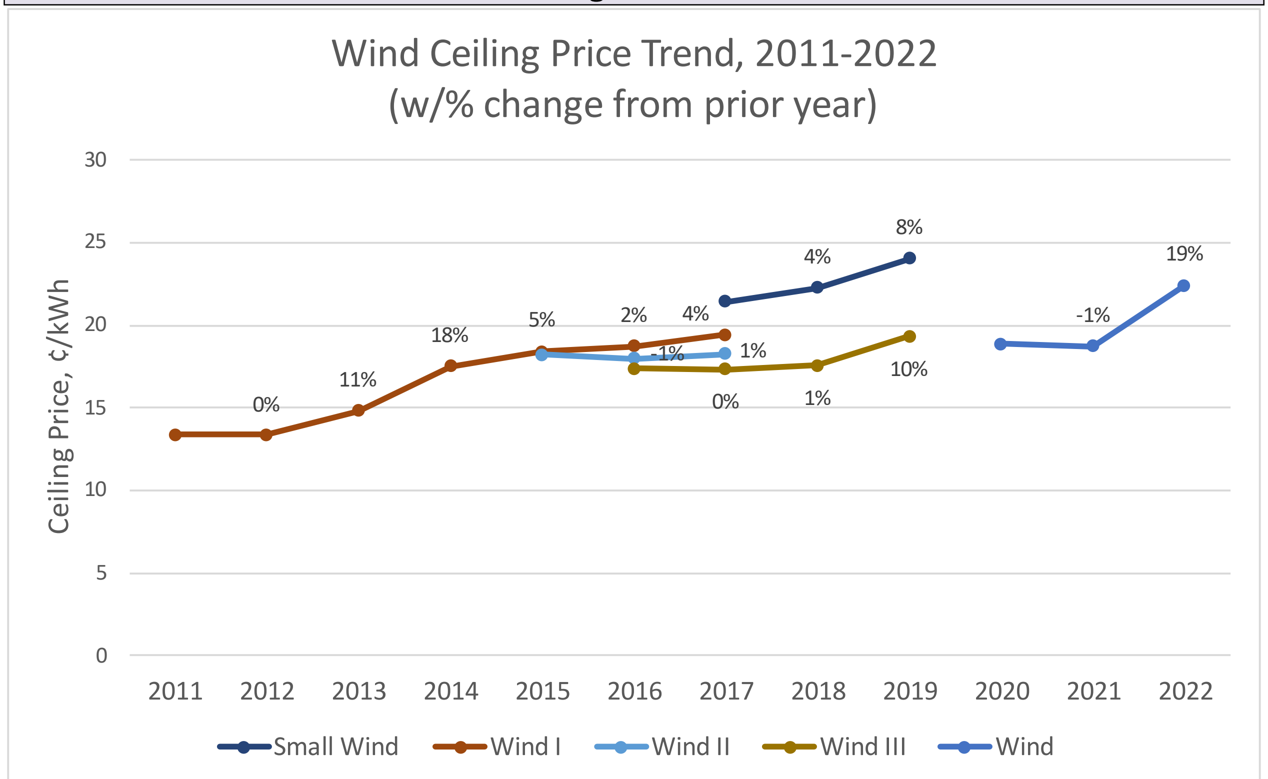


Table 4E - Ceiling Price Trend for Anaerobic Digestion

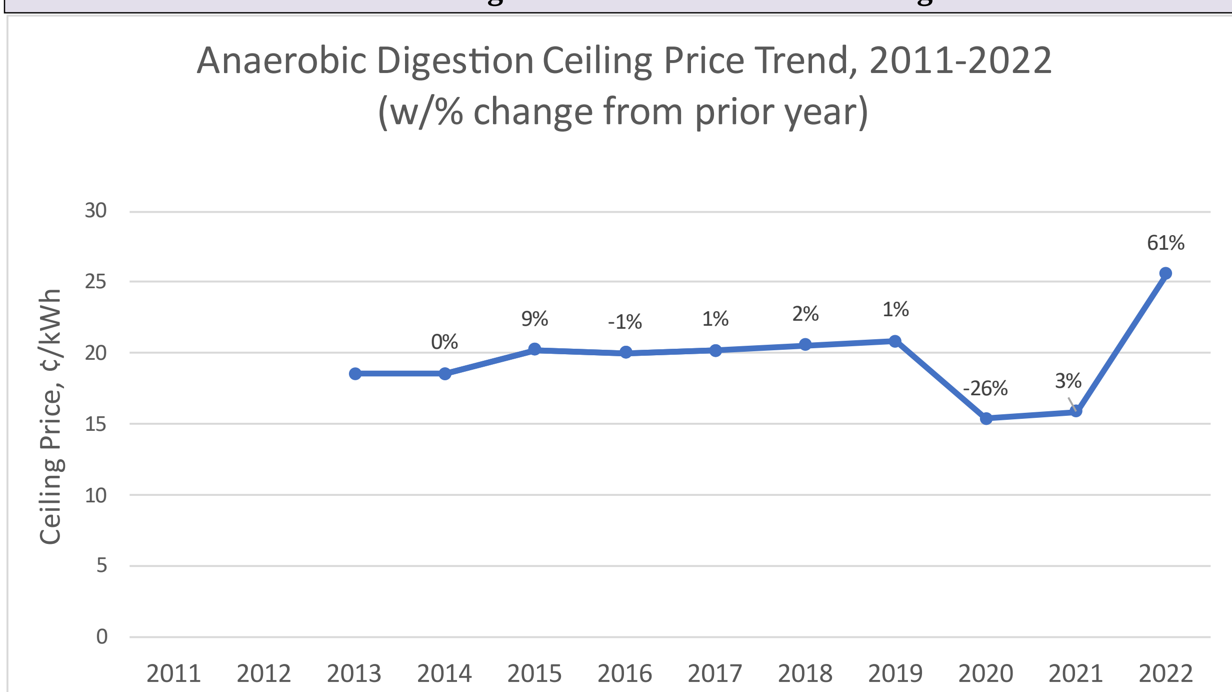
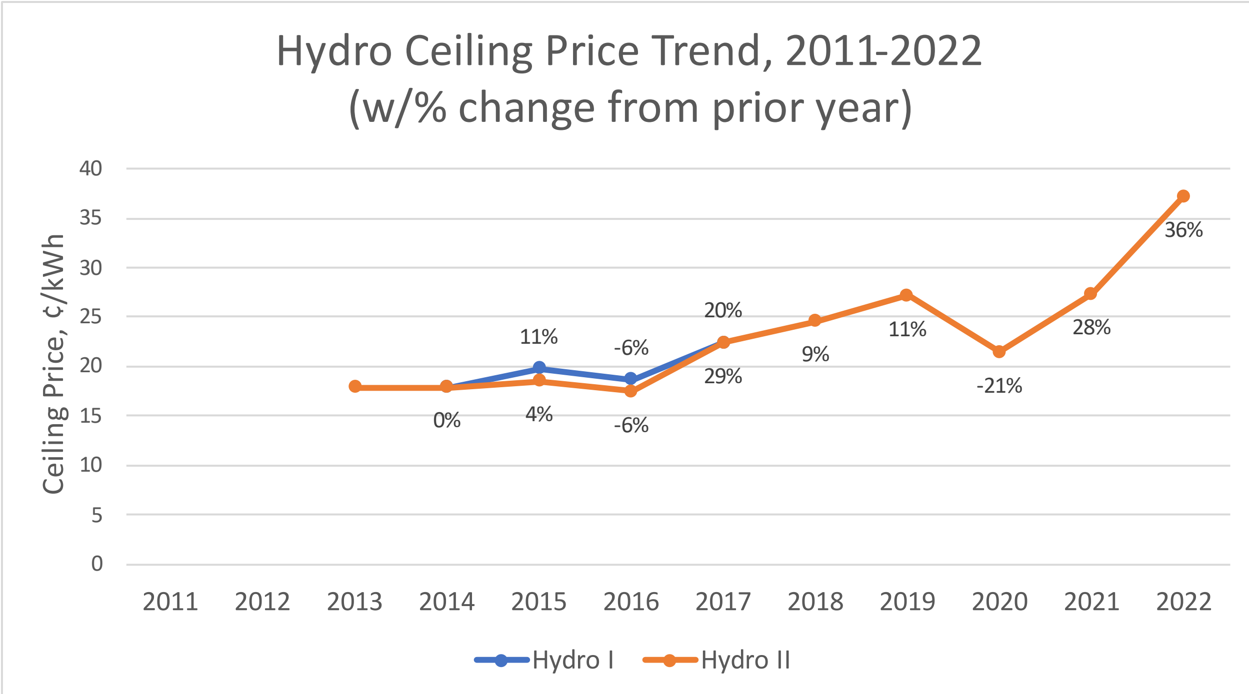


Table 4F - Ceiling Price Trend for Hydropower



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 2022 PY. The changes between the approved allocation plan for the 2021 PY and the recommended allocation plan for the 2021 PY are illustrated in **Table 5B** below. The total megawatt number reflects the annual megawatt capacity (40 megawatts) for the RE Growth 2022 PY in addition to any unused or terminated megawatt capacity (21.2 megawatts as of October 2021) from the RE Growth 2017-2020 PYs.

Table 5C below contains the recommended allocation for the first commercial enrollment for the RE Growth PY 2022.

Table 5A - Recommended Allocation Plan 2022 PY	
Renewable Energy Class	**Allocation (MW)**
Small Solar I & II	6.950
Medium Solar I (>25-150 kW)	2.5
Medium Solar II (>150-250 kW)	2.5
Commercial Solar I (>250-500 kW)	4.0
Commercial Solar II (>500-999 kW)	8.0
Large Solar (>1-5 MW_{DC})	24.25
Wind (≤ 5 MW_{AC})	3.0
Community Remote – Wind (≤ 5 MW_{AC})	
Anaerobic Digestion (≤ 5 MW_{AC})	1.0
Small Scale Hydropower (≤ 5 MW_{AC})	
Community Remote – Commercial (>250-500 kW)	3.0
Community Remote – Commercial (>500-999 kW)	3.0
Community Remote – Large Solar (>1-5 MW_{DC})	3.0
Total	**61.2**

Table 5B – Allocation Plan: Approved PY 2021 vs Recommended PY 2022			
Renewable Energy Class	**DG Board Recommended PY 2022 (MW)**	**DG Board Recommended and PUC Approved 2021 PY**	**Change between 2021 PY and 2022 PY (%)**
Small Solar I & II	6.950	6.950	0%
Medium Solar I (>25-150 kW_{DC})	2.5	5.0	0%
Medium Solar II (>150-250 kW_{DC})	2.5		0%
Commercial Solar I (>250-500 kW_{DC})	4.0	4.0	0%
Commercial Solar II (>500-999 kW_{DC})	8.0	8.0	0%
Large Solar (>1-5 MW_{DC})	24.25	22.897	6%
Wind (≤ 5 MW_{AC})	3.0	3.0	0%
Community Remote – Wind (≤ 5 MW_{AC})			
Anaerobic Digestion (≤ 5 MW_{AC})	1.0	1.0	0%
Small Scale Hydropower (≤ 5 MW_{AC})			
Community Remote – Commercial (>250-500 kW_{DC})	3.0	3.0	0%
Community Remote – Commercial (>500-999 kW_{DC})	3.0		0%
Community Remote – Large Solar (>1-5 MW_{DC})	3.0	3.0	0%
Total	**61.2**	**56.847**	

Table 5C - Recommended Allocation Plan for First Enrollment 2022 PY	
Renewable Energy Class	**Allocation (MW)**
Small Solar I & II	6.950
Medium Solar I (>25-150 kW$_{DC}$)	2.5
Medium Solar II (>150-250 kW$_{DC}$)	2.5
Commercial Solar I (>250-500 kW$_{DC}$)	4.0
Commercial Solar II (>500-999 kW$_{DC}$)	8.0
Large Solar (>1-5 MW$_{DC}$)	24.25
Wind (≤ 5 MW$_{AC}$)	3.0
Community Remote – Wind (≤ 5 MW$_{AC}$)	
Anaerobic Digestion (≤ 5 MW$_{AC}$)	1.0
Small Scale Hydropower (≤ 5 MW$_{AC}$)	
Community Remote – Commercial (>250-500 kW$_{DC}$)	3.0
Community Remote – Commercial (>500-999 kW$_{DC}$)	3.0
Community Remote – Large Solar (>1-5 MW$_{DC}$)	3.0
Total	**61.2**

* Any additional megawatt capacity that remains unused from the RE Growth 2021 PY Small Solar Class (closes on March 31, 2022) would be allocated to the 2022 RE Growth PY Small Solar Class.

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

Non-Continuation of Solar Carport Adder Pilot

In February 2021, the PUC approved the continuation of the Carport adder pilot applicable to projects in the 2021 Program Year at a rate of 5.0 cents/kWh. In its Order approving the continuation of the Carport Adder Pilot, the PUC also directed OER and the DG Board to update its report on lessons learned from the Pilot (relative to the initial assessment conducted in support of the initial pilot launch for the 2020 Program Year), including an assessment of the public policy benefits of the Pilot. OER and the DG Board engaged SEA, together with its subcontractor Mondre Energy ("Mondre"), to update its previous analysis evaluating the Carport Adder. The Consulting Team's (SEA and Mondre) evaluation report collected updated information on the costs and benefits of solar carport projects and included an updated cost-benefit analysis of the Carport Adder. This subject will be discussed in greater detail in the testimony of Jason Gifford, SEA (Pages 60-67).

Conclusion

After an extensive and transparent development process, the DG Board voted at its October 26, 2021 meeting to approve the recommendations set forth herein. The DG Board and OER respectfully request the PUC to approve such recommendations for the RE Growth 2022 PY.

<u>Pre-Filed Direct Testimony of Jim Kennerly – Sustainable Energy Advantage</u>

I, Jim Kennerly, hereby testify under oath as follows:

Please state your name, employer and title.

My name is Jim Kennerly. I am employed by Sustainable Energy Advantage, LLC ("SEA") as Director and Policy Analytics Practice Lead.

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 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 New Jersey Board of Public Utilities ("NJ BPU"), the Massachusetts Clean Energy Center ("MassCEC"), the New York State Energy Research and Development Authority ("NYSERDA"), the Connecticut Public Utility Regulatory Authority ("CT PURA"), the New Hampshire Office of Consumer Advocate ("NH OCA"), the Massachusetts Attorney General's Office ("MA AG"), the Connecticut Green Bank ("CGB"), the Clean Energy States Alliance ("CESA"), Vote Solar, the Natural Resources Council of Maine ("NRCM") and 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.

Can you please provide 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 2021 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. In addition, SEA also managed a stakeholder process in conjunction with OER and National Grid to explore and develop potential Public Policy Adders for proposal as potential pilot programs by National Grid to this Commission.

<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's first presentation was at a public meeting held by webinar on July 27, 2021, 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 8, 2021. The final ceiling price recommendations for all technology categories were presented at a DG Board public meeting held by webinar on October 25, 2021, where the prices were approved. SEA's three presentations are provided as **JK Schedule 1-3**, 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.[5] 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. Beginning in 2015, NREL re-released CREST models that allow the user to edit formulas, without limit.

Were the CREST models made available to stakeholders?

Yes. The CREST models are always available to the public. Any stakeholder may download a CREST model from NREL's website, without charge, and enter any number of different input configurations. In addition, on August 9, 2021, SEA released a custom version of the CREST model, as well as sample inputs included in an earlier draft of the analysis, via email to its list of Renewable Energy Growth Program stakeholders. Relative to the CREST model SEA designed for NREL, the customized version released to stakeholders includes several adjustments specific to Rhode Island (including, but not limited to, the way in which state and federal tax benefits are calculated). We enclose this public version of the model, as customized for our REG support for OER and the DG Board, as **JK Schedule 4**.

Were the Public Utilities Commission ("PUC") and Division of Public Utilities and Carriers ("DPUC") staff and consultants included on the communication to

[5] 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.

stakeholders that included the customized CREST model?

Yes.

Do you wish to make any changes to the model as provided to stakeholders at this time?

No, not to the core structure or calculations of the model. The inputs included in the model provided to stakeholders on August 9, 2021 via email can be substituted for the ones provided in the final October 25, 2021 consulting team presentation to the DG Board.

<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 **JK Schedule 5** below. SEA successfully followed up with stakeholders with two separate but simultaneous requests (one related to financing terms and another related to other cost and performance issues), which were closed following the second stakeholder meeting (described above). However, SEA made clear that stakeholders were free to offer formal and informal comments throughout the process. In addition, for the final recommended prices, SEA also undertook a survey of municipal assessors to determine their approach to taxing renewable energy projects, which did not yield information that caused the consulting team to change our approach.

Copies of all the survey instruments can be found in **JK Schedules 6-7**.

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 2020 process, however, 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. For summaries of comments provided by stakeholders and how SEA responded to them, please see **JK Schedules 1-3**, SEA's stakeholder presentations delivered as part of the ceiling price development process.

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 2022 recommended ceiling prices take other recent data sources (which are described and linked in **JK Schedules 1-3**) into account, particularly with respect to cost and financing trends, to incentivize the development of projects in Rhode Island that are price-competitive with similar projects throughout the region.

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. 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 2022 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 significant number of their suggested changes to the ceiling price inputs.

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

Yes.

Were 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 2021 program year with those proposed by OER and the DG Board for the 2022 program year?

OER and the DG Board's proposed renewable energy classes and corresponding eligible system sizes can be found in **JK Schedule 8**. **JK Schedule 9** compares the 2021 approved classes and eligible size ranges with the ones proposed for the 2022 program year.

Can you verify the 2022 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 **JK 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 2022 ceiling prices differ from the 2021 ceiling prices? If yes, please quantify the percentage change for each category.

Yes. The percentage change between the proposed 2022 ceiling prices and the final 2021 ceiling prices can be seen in **JK Schedule 11** below.

<u>Ceiling Price Development – Changes from 2021 Approved Solar Prices/Key Drivers of Change</u>

Please describe the most impactful drivers of changes in the proposed 2022 Program Year ceiling prices for the Solar categories relative to those approved for the 2021 Program Year.

Similar to the 2021 approved ceiling prices, the proposed 2022 ceiling prices reflect a mix of changes that place upward and downward pressure on costs and prices. I describe this mix of drivers of downward and upward pressure on the proposed ceiling prices below.

<u>Drivers of Upward Pressure on Proposed 2022 Solar Ceiling Prices</u>

- *Accounting for Year-on-Year Cost Pressures Expected to Affect Solar Projects in 2022 Open Enrollments:* As a result of a mix of substantial upstream supply chain challenges for Solar projects related to converging supply and demand shocks closely related to the effects of the COVID-19 pandemic, the proposed 2022 Solar ceiling prices incorporate an assumed year-on-year increase factor to reflect higher expected prices for projects expected to be bid during the 2022 program year. I detail our team's approach to the issue on pages 28-30.
- *Increases in Installed Capital Costs for Small Solar Projects:* Unlike Medium, Commercial and Large Solar projects, our analysis of Narragansett Electric bid data and publicly-available regional pricing data shows that even prior to accounting for any inflationary pressure likely to assert itself in 2022 (described above), the installed capital cost of Small Solar projects slightly increased.[6] **JK Schedule 12**

[6] As in prior years, our main sources for Solar project installed costs (the most significant driver of Solar project ceiling prices) for Solar projects remain 1) the installed cost estimates associated with bids submitted

shows the difference in installed capital costs between the 2021 approved prices and the initial values derived from the sources described above.

- *Reduced Capacity Factors for Small Solar I and II Projects:* The proposed ceiling prices for Small Solar projects include a reduction in assumed capacity factor from 14% to 13.4%. This change is intended to reflect a shift from utilizing values based on simulated data from the NREL PVWatts tool under idealized siting conditions to an average of that value with the median value from an analysis of real-world performance of Solar projects sized less than or equal to 25 kW_{DC}. I provide additional detail regarding this change in the question-and-answer series on pages 33-34.
- *Increased Annual Degradation Rates for Solar Projects <=1 MW:* Similarly, the proposed ceiling prices also reflect an increase in assumed annual degradation rates from 0.5%/yr for all Solar projects to 1.0%/yr for projects less than or equal to 25 kW_{DC}, and 0.8%/yr for projects greater than 25 kW_{DC} but less than or equal to 1 MW_{DC}, a change substantiated by a number of other independent and objective solar technology and performance analysts. More details on our approach to this question can be found in the Pre-Filed Direct Testimony of Tobin Armstrong.
- *Increases in Interest Rates on Term Debt for Solar >25:* While the 90-day London Inter-Bank Offering Rate (LIBOR) has declined slightly (and project financiers have reported charging premiums over LIBOR that are unchanged since 2020), our team's assumed effective "swap" rate for LIBOR[7] (which we peg to yields on U.S. Treasuries) has increased 70 basis points (0.7%), in line with increases in 10- and 20-year Treasury yields since 2020.[8] When netted against the decline in LIBOR since 2020, we estimate that the interest on term debt for solar projects greater than 25 kW_{DC} has increased by 60 basis points (0.6%).
- *Increased Land/Site Lease Costs for Certain Project Types:* The proposed prices also include increases in assumed land/site lease costs for Medium Solar II and Large Solar projects, which represent averages of the previous input and documented lease agreements newly shared with our team.
- *Increase in Observed Insurance Costs for Solar Projects >25 kW_{DC}:* Based on feedback from project developers, the proposed 2022 ceiling prices reflect a 27% increase in insurance costs as a percentage of the total cost of the project. It is also our understanding, based on information from insurance industry stakeholders, that the increases correspond to a larger number of payouts across the insurance industry generally (particularly related to natural disasters and other large loss events) over the past several years.
- *Small Solar I and II-Specific Financing Assumption Changes:* In response to feedback from Small Solar stakeholders suggesting that customers expected a more substantial return on REG projects, our team increased its assumed target after-tax equity internal rate of return (IRR) from 5% to 7%. In addition, our team also reduced the debt share for Small Solar I and II (in order to make adjustments to ensure proper debt service coverage) from 71% to 60% and 60% to 50%,

into the First Open Enrollment of the 2021 Program Year (obtained confidentially from Narragansett Electric, who obtains them from project developers), and 2) the publicly-available installed cost data from Rhode Island and other Northeastern states.

[7] The "swap rate" functionally amounts to the cost of locking in LIBOR over typical project loan tenors.

[8] The loan tenors assumed for the 2022 proposed Solar ceiling prices remain at 15 years for all Solar projects larger than.

respectively.

- *Reduction in Debt Share in Large Solar/Large Solar CRDG Capital Stack:* The proposed 2022 program year prices also include a slight reduction (from 55% to 52.5%) in the share of debt in the capital stack to ensure that the project would have sufficient debt service coverage.

<u>Drivers of Downward Pressure on Proposed 2022 Solar Ceiling Prices</u>

- *Region-Wide Installed Cost Reductions and 2021 1st Open Enrollment Results for Solar Projects Greater Than or Equal To 25 kW*: Prior to applying the year-on-year cost factor that increased most 2022 ceiling prices beyond their 2021 approved value, our team's analysis found that Medium, Commercial and Large Solar projects that had key materials and services procured ahead of the significant spike in actual and projected prices for key materials and inputs for Solar projects had somewhat lower capital costs than those assumed for the final 2021 approved prices.[9] **JK Schedule 12** below compares the final assumed installed costs for the 2021 approved and the installed costs inputs for the 2022 proposed ceiling prices prior to the application of the year-on-year factor for Medium, Commercial and Large Solar.[10]
- *Reduced Sponsor Equity IRR Values for All Solar Projects:* In light of the uncertainty associated with the COVID-19 pandemic (and particularly in light of the sharp drop in business activity during its initial months) the 2021 approved prices included higher assumed higher sponsor equity IRR requirements than those assumed for the 2020 program year. We assumed that such requirements would be higher (especially for host owners of Medium and Commercial Solar projects), given that sponsor equity IRRs are often a proxy for corporate hurdle rates for new investments, which are likely to rise during times of great uncertainty. In light of the fact that robust business activity is expected to persist into 2022 (despite ongoing producer price inflation and supply chain challenges), the proposed prices include a 50 basis points (0.5%) reduction in sponsor equity IRRs for Solar projects greater than 25 kW_{DC} to reflect the more robust expected business climate relative to 2021.
- *Reduction in O&M Costs for Small and Large Solar Projects:* Following a review of both high-quality objective analyses and the collection of feedback from REG stakeholders, the 2022 proposed prices include lower O&M costs for Small and Large Solar projects alike. Specifically, the assumed O&M costs (in $/$kW_{DC}$-yr) for Small Solar I and II dropped from $35 to $29 and $24, respectively, while the assumed O&M cost for Large Solar projects fell from $12 to $8.
- *Increases in Assumed Proxy Sizes of Small Solar I, Commercial Solar II and Large Solar Projects (including CRDG):* In part due to feedback from this Commission, the proposed 2022 ceiling prices also include increased proxy project sizes utilized for modeling, which our team chose to increase in light of the tendency of REG bidders to maximize the size of the project within the eligible size bin (in line with

---

[9] See Footnote 6

[10] The proposed 2022 installed cost values for Community Remote Commercial and Large Solar projects are $100/kW higher than for Commercial and Large Solar.

economies of scale in project development).[11] Specifically, the proxy system sizes increased from 5 kW_{DC} to 5.8 kW_{DC} for Small Solar I, 900 kW_{DC} to 1 MW_{DC} for Commercial Solar II projects (including CRDG) and from 4.5 MW_{DC} to 5 MW_{DC} for Large Solar projects (also including CRDG).

- *Increases in Post-Tariff Compensation Values:* In response to feedback from stakeholders that helped our team clarify its understanding of the Renewable Energy Growth Act's allowance that eligible projects are eligible for net metering following the cessation of their REG tariff term, our team has revised its assumptions for post-tariff compensation to reflect a value meant to approximate the compensation of a virtual net metering project, but subject to a 40% reduction to account for expected policy uncertainty.

Increase in Assumed Project Useful Lives: Based on a review of emerging industry practices (in which more market participants have indicated that they now assume Solar and Wind projects now have longer useful lives than previously assumed, our team also increased the expected useful life of solar projects to 25 years for all Solar projects less than or equal to 1 MW_{DC}, and to 30 years for all Large Solar and Large CRDG projects and all Wind projects. These values were adjusted upwards from 20 years, which our team increased as a result of changes to post-tariff compensation values described above.

For a full list of changes considered and undertaken for the proposed 2022 prices, please see **JK Schedules 1-3**.

Ceiling Price Development – Changes from 2021 Approved Wind, Hydro and Anaerobic Digestion Prices

Please describe the most impactful drivers of changes in the proposed Ceiling Prices for the Wind classes.

The primary driver for the change in the proposed price for Wind is the scheduled expiration of the federal Production Tax Credit ("PTC") on January 1, 2022. As a result, wind project developers nationwide will no longer be able to benefit from the Investment Tax Credit ("ITC") in lieu of the PTC. In addition, and in line with the other provisions intended to account for the significant rise in prices at every level of the Wind supply chain, the prices assume a 12% increase, in line with the Producer Price Index (PPI) driven approach (described in the question-and-answer series on pages 28-30). These increases were partially offset by a small increase in assumed tax equity – relative to sponsor equity – in the capital stack to account for the continued realization of depreciation benefits.

For a full list of changes for these resources, considered and undertaken for the proposed 2022 prices, please see **JK Schedules 1-3**.

Please describe the most impactful driver of changes in the proposed Ceiling Prices

[11] Increasing these proxy system sizes places downward pressure on the prices, since the increase in production reduces the ratio of the net present value of net project costs (plus a reasonable, market-reflective rate of return to its owners) to project production. Specifically

for the Anaerobic Digestion ("AD") and Small-Scale Hydropower ("Hydro") categories.

The main change in the assumptions utilized for Hydro and AD projects involved the reduction of the ITC in lieu of the PTC from 30% to 0%, as well as the increases in prices to account for the cost pressures currently present in the market (described in the question-and-answer series on pages 28-30).

For a full list of changes for these resources, considered and undertaken for the proposed 2022 prices, please see **JK Schedules 1-3**.

<u>Accounting for Cost Pressures Affecting all Renewable Energy Projects</u>

In general terms, please describe the methodology your team utilizes when developing inputs for upfront capital costs for use in the CREST model.

Each year, our team develops installed capital cost inputs based on a mix of publicly-available state databases, data from private vendors such as EnergySage, and Narragansett Electric bid data from the initial Open Enrollment of the prior year (where most of the program capacity is procured for any given year). In addition, our team also multiplies this installed capital cost term by one minus a year-on-year percentage (%) adjustment term (initially recommended to us by consultants to the DPUC in prior years), which is typically derived from NREL's Annual Technology Baseline. In each prior year that I have been part of the team developing recommended ceiling prices, this year-on-year term has typically been negative, given the sharp declines in both hard costs (for project materials and generation equipment) as well as soft costs.

Can you explain why, unlike previous years, there is such a substantial increase (rather than a decline) in the year-on-year change term?

Yes. While there is not one single driver that explains the rise in current and/or expected project costs, stakeholders that our team engaged with during the development process identified broadly-applicable cost pressures across both Solar and Non-Solar resource types as a result of the major dislocations caused by an uneven economic recovery (and simultaneous supply and demand shocks) related to the COVID-19 pandemic. Specifically, our research and engagement with stakeholders both related and unrelated to the REG program development process yielded the following findings regarding costs for generation equipment for projects currently under development (and thus likely to target the 2022 Open Enrollments) for potential qualification or bid selection in 2022.

- Solar stakeholders indicated that they were being quoted prices by EPCs and/or other equipment vendors that reflected 5%-15% across-the-board increases in capital costs;
- One hydro stakeholder indicated that his company's capital costs had risen because of the doubling (and in some cases, tripling) in the price of steel since 2020; and

- Independent wind market analysts have suggested certain key 2022 project costs are likely to increase 10% relative to those proposed during the current year.[12]

These entities tended to most frequently cite the high costs and delays related to shipping, as well as sharp increases in commodity inputs, such as polysilicon (for solar cells and modules) and steel (a material critical to all renewable energy projects).

What were some of the key principles your team utilized in developing an approach for accounting for these (historically) atypical increases in costs?

As I have mentioned previously in this testimony (and in testimony filed in support of prior year proposed prices before this Commission), our overarching goal is to develop compensation approaches for eligible projects that balance the goals of healthy market development with the minimization and/or mitigation of the cost of the program for ratepayers. Furthermore, it has always been our goal to be fully transparent about the inputs we utilize, and that such inputs can be scaled to match with changing market conditions.

Given these key principles, please describe the methodology your team utilized to account for these anticipated 2022 market drivers when calculating the year-on-year change term for the Solar ceiling prices.

To derive the year-on-year change term, we utilized the forecasted Producer Price Index (PPI) change from 2020 to 2022 contained in the most recent U.S. Energy Information Administration (EIA) Short-Tern Energy Outlook. (+12% in the most recent EIA Short-Term Energy Outlook (STEO)) as an adder to non-interconnection installed costs. We then offset this increase by the expected year-on-year rate of fundamentals-based forecasted cost reduction from the "Moderate" case utilized in the 2021 NREL ATB.[13] **JK Schedule 13** is a table that shows the combined year-on-year change factors for various Solar project types.

Please describe the methodology your team utilized for calculating the year-on-year change term for the (Non-Solar) Wind, Small-Scale Hydroelectric and Anaerobic Digestion ceiling prices.

For Wind and Anaerobic Digestion (AD) projects, our team assumed the same EIA STEO estimate as for Solar projects, but without a corresponding decline intended to represent the cost fundamentals of solar PV over time, given that our team has not detected any major long-term cost declines for larger-scale distributed wind projects or AD projects. For Hydro projects, our team utilized data from a hydro market participant indicating a 30% increase in construction costs (driven by the commodity cost of steel in many of the moving parts of a hydroelectric project) and averaged with the EIA STEO estimate described above.

---

[12] Wood Mackenzie. *Wind turbine prices to rise by up to 10%*. 16 August 2021. Available at: https://www.woodmac.com/press-releases/wind-turbine-prices-to-rise-by-up-to-10/

[13] Data and spreadsheets utilized for calculating these values can be found at: https://data.openei.org/submissions/4129

Despite the substantial increases in prices due to the use of these year-on-year capital cost increase factors, do you still believe that use of these factors is consistent with the goals of the program, and that your team has taken appropriate steps to counterbalance these increases with steps that mitigate ratepayer cost?

Yes, I do. The objective of the REG ceiling price development process is the development of prices that serve as a good approximation of total development costs typical to the Northeast region plus a reasonable, market-based rate of return. Given that these costs have, at least on a temporary basis, markedly increased as a result of unprecedented disruptions in the global economy that affect many of the raw materials and finished goods necessary to construct renewable energy projects, we believe that proposing prices that account for these changes is consistent with the law and necessary to ensure that projects currently under development have the certainty to proceed with bidding in the 2022 program year. Furthermore, as described in other portions of my testimony, our team has also incorporated a wide variety of other input assumptions, some of which counterbalance these price increases.

Furthermore, and even if other shifts cause these forecasted price changes to be mitigated relative to expectations, we believe that the ceiling price-based structure of the procurements will allow ratepayers to benefit from bidders that are able to obtain components and/or labor services that are less costly to be more likely to be selected. Such an outcome would not only inform potential future ceiling price reductions but would also benefit ratepayers relative to the prices as proposed.

At this time, do you expect that the conditions that produced such large year-on-year increases will persist into 2023, and thus result in prices that are the same or higher than proposed for the 2022 program year?

At this time, it is unclear whether some of the inflationary factors derived from the EIA STEO forecasts (and accounted for in the prices) will abate either during 2022 or 2023. However, we have moderate confidence that these factors represent relatively temporary (rather than long-term and durable) cost and price shifts related to the COVID-19 pandemic, and thus are reasonably likely to dissipate in conjunction with fewer supply chain disruptions.

<u>Further Subdivision of Solar Renewable Energy Classes and Adjustments to Proxy Sizes</u>

Pursuant in part to feedback from this Commission, did your team embark on an investigation of further subdivisions of the Solar renewable energy classes?

Yes, we did. At the recommendation of Chair Gerwatowski and the PUC, our scope of work this year included a broader reconsideration of how the Solar renewable energy classes could be subdivided, in order to build upon the subdivisions approved for the 2021 program year.

What key principles did your team utilize in considering further subdivisions of the Solar renewable energy classes?

When developing proposed subdivision options for stakeholders, our team utilized three key principles, which were derived from the statutory purpose of the Renewable Energy Growth (REG) program (R.I. Gen. Laws § 39-26.6-1). I describe these in the bullets below.

- *Optimization of Statewide Solar Potential:* Our team defines Rhode Island's solar potential as a product of the available (read: non-restricted) parcels of land and roof space, as constrained by the state's transmission and distribution hosting capacity. Based on our knowledge and research of Rhode Island and other Northeast solar markets, the current pattern of development favoring projects larger than 500 kW_{DC} tends to trigger expensive, time-consuming transmission and distribution (T&D) impact studies that, over time, will likely pose increasing risks to REG and net metering projects >1 MW under development. Thus, when developing subdivision options, a key consideration for our team was balancing the deployment of projects greater than 500 kW_{DC} with the development of diverse array of projects sited closer to load.
- *Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost:* Our team also recognizes that another core principle undergirding the REG program is economic efficiency, particularly in the design of size bins that reflect appropriate break points for upfront capital and non-capital (operating) costs that maximize ratepayer benefits (and limit net costs to ratepayers). Thus, another key consideration in developing subdivision options was the maximization of returns to scale, with the proviso that such options do not crowd out development of projects that can optimize statewide potential (as described in the first principle).
- *Mitigation of Siting Impacts*: Our team (and OER) have also observed that the increasing degree of large-scale and DG solar development in western Rhode Island – an area that also has constrained hosting capacity - has led to increased local conflict over DG project siting. These patterns of development are driven in part by strong incentives to develop larger-scale greenfield projects in the REG program, a product of the desire to limit the direct cost of the program to ratepayers. Nevertheless, the REG statute section referenced above includes "reduc(ing) environmental impacts" as one of its goals. Thus, our team believed it prudent (and consistent with statute) to consider this principle when considering further Solar class subdivisions.

Did your team develop and consider multiple options for subdividing the Solar renewable energy classes?

Yes. The options that were considered, as well as how the options appeared to fit with the three key principles described above, can be found on pages 45-62 of **JK Schedule 1.**

Were these size bin and proxy system size options, as developed and presented to stakeholders, based on input they previously provided to your team?

Yes, they were. In fact, feedback we received in the Data Request and Survey (see **JK Schedule 6**) included a series of specific size bin break points intended to illustrate the points at which economies of scale were maximized. Please see **JK Schedule 14** for a table illustrating these potential break points.

Please describe the process by which your team conducted outreach to affected Solar stakeholders, as well as the results of that outreach.

On July 27, 2021, our team held a virtual meeting with stakeholders, hosted by OER staff, at which members of our team, among other activities, reviewed these subdivision options. Following that meeting, our team also requested and received stakeholder comment. The comments received in response to this feedback are summarized in page 3 of **JK Schedule 2**.

Please describe the changes to the Solar renewable energy classes and proxy system sizes that were utilized in developing the proposed ceiling prices.

The feedback from stakeholders (including the DPUC) suggested the greatest degree of overlap in preference regarding Option C, which results in the following Solar renewable energy classes for projects greater than 25 kW_{DC}:

- *Medium Solar I*, with a size bin that includes projects greater than 25 kW_{DC} and less than or equal to 150 kW_{DC}, modeled with a proxy size of 150 kW_{DC};
- *Medium Solar II*, with a size bin that includes projects greater than 150 kW_{DC} and less than or equal to 250 kW_{DC}, modeled with a proxy size of 250 kW_{DC}**;**
- *Commercial Solar I & Commercial Solar I CRDG*, with a size bin that includes projects greater than 250 kW_{DC} and less than or equal to 500 kW_{DC}, modeled with a proxy size of 500 kW_{DC};
- *Commercial Solar II & Commercial Solar II CRDG*, with a size bin that includes projects greater than 500 kW_{DC} and less than or equal to 1 MW_{DC}, modeled with a proxy size of 1 MW_{DC}; and
- *Large Solar & Large Solar CRDG*, with a size bin that includes projects greater than 1 MW_{DC} and less than or equal to 5 MW_{DC}, modeled with a proxy size of 5 MW_{DC}

The approach, including the upfront capital cost estimate for the newly-split Medium Solar I and II categories and the revised Commercial Solar II category is described further on page 3 of **JK Schedule 2**.

Do you believe these changes more appropriately balance healthy market development with ratepayer cost mitigation and the minimization of environmental impact than the previous Solar subdivisions?

Yes, I do. I believe that the "Option C" approach effectively balances all three of the key principles. Specifically, it is our view that:

- Limiting the maximum size of the smallest Commercial Solar category to 500 kW_{DC} will, all other factors equal, ensure that projects larger than 500 kW_{DC} and no larger than 750 kW_{DC} will be compensated at a more cost-effective level for ratepayers;

- Increasing the proxy sizes for modeling to the top end of the capacity bin in question will ensure all renewable energy classes reflect the most cost-effective ceiling prices for ratepayers; and
- Creating a Medium Solar I class and limiting the maximum size of the Commercial Solar I class will, all other factors equal, likely encourage a healthier degree of project development takes place both on customer rooftops (given that most projects at these system scales are located on rooftops) and closer to load (a step likely to incrementally limit interconnection costs for eligible projects);
- Encouraging development on rooftops is likely, all factors equal, to mitigate siting impacts to at least some degree (by limiting development of ground-mounted projects within the Medium and Commercial categories).

Does this proposed approach <u>guarantee</u> all these potential benefits will take place?

No, it does not. However, based on the feedback we received, we do believe that it represents an approach that all stakeholders can support, and is more likely than not to result in positive impacts related to all three above-described principles.

<u>Adjustments to Assumed Small Solar Capacity Factors and Solar Production Degradation Rate</u>

What factors led your team to consider changes to the Small Solar capacity factors?

Historically the Small Solar I and II capacity factors have remained constant at 14% to reflect the simulated capacity factor for a proxy project in Rhode Island in NREL PVWatts. However, during the final months of 2020, it is our understanding that Small Solar market participants reached out directly to OER and to Narragansett Electric to request that the company revise the formula (which assumes the same 14% DC capacity factor) it uses to calculate solar PV system sizing to load to incorporate what the industry suggested were lower in-practice capacity factors. In our firm's experience, these lower in-practice capacity factors tend to result from non-optimal tilt and azimuth angles associated with projects sited on rooftops (and which are often partially shaded). Narragansett then decided to undertake an analysis of the capacity factors of projects incentivized by the company. A copy of a presentation describing the results of that study is attached as **JK Schedule 15**.

The Narragansett Electric analysis described in the aforementioned schedule specifically found that the median project in Rhode Island underperformed the 14% value by 8.7% (on a relative basis), resulting in a median in-practice capacity factor of 12.8%. Following this analysis, the company changed its sizing guidelines to a table of values based on varying tilts and azimuths (but centered on the aforementioned 12.8% median value).

Did your team develop a set of potential options regarding the appropriate Small Solar capacity factor input and share them with affected stakeholders?

Yes. **JK Schedule 16** shows the three specific options proposed to REG stakeholders in a presentation dated July 27, 2021. Following this presentation to stakeholders, our team requested stakeholder comment through August 20, 2021. Only the DPUC responded to the comment request. Their comments indicated that they were "fully supportive" of using actual historical production data to inform this key input, but wished to have additional information regarding Narragansett's analysis prior to commenting further. It is unclear to us at this time whether that information was provided. I enclose their comments to us from August 20, 2021 on this matter (and other matters) as **JK Schedule 17**.

Please describe the methodology your team ultimately settled on to develop the Small Solar input utilized in the recommended prices.

Our team concurs with the DPUC's view that using actual historical production data to inform the capacity factor input is desirable and recommend a ceiling price with a capacity factor that averages the current 14% capacity factor for Small Solar projects with the 12.8% capacity factor. Our team believes this method represents the approach that likely best balances the objective of ratepayer cost mitigation with findings that Small Solar projects are projects are unlikely to be sited to produce an amount of energy that corresponds with more ideal tilts and azimuths. As such, this approach is utilized in the proposed 2022 ceiling prices for Small Solar projects.

<u>Community Remote Distributed Generation (CRDG)</u>

In the testimony you filed in Docket 5088, did you indicate that the SEA team would be willing to revisit its incremental CRDG capital and operating cost estimates?

Yes, I did.

Please detail the changes made to incremental capital and operating cost input assumptions incorporated into the ceiling prices for Community Remote Distributed Generation (CRDG) projects.

Following engagement with developers active in community shared solar markets in the Northeast, SEA was able to discern that the incremental upfront capital cost associated with CRDG projects not serving low- and moderate-income (typically associated with upfront costs of customer acquisition prior to commercial operation) has fallen from $150/kW_{DC}$ to $100/kW_{DC}$. Our team was also able to learn that the incremental operations and maintenance (O&M) costs for CRDG projects has fallen from $25/kW_{DC}$-yr to $22/kW_{DC}$-yr.

Does this reduction in the cost change the ceiling prices for Solar CRDG projects? Why or why not?

No, it does not. The change in the input does not ultimately flow through to customers as a direct result of the 15% cap on CRDG incremental costs imposed by R.I. Gen. Laws § 39-26.6-27. As shown in **JK Schedule 18** the change in the assumed capital and operating cost terms only reduced the uncapped CRDG premium for Commercial Solar I, Commercial Solar II and Large Solar. However, since the ceiling prices must (per R.I. Gen. Laws § 39-26.6-27) be limited to a premium equivalent to 15% of a similarly situated non-CRDG project, the reduced input value did not affect the proposed prices for CRDG projects.

Does this reduction in the assumed incremental cost inputs for CRDG projects change

the ceiling prices for Wind CRDG projects? Why or why not?

Yes, it does. With the new assumptions, the premium cost of Wind CRDG projects (relative to Wind projects) is slightly under 10%. This premium cost reduction is reflected in the prices because the incremental CRDG capital and operating costs represent less than a 15% premium relative to the underlying Wind capital and operating costs.

Do you believe that the proposed ceiling prices continue to be in line with typical pricing for CRDG projects?

Yes. While Commercial Solar CRDG projects are somewhat less common overall (and thus there are not as many potential projects to compare pricing to), it is our understanding (based on confidential discussions with market participants) that typical 20-year levelized revenue requirements for projects between 1 and 5 MW_{DC} can vary between 12-14 ₵/kWh over the term of a 20-year bundled tariff. As such, we believe the proposed prices are a reasonable ceiling price under which well-capitalized and creditworthy developers can compete to offer the best price without providing below-market rate returns to debt and equity investors.

<u>Interconnection Costs</u>

How do the proposed 2021 ceiling prices account for the cost of distribution system interconnection?

Each year, SEA requests National Grid's database of Massachusetts and Rhode Island interconnection costs on a project-by-project basis. While these values are not specifically added to the build costs collected by SEA in other Northeastern states (since interconnection costs are presumed, based on experience, to be included), we utilize these interconnection cost data to remove interconnection costs from the basis for the ITC, and from utilizing 5-year MACRS depreciation, a form of accelerated depreciation. Therefore, if interconnection costs rise (and all other factors remain equal), the amount of project costs removed from the basis for calculating these federal tax benefits will rise, thereby increasing the ceiling price. If interconnection costs were to drop, ceiling prices would drop for the same reasons outlined above.

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

As in previous years, SEA calculated the average cost of interconnection across Massachusetts and Rhode Island in the dataset provided by National Grid, which included data through the middle of 2021. 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 2020, as well as the available 2021 data. **JK Schedule 19** below shows these interconnection costs for the Solar and Wind classes.

Does the interconnection approach differ for the Hydro and Anaerobic Digestion classes?

The approach to accounting for interconnection costs is the same for the Hydro and Anaerobic Digestion classes in that interconnection costs are separated from other capital costs and not included in the basis for federal tax benefits. However, given the scarcity of hydro and anaerobic digestion projects, the value of the interconnection cost assumption has not changed from prior stakeholder guidance. The impact of the magnitude of interconnection costs is smaller for Hydro and Anaerobic Digestion, as these projects, under current law, do not qualify for federal tax credits, and thus the impact is limited to the difference in depreciation schedules.

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

Yes. As the Commission is aware, Narragansett Electric'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 most 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 both the 2021 and 2022 ceiling price development process, stakeholders have raised a number of issues with us regarding the costs and delays associated with both transmission and distribution level impact studies (as well as distribution interconnection individual and group studies), including:

- 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
- The potential that projects facing unusually long interconnection delays may, as a result of not reaching commercial operation, lose eligibility for the higher federal Investment Tax Credit (ITC) at a "safe harbored" value of between 22% and 30% (and would be required to accept 10%, as under current tax law).

What were the findings of SEA's analysis?

It is our team's view, as validated by our firm's intensive surveillance of Northeast renewable energy markets and policy development processes, the above-described market conditions are likely, at some point in time in the future, to subject a large number of currently-proposed REG and net energy metering projects (including those already constructed) to the aforementioned delays, costs and uncertainties are at moderate to high risk of cancellation.

Nevertheless, our team has concluded that we are not well-positioned to propose solutions for projects in extended transmission and/or distribution studies that would impact the 2022 program year, given a series of fundamental, institutional, and practical challenges that inhibit OER, the DG Board, and our team from proposing credible and statutorily permissible solutions. 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, or the authority, through the ceiling prices, to propose to this Commission how developers should be compensated for them. These challenges are detailed on pp. 4-6 of **JK Schedule 20.**

However, we did identify one area in which we believe that certain potential costs and risks associated with these transmission (and even, conceivably, distribution) impact studies with extended study timelines and post-study construction periods the proposed ceiling prices could be mitigated, especially if current federal laws governing renewable energy tax credits remain unchanged. Specifically, our team has proposed for consideration during the 2023 program year that projects greater than or equal to $\geq$1 MW, for which their statutory/IRS-determined "safe harbor" placed-in-service deadline has lapsed (resulting from ASO-related circumstances <u>beyond their control</u>), would have their REG tariff compensation rate adjusted to account for tax credit eligibility loss. However, to preserve the initial benefits of competition flowing to ratepayers from the initial Open Enrollment in which the project was selected, the "true-up" amount would be scaled down proportional to difference between Ceiling Price and as-bid PBI value. This proposal, including a potential formula is detailed on pp. 10-13 of **JK Schedule 20**.

Our team is aware, however, that this proposal would not be as useful or as relevant during the 2023 program year if long-term extensions of the federal renewable energy tax credits are enacted in either 2021 or 2022. As such, our team (and OER and the Board) would be unlikely to propose the implementation of proposal unless and until another tax credit "placed-in-service" cliff presented itself that is likely to be relevant for affected projects.

Did SEA engage with stakeholders on the results of its analysis?

Yes, we did. On September 29, 2021, our team held a stakeholder meeting to discuss this proposal, at which no stakeholder objected to the proposal. Prior to the meeting, our team also liaised with DPUC and Narragansett Electric staff, who indicated openness to considering the proposal during the 2023 program year if federal tax credits are not materially extended beyond current law. Finally, our team also solicited comment on the proposal through October 8, 2021, but no comments were received.

What next steps does SEA plan to take in the 2023 program year process and beyond?

In terms of the proposal described above, it is unclear at this time what steps SEA can or will propose to take at this time during the 2023 program year. Regardless, our team will continue to monitor the development of federal legislation to extend the applicable federal tax credits, as well as the progression of transmission and distribution impact studies in the state to determine if changes to interconnection cost inputs are warranted.

<u>Tax Treatment of REG Performance-Based Incentive Payments for Solar Projects</u>

Did SEA receive comments from the DPUC regarding the taxation of income for Small Solar projects?

Yes. The DPUC argued in a set of written comments (attached as **JK Schedule 21**) that because Narragansett Electric customers can have PBI payments conveyed to them in the form of a bill credit, that (per Internal Revenue Service (IRS) guidelines) bill credits are not considered to be taxable income. As a result, the DPUC argued that the ceiling prices for Small Solar projects should not assume that the owner pays federal taxes.[14]

Did SEA make a change to those assumptions to address DPUC's request? Why or why not?

No, we did not. The Narragansett Electric Tax Policy Statement[15] reads, in pertinent part:

Payments for Performance Based Incentives and associated bill credits in the RE Growth program ***will be taxable income for some recipients (emphasis added)****. As the payer, National Grid is obligated to report this income on Form 1099. To enable the Company to meet its obligation, all applicants/owners and associated customers receiving bill credits for enrolled facilities must provide National Grid with completed Form W-9s subject to the following conditions.*

In terms of ceiling price development, the most important part of this statement is that <u>at least some</u> bill credit payments (as PBI payments) "will" incur a tax liability that must be paid (directly or indirectly) by participating system owners. As such, to avoid a scenario in which a large (and, importantly, currently unknown) proportion of participants are undercompensated for their costs plus a reasonable rate of return, SEA has determined that it is prudent to assume that the typical participant is liable for up to all the potential taxes on their PBI income.

However, our team is open to reconsidering this assumption during the 2023 program year if Narragansett Electric can provide our team with a clear historical accounting of the taxes paid by the Company on behalf of participating project owners by calendar year, as well as the amount of PBI payments paid by calendar year, since the beginning of the program. With this information in hand, we believe that we could more prudently assess whether it might be reasonable to assume an amount less than 100% of all PBI payments are taxable. At present, however, we do not recommend making such a change without such information in hand.

<u>Reasonableness of 2022 Recommended Ceiling Prices</u>

Does SEA believe that the importance of both policy objectives and cost-effectiveness

---

[14] In their comments, the DPUC did not specifically argue for or against assuming any state income taxes in the proxy ceiling price calculations, and thus those values remain as inputs to the ceiling prices.
[15] Available at: https://www9.nationalgridus.com/narragansett/non_html/RE_Growth_Tax_Policy_2017.pdf

were considered in its analysis and recommendations?

Yes. SEA believes 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 October 25, 2021 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 2022 REG program was consistent with all prior years in which the PUC has approved the Ceiling Prices?

Yes.

Does this conclude your testimony?

Yes.

JK Schedule 1 – SEA First Stakeholder Meeting Presentation

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

JK Schedule 2 – SEA Second Stakeholder Meeting Presentation

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

JK Schedule 3 – SEA Third Stakeholder Meeting Presentation

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

JK Schedule 4 – RI REG-Specific CREST Models Shared with Stakeholders

See file named: JK Schedule 4 – RI REG-Specific CREST Models Shared with Stakeholders.xlsm

JK 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		
	1st Round[16]	2nd Round[17]	3rd Round[18]
Solar	14	5	0
Non-Solar	1	1	0
Solar/Non-Solar	2	2	1

[16] Data requested from stakeholders on June 2, 2021.
[17] Ahead of July 27, 2021 Presentation.
[18] Ahead of September 8, 2021 Presentation.

JK Schedule 6 - Initial Data Request and Survey for 2022 Ceiling Price Process

See file named: JK Schedule 6 - Initial Data Request and Survey for 2022 Ceiling Price Process.pdf

JK Schedule 7 – Supplemental Data Request to Municipalities

See file named: JK Schedule 7 – Supplemental Data Request to Municipalities.pdf

JK Schedule 8 – 2022 Proposed Renewable Energy Classes and Eligible System Sizes

2022 Proposed Renewable Energy Classes and Eligible System Sizes	
Renewable Energy Class	**Eligible System Sizes**
Small Solar I	1-15 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	$\leq$ 5 MW_{AC}
Anaerobic Digestion	$\leq$ 5 MW_{AC}
Small Scale Hydropower	$\leq$ 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	$\leq$ 5 MW_{AC}

JK Schedule 9 – Comparison of 2021 Approved and 2022 Proposed Renewable Energy Classes and Eligible System Sizes

Comparison of 2021 Approved and 2022 Proposed Renewable Energy Classes and Eligible System Sizes			
2021 Final Approved		**2022 DG Board Recommended**	
Renewable Energy Class	**Eligible System Sizes**	**Renewable Energy Class**	**Eligible System Sizes**
Small Solar I	1-15 kW_{DC}	Small Solar I	1-15 kW_{DC}
Small Solar II	15-25 kW_{DC}	Small Solar II	>15-25 kW_{DC}
Medium Solar	26-250 kW_{DC}	Medium Solar I	>25-150 kW_{DC}
		Medium Solar II	>150-250 kW_{DC}
Commercial Solar I	251-750 kW_{DC}	Commercial Solar I	>250-500 kW_{DC}
Commercial Solar II	751-999 kW_{DC}	Commercial Solar II	>500-1000 kW_{DC}
Large Solar	1-5 MW_{DC}	Large Solar	>1-5 MW_{DC}
Wind	$\leq$ 5 MW_{AC}	Wind	$\leq$ 5 MW_{AC}
Anaerobic Digestion	$\leq$ 5 MW_{AC}	Anaerobic Digestion	$\leq$ 5 MW_{AC}
Small Scale Hydro	$\leq$ 5 MW_{AC}	Small Scale Hydro	$\leq$ 5 MW_{AC}
Community Remote – Commercial Solar	251-750 kW_{DC}	Community Remote – Commercial Solar	>250-500 kW_{DC}
	751-999 kW_{DC}		>500-1000 kW_{DC}
Community Remote – Large Solar	1-5 MW_{DC}	Community Remote – Large Solar	>1-5 MW_{DC}
Community Remote – Wind	$\leq$ 5 MW_{AC}	Community Remote – Wind	$\leq$ 5 MW_{AC}

JK Schedule 10 – 2022 Proposed Ceiling Prices, Eligible System Sizes and Tariff Terms

2022 Proposed Ceiling Prices, Eligible System Sizes and Tariff Terms			
Renewable Energy Class	**Tariff Term (Years)**	**Eligible System Size**	**Ceiling Price (¢/kWh)**
Small Solar I	15	1-15 kW_{DC}	31.05
Small Solar II	20	>15-25 kW_{DC}	27.55
Medium Solar I	20	>25-150 kW_{DC}	26.65
Medium Solar II	20	>150-250 kW_{DC}	24.45
Commercial Solar I	20	>250-500 kW_{DC}	19.25
Commercial Solar II	20	>500-1000 kW_{DC}	15.75
Community Remote – Commercial Solar	20	>250-500 kW_{DC}	22.14
		>500-1000 kW_{DC}	18.11
Large Solar	20	>1-5 MW_{DC}	10.95
Community Remote – Large Solar	20	>1-5 MW_{DC}	12.59
Wind	20	≤ 5 MW_{AC}	22.4
Community Remote – Wind	20	≤ 5 MW_{AC}	24.6
Anaerobic Digestion	20	≤ 5 MW_{AC}	25.55
Small Scale Hydropower	20	≤ 5 MW_{AC}	37.15

JK Schedule 11 – Percentage Change from 2021 Approved to 2022 Proposed REG Ceiling Prices

Percentage Change from 2021 Approved to 2022 Proposed REG Ceiling Prices		
Category	**Eligible System Size**	**% Change (2021-2022)**
Small Solar I	1-15 kW_{DC}	8%
Small Solar II	>15-25 kW_{DC}	13%
Medium Solar I	>25-150 kW_{DC}	N/A
Medium Solar II	>150-250 kW_{DC}	N/A
Commercial Solar I	>250-500 kW_{DC}	4%
Commercial Solar II	>500-1000 kW_{DC}	3%
Community Remote – Commercial Solar	>250-500 kW_{DC}	4%
	>501-1000 kW_{DC}	3%
Large Solar	>1-5 MW_{DC}	-4%
Community Remote – Large Solar	>1-5 MW_{DC}	-4%
Wind	$\leq$ 5 MW_{AC}	19%
Community Remote –Wind	$\leq$ 5 MW_{AC}	17%
Anaerobic Digestion	$\leq$ 5 MW_{AC}	61%
Small Scale Hydropower	$\leq$ 5 MW_{AC}	36%

JK Schedule 12 – Percentage Change in Upfront Capital Costs for Selected Proxy Solar Projects from 2021 Approved to 2022 Proposed REG Ceiling Prices

Percentage Change in Upfront Capital Costs for Selected Proxy Solar Projects from 2021 Approved to 2022 Proposed REG Ceiling Prices				
Category	**Eligible System Size(s)**	**2021 Approved**	**2022 Proposed**	**% Change**
Small Solar I	1-15 kW_{DC}	\$3,146	\$3,377	7%
Small Solar II	>15-25 kW_{DC}	\$2,883	\$3,103	8%
Medium Solar I	>25-150 kW_{DC}	\$2,332	\$2,792	N/A
Medium Solar II	>150-250 kW_{DC}		\$2,408	N/A
Large Solar	>1-5 MW_{DC}	\$1,492	\$1,444	-3%

JK Schedule 13 – Adjustments to Installed Cost Inputs

Category	Year-on-Year (YoY) Project Cost Factor *Before* Impact of Producer Price Index (NREL ATB 2021)[19]	YoY Project Cost Factor *After* Impact of Producer Price Index (2nd Draft)	YoY Project Cost Factor *After* Impact of Producer Price Index (Final Recommended)[20]
Small Solar I / II	-4.3% to -9.9%	0% to 6%	***2%***
Medium Solar, Commercial Solar, Comm. Solar CRDG	-4.3% to -8.0%	2% to 6%	***4%***
Large Solar, Large Solar CRDG	-4.0% to -7.4%	3% to 6%	***5%***

[19] Range represents "Conservative" and "Moderate" cases from 2021 NREL Annual Technology Baseline (ATB)
[20] Represents "Moderate" 2021 NREL ATB Case

JK Schedule 14 – Potential Breakpoints for Solar Class Subdivision (Based On Stakeholder Feedback)

	Bounding	Range of 1st kW Threshold	Range of 2nd kW Threshold	Range of 3rd kW Threshold	Range of 4th kW Threshold	Range of 5th kW Threshold
Upfront Capital Costs & Non-Capital Operating Costs	Low End Survey Response(s) (by Capacity)	100-150 kW	500 kW	1 MW	2 MW	4 MW
	High End Survey Response(s) (by Capacity)	250 kW	1 MW	2 MW	3 MW	5 MW

JK Schedule 15 – National Grid Solar Capacity Factor Research and Recommendation

See file named: JK Schedule 15 – National Grid Solar Capacity Factor Research and Recommendation.pdf

JK Schedule 16 – Small Solar Capacity Factor Options

Year 1 Capacity Factor (%)	
Approach Summary	Assumed Value
Capacity factor from 2021 CPs left unchanged	14.0%
Unweighted average of SEA and NGRID-derived capacity factors	13.4%
Assumptions of NGRID-derived capacity factor from RI-based analysis (described in other slides)	12.8%

JK Schedule 17 – August 20, 2021 Comments from Division of Public Utilities and Carriers

See file named: JK Schedule 17 - August 20 DPUC Comments.pdf

JK Schedule 18 – Comparison of Non- Community Remote DG Prices to CRDG Prices With and Without 15% Statutory Premium Caps by Category

Comparison of Non- Community Remote DG Prices to CRDG Prices With and Without 15% Statutory Premium Caps by Category				
Renewable Energy Class	**Size**	**Non-CRDG Price (₵/kWh)**	**CRDG Price (15% CRDG Cap, ₵/kWh)**	**CRDG Price (Uncapped, ₵/kWh)**
Commercial Solar I	>250-500 kW_{DC}	19.25	22.14	22.35
Commercial Solar II	>500-1 MW_{DC}	15.75	18.11	18.85
Large Solar	>1-5 MW_{DC}	10.95	12.59	14.05
Wind	0-5 MW_{AC}	22.40	24.60[21]	24.60[22]

[21] This value is the actual proposed Wind CRDG price, rather than the 15% limit. A Wind CRDG price that reaches the 15% limit would be 25.76 ₵/kWh.
[22] Ibid.

JK Schedule 19 – Comparison of 2021 Approved and 2022 Proposed National Grid- Supplied Distribution Interconnection Costs for Projects Larger than 25 kW_{DC}

Comparison of 2021 Approved and 2022 Proposed National Grid- Supplied Distribution Interconnection Costs for Projects Larger than 25 kW_{DC}			
Renewable Energy Class	**Eligible System Size**	**IC $/kW_{DC}$ (2021 Approved Prices)**	**IC $/kW_{DC}$ (2022 Recommended Prices)**
Medium Solar[23]	25-250 kW_{DC}	$118	$187
Commercial Solar	251-1000 kW_{DC}	$133	$114
Large Solar	1-5 MW_{DC}	$147	$173
Wind	0-5 MW_{AC}	$295	$295

[23] 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.

JK Schedule 20 – SEA Presentation to Stakeholders on Interconnection Issues

See file named: JK Schedule 20 – SEA Presentation to Stakeholders on Interconnection Issues.pdf

JK Schedule 21 - Comments from the DPUC regarding Small Solar Taxation

See file named: JK Schedule 20 - Comments from the DPUC regarding Small Solar Taxation.pdf

<u>Pre-Filed Direct Testimony of Jason Gifford – Sustainable Energy Advantage, LLC</u>

Please state your name, employer, and title.

My name is Jason Gifford. I am employed by Sustainable Energy Advantage, LLC ("SEA") as Senior Director.

Please provide your background related to renewable energy policy, technology, and analysis.

I have over 23 years of experience in the development of renewable energy policy, strategy, and market analysis. At SEA, I've spent the past 15 years supporting both public sector policy development and private sector understanding of, and investment in, renewable energy markets. I manage a broad range of quantitative and qualitative analyses of renewable energy policy and market dynamics, co-lead SEA's Renewable Energy Market Outlook (REMO) – a REC supply, demand, and price forecasting service, and lead SEA's financial modeling and advisory practice. I have a Bachelor of Arts from Bates College and a Master of Business Administration from the F.W. Olin Graduate School of Business at Babson College.

Please provide SEA's background related to renewable energy policy and markets.

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

What is SEA's role in support of the Renewable Energy Growth 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 provide detailed research and analysis to support the DG Board and OER's informed decision-making related to ceiling prices. Please see the testimony of Jim Kennerly for a detailed discussion of the ceiling price analysis.

More recently, SEA has also been directed to conduct research, stakeholder interviews, and a benefit-cost analysis (BCA) to support the PUC's consideration of a carport pilot program.

Please describe your role, past and present, related to SEA's support of the Renewable Energy Growth Program.

I have contributed to SEA's support of the REG Program since 2011. I have had the opportunity to draft market participant surveys and conduct stakeholder interviews. I have managed the collection of regional and national renewable energy project data and conducted detailed quantitative analyses in fulfillment of REG Program criteria related to ceiling prices. I was the primary architect of the Cost of Renewable Energy Spreadsheet Tool (CREST) model, under contract to NREL. I have had the opportunity to present and facilitate robust discussions at numerous stakeholder engagement meetings, and to testify before the PUC. More recently, I've served as a senior advisor to SEA's analytical team. In 2021, I managed SEA's update of the carport benefit cost analysis.

Context and Objectives for Carport Adder Benefit-Cost Analysis

What has been SEA's scope of work with respect to the Carport Solar pilot program?

In February 2020, the PUC approved a pilot Carport Solar adder for projects selected during the 2020 REG Program Year. The adder was set at 6 cents/kWh and approved for Commercial and Large projects – with a cumulative cap of 6 MW. In advance of the 2021 Program Year, SEA was directed to complete an evaluation of the carport pilot program using data from the 2020 program year, as well as supplemental information derived from additional research and stakeholder interviews. These data were used to conduct a benefit-cost analysis. The results of the BCA were included in the 2020 Program Year Carport Solar Pilot Program Evaluation Report.

In anticipation of the 2022 Program Year, SEA was directed to update the quantitative elements of the benefit-cost analysis (BCA), and present updated results to stakeholders and the DG Board. Updated BCA results were presented to stakeholders via virtual Public Meeting on September 23, 2021. Updated BCA results were provided to the DG Board on September 27, 2021. BCA assumptions and results are discussed in more detail below, and in **JG Schedule 1**. Overall, SEA's mandate was to capture new data (where available), update the BCA assumptions (where possible and applicable), and rerun the benefit-cost analysis.

Methodology for Carport Adder Benefit-Cost Analysis

Who are the members of the consulting team and what are their respective roles in support of the carport benefit-cost analysis?

The Consulting Team is comprised of SEA and its subcontractor, Mondre Energy, Inc. ("Mondre"). SEA collected and analyzed available carport data, conducted cost-based modeling to assess the potential range of carport adder values, and updated the cost-benefit analysis that it first completed in 2020. Mondre conducted interviews with carport developers and municipal planning staff. Mondre developed the interview questions, conducted outreach to stakeholders, and summarized interview findings. A summary of the interview findings is included as **JG Schedule 2**.

Did SEA use the same carport BCA methodology in 2021 that it used in 2020?

Yes. This methodology was developed in 2020 in collaboration with Narragansett Electric. The methodology was explained in detail to stakeholders, the DG Board, and the PUC through SEA's 2020 *Carport Adder Evaluation Report.*

What is the source of the categories of carport benefits and costs?

SEA's analysis draws solely from the benefit and cost categories contained in the Benefit-Cost Framework developed with stakeholders and approved for use by the Commission in Report and Order No. 22851 (issued July 31, 2017).[24] I refer to it hereafter as "the Rhode Island Test".

Does the Rhode Island Test explicitly incorporate any categories of costs and benefits other than direct costs and benefits to ratepayers?

Yes. The Rhode Island Test includes costs and benefits: (1) that accrue to the Power System (i.e., to both the regulated utility and its customers), (2) that accrue directly to Customers, and (3) that accrue to Society (i.e., to the citizens of Rhode Island the broader society).

Please summarize your team's approach to quantifying carport benefits and costs in line with the Rhode Island Test.

The BCA includes an evaluation of the following costs (comprised of power system costs), and benefits (both power system and societal benefits) included and described in detail in the Framework:

<u>Costs</u>: Carport policy cost is a function of the Carport Solar adder and the production (kWh) to which it is applied. The Carport Solar revenue requirement is calculated by taking the difference between two CREST model runs – one for the carport project, and one for the otherwise comparable greenfield project. SEA calculated the levelized cost of energy (i.e. revenue requirement) of a commercial carport and the levelized cost of energy of an otherwise comparable commercial greenfield installation. The adder revenue requirement is the difference between the two and is intended to represent the net difference in capital costs, operating costs and production needed to enable carport projects to cover their costs and achieve a reasonable rate of return. The same process is repeated to calculate the adder revenue requirement for large carports. The capacity factor assumptions are the same for the 2020 and 2021 BCAs.

<u>Benefits</u>: Carport policy benefits are a function of avoided interconnection costs, avoided property value loss, and the value of preserving currently-forested acreage in Rhode Island, which includes the value of carbon sequestration and other ecosystem services. The methodology and data sources are consistent between the 2020 and 2021 analyses. Several incremental interconnection cost datapoints were provided by National Grid in September and October 2021 and have been added to the existing methodology. The data values for avoided property value loss, preservation of forested acreage, and other ecosystem services remained constant between the 2020 and 2021 analyses. The estimate of the social cost of carbon was updated. This update is described below.

[24] Available at: http://www.ripuc.ri.gov/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf

All costs and benefits are quantified in **JG Schedule 1.**

Can you describe your understanding of the meaning of benefit-cost ratios associated with a BCA completed using the Rhode Island Test?

Yes. Based on the Framework as approved by the Commission in Order No. 22851, we interpret an investment with a benefit-cost ratio greater than (or equal to) 1.00 as being cost-effective. We interpret an investment with a benefit-cost ratio less than 1.00 as not being cost-effective.

Does your analysis assume that avoided property value loss, the preservation of currently-forested acreage, and other ecosystem services qualify as benefits recognized by the Commission for estimating cost-effectiveness under the Framework?

Yes. Our understanding is that these benefits reside within the category of Conservation and Community Benefits, as outlined in the Framework.

Do you believe these benefits were measured in a manner consistent with the Framework?

Yes. Members of the SEA team shared our BCA methodology with the Commission at a technical session on August 13, 2020.[25] Based on this meeting, we've assumed that the Commission found the benefit and cost categories described above (and incorporated into this and the prior BCA for the 2020 Program Year) to be consistent with the Framework as approved by this Commission in Order No. 22851.

Was supplemental research and analysis conducted to update the carport BCA?

Yes. SEA conducted supplemental research and analysis of regional solar facilities' actual experience with degradation over time. Please refer to the Pre-Filed Direct Testimony of Tobin Armstrong for a detailed description of this analysis. As a result, the degradation assumption for commercial projects has been updated from 0.5% to 0.8% per year. Please note, however, that this change impacts both carport and non-carport projects. The degradation assumption for large projects remains 0.5% per year.

SEA also reviewed the *Avoided Energy Supply Costs in New England 2021* study materials and updated the assumption for the social cost of carbon (from $68/short ton in the 2020 analysis to $128/short ton in the 2021 analysis).

Finally, the carport BCA for commercial solar is a function of the assumed blend of rooftop and ground-mounted installations. In other words, commercial carport installations may occur in lieu of greenfield, ground-mounted installations or rooftop installations (whereas large solar carports are always assumed to avoid greenfield, ground-mounted installations). Based on historical data, the current composition of (awarded) commercial projects is 60% ground-mounted and 40%

---

[25] Sustainable Energy Advantage, LLC. *Technical Meeting: Update Regarding 2020 REG Carport Solar Adder Pilot Analysis*. 13 August 2020, pp. 12-15. Filed as KD Schedule 2 in Docket 5088. Available at: http://www.ripuc.ri.gov/eventsactions/docket/5088%20RE%20Growth%202021%20-%20NGrid%20&%20DGBoard/KD%20Schedule%202%20-%20OER%20&%20DG%20Board%20PUC%20Technical%20Meeting%20Presentation_FINAL%20(As%20Filed).pdf

roof-mounted. SEA established this baseline by analyzing an updated list of all commercial REG awards through the second open enrollment of 2021. All assumptions are quantified in **JG Schedule 1.**

Did your team conduct supplemental interviews to update the Carport analysis?

Yes. Mondre Energy conducted supplemental interviews with seven (7) developers and nine (9) municipalities to ascertain both quantitative and qualitative impacts of market conditions on near-term (i.e. 2022) carport development. Mondre questioned developers on whether they intended to participate in RI's carport program, their view of the competitiveness of REG incentives compared to solar incentives in other New England States, and the relative ease or difficulty of doing business in RI. Mondre questioned municipalities related to solar ordinances, permit applications submitted since last year, and shifts in public sentiment about solar and land use issues over the past year. Mondre also asked municipalities about their own carbon neutrality targets and how the REG program could support these goals. However, none of the surveyed municipalities have net zero carbon goals. Supplemental interview responses are summarized in **JG Schedule 2.**

Did SEA collaborate with Narragansett Electric Company staff while updating the benefit-cost analysis?

Yes. As a result of the public policy adder process outlined in R.I. Gen. Laws § 39-26.6-22, SEA deemed it critical to work closely with Narragansett Electric to ensure that both entities used a consistent approach to evaluating the costs and benefits of a carport adder under the REG Program. As a result, SEA first collaborated with Narragansett Electric in 2020 to *design* its cost-benefit analysis and aggregate the necessary supporting inputs. SEA collaborated with National Grid again in 2021. Company staff reviewed the results of SEA's benefit-cost analysis, in both 2020 and 2021, prior to the stakeholder meetings in which they were discussed.

<u>Summary of Findings: Carport Adder Benefit-Cost Analysis & Stakeholder Outreach</u>

How did SEA calculate the 'incremental revenue requirement' for carport projects?

SEA used the same methodology that was deployed for the 2021 Program Year carport analysis. In summary, SEA conducted cost-based modeling using the CREST model. We ran multiple scenarios to account for a range of costs and production factors. This resulted in four (4) sets of results: Low Cost/High Production, Low Cost/Low Production, High Cost/High Production, and High Cost/Low Production.

Did SEA update the 'incremental revenue requirement' analysis for carports under current market conditions?

Yes.

What methodology did SEA use to update the 'incremental revenue requirement' analysis?

SEA calculated the incremental revenue requirement (i.e., adder requirement) for three different solar carport sizes using the same methodology and under the same four cost and production scenarios deployed in its prior analyses and described above.

Were draft results presented to stakeholders?

Yes. Draft results were presented to stakeholders on September 23, 2021 and are included in **JG Schedule 1**.

What were the final results, and how do they compare to the adders from 2020 and 2021?

Final results – updated to reflect data from the Second Enrollment Period of the 2021 Program Year – were calculated in November 2021 and are summarized in **JG Schedule 3** and also in **JG Schedule 4**. In summary, the calculated Carport adder revenue requirement under current market conditions ranges between 8.2 and 12.2 cents/kWh. By comparison, the carport adder was 6 cents/kWh for the 2020 Program Year and 5 cents/kWh for the 2021 Program Year.

Did SEA update the benefit-cost analyses for carports under current market conditions?

Yes.

What methodology did SEA use to update the benefit-cost analyses?

SEA used the same methodology that was developed, in collaboration with Narragansett Electric, for the 2021 carport analysis and modeled after the Rhode Island test established in Docket 4600.

For what categories were cost-benefit calculations completed?

SEA completed benefit-cost calculations for Commercial I (>250-500kW), Commercial II (>500-1,000kW), and Large Solar (>1,000-5,000kW) across four cost and production scenarios.

Were draft benefit-cost analysis results presented to stakeholders?

Yes. Draft results were presented to stakeholders on September 23, 2021 and are included in **JG Schedule 1**.

Using this methodology and approach, did any of the categories yield benefit-cost ratios greater than 1.0 for the Base Case?

Yes.

What were the base case benefit-cost ration results?

Final Base Case results – which represent the 'Low Cost, High Production' scenario – include benefit cost ratios 1.68 for Commercial Solar I, 0.89 for Commercial Solar II, and 0.44 for Large Solar. The associated adder values are 8.2 ¢/kWh for Commercial I & II, and 8.3 ¢/kWh for

Large Solar. These results were updated to reflect data from the Second Enrollment Period of the 2021 Program Year and are summarized in **JG Schedule 4** and in **JG Schedule 5**. The Base Case assumes a 2.5% (societal) discount rate.

Did SEA test the sensitivity of the BCA ratio to the carport adder revenue requirements calculated for each of the other scenarios?

Yes. **JG Schedule 6** summarizes the adder value and benefit-cost ratio results for all cases.

Did any of the sensitivities evaluated yield benefit-cost ratios greater than one? (In other words, cases in which benefits exceeded costs?)

Yes. Both the 'High Benefits, Low Costs' and 'High Benefits, High Costs' cases demonstrate benefit-cost ratios greater than 1.00 for the Commercial I carport category.

Are any non-energy benefits expected from Carport Solar projects that were not quantified in the 2020 or 2021 analysis?

Yes. Economic development benefits are expected to derive from the labor intensity of carports relative to greenfield installations, the avoided cost of snow clearing, and reduced operating expenses at Narragansett Electric. Carport hosts are also expected to benefit from the publicity value of renewable energy, which may contribute to customer acquisition and/or loyalty.

If quantified and included, would these additional benefits increase the calculated benefit-cost ratio of each scenario?

Yes. Without additional analysis, however, it is not possible to estimate the exact impact on each cost-benefit ratio.

<u>**Adder Values Associated with Specific Benefit-Cost Ratios Under Docket 4600 "Rhode Island Test"**</u>

Did SEA calculate the adder values necessary to achieve specified benefit-cost ratios, regardless of whether those adder values matched your team's estimate of the incremental revenue requirement of an eligible Carport Solar project?

Yes. Following Narragansett Electric's decision to discontinue the pilot program, two solar industry stakeholders (specifically, the Northeast Clean Energy Council and Oak Square Partners) filed comments suggesting that a Carport Solar adder could be set at a value lower than the incremental capital and operating costs of Carport Solar projects included in the Draft BCA results in **JG Schedule 1**. We attach the written comments from and the Northeast Clean Energy Council and Oak Square Partners as **JG Schedule 7** and **JG Schedule 8**.
Subsequently, and at OER's request, SEA calculated the Carport Solar adder values for Commercial and Large Solar projects (in cents per kWh) necessary to achieve benefit-cost ratios of 1.0, 2.0 and 3.0 under the Rhode Island test established in Docket 4600. These values represent the adders that enable specified benefit-cost ratios, while holding the estimated benefits

(described earlier in this testimony) constant. These values are not intended to represent the revenue required to recover the incremental cost of actual Carport Solar projects in Rhode Island.

Please describe the methodology used to calculate these adder values.

These values were calculated by taking the benefits estimated (by category) earlier in this testimony and solving for the adder values that resulted in specified benefit-cost ratios. In other words, estimated benefits and the benefit-cost ratios are inputs, and the required adders are calculated outputs. By comparison, the original benefit-cost analysis (presented earlier in this testimony) estimates both incremental cost and incremental benefit as inputs, and then calculates the benefit-cost ratio as an output.

What were the adder value results of this analysis, for both Commercial and Large Solar Carport projects?

For Commercial Solar I projects, achieving benefit-cost ratios of 1.0, 2.0 and 3.0 requires Carport Solar adders of 13.75 cents/kWh, 6.90 cents/kWh and 4.60 cents/kWh, respectively. For Commercial Solar II projects, achieving benefit-cost ratios of 1.0, 2.0 and 3.0 requires Carport Solar adders of 7.30 cents/kWh, 3.66 cents/kWh and 2.44 cents/kWh, respectively. For Large Solar projects, the same ratios can be achieved with adders of 4.00 cents/kWh, 2.00 cents/kWh and 1.34 cents/kWh, respectively. These adder values can also be found in **JG Schedule 9**.

Does this conclude your testimony?

Yes.

JG Schedule 1: SEA Presentation at September 23, 2021 REG Program Stakeholder Meeting

See file named: JG Schedule 1 - RI_REG_MTG_re_Carport_Adder_Final_09232021.pdf

JG Schedule 2: Summary of Supplemental Interview Findings

Developer Interview Notes

Topic 1: Solar ground-mount and solar carport development activity in Rhode Island

Developer 1	Developer is no longer active in Rhode Island. Developer had an active project in 2020, but because of an interconnection approval process that took more than one year, and which included successive cost increases that eventually pushed the total cost over the REG program threshold, the project is no longer under development. The developer opines that because interconnection costs are born by the developer (and not the ratepayer), the interconnection cost ceiling is arbitrary and should be removed.
Developer 2	The developer is not active in Rhode Island. Steel prices have more than doubled since 2020, creating increased cost pressure. When combined with other costs of doing business in Rhode Island, the market is not viable for them. They have identified more feasible development prospects in other states. The developer is disappointed in the 5 cent adder in Rhode Island vs. 6 cents in Massachusetts. The developer is actively pursuing carports in Washington DC and in New Jersey where incentives are higher.
Developer 3	Developer is pursuing some ground-mounted projects in Rhode Island, but no carports because the revenue (including the adder) does not support their costs.
Developer 4	The developer is not pursuing carport projects in Rhode Island
Developer 5	Developer is pursuing one carport and multiple ground-mounted projects in Rhode Island. Projects range from 2.5 to 5 MW.
Developer 6	Developer has rooftop and ground mount experience in multiple states. Carport experience in New Jersey and California. Not currently active in Rhode Island because incentives are stronger in other markets.
Developer 7	Developer is not actively pursuing solar projects in Rhode Island. Developer has over 100 solar projects completed or under development in New Hampshire and Massachusetts. Developer has 50 MW of carport projects throughout the Northeast. Developer is not active in Rhode Island because the MW allocation makes the annual market too small to justify entry. Developer observes that U.S. Steel costs are currently about 13c/kWh.

<u>Topic 2</u>: The competitiveness of REG incentives versus solar incentives in other New England states

Developer 1	Developer observes that the REG program is small, but it still generates significant price competition. The Massachusetts market is much larger, allowing for more significant allocations over time, and more certainty regarding the realized incentive. Developer expressed concern that the REG interconnection cost ceiling was set without the opportunity for stakeholders to participate and comment, and without any grandfathering or sunset provision to protect existing projects into which substantial capital investments had already made. The perverse result is that interconnection cost determines the winner, not total project costs. In other words, a project with low interconnection cost will win even if project costs are higher. Developer observes that the 5c/kWh REG adder is needed just to cover carport steel costs versus other solar. Developer opines that an open forum should be added to allow stakeholder guidance for REG programmatic changes.
Developer 2	Developer opines that the REG incentive price is not increasing fast enough to track rising steel prices.
Developer 3	Current focus is on ConEd (20 to 22c/kwh for carport solar in year 1) and New Jersey (12 c/kW to 15 c/kWh adder for 15 years). Carport solar costs are rising because of steel prices.
Developer 4	Developer states that the REG carport adder is too low to make carport solar projects financially attractive. Master electricians, required to supervise laborers in RI, are in short supply. Unprecedented EPC costs have reached $1.20/watt. Shipping costs have increased by a factor of four. A 400-watt panel that cost 35 cents/watt in 2020 was 44 c/watt in Q1 2022. Racking costs are up 15%. Developer believes 4 to 5 MW is a workable project size. Best incentive is a grant to cover up-front costs (e.g., the 90 c/watt grant in New York). Developer recommends the REG carport adder be converted to a sliding scale based on kW capacity. Developer states that projects in RI are not being developed because of economics. The REG feed-in tariff is valuable, but labor costs are high, and the adder is low.
Developer 5	For carport projects less than 1 MW, the REG adder is too low because steel prices are going up.
Developer 6	Developer observes that the REG carport adder went from 6c/kWh to 5 c/kWh but the cost of steel has increased significantly. Developer finds enrollment periods limiting, and prefers rolling process found in other states. Developer finds the REG bidding process skewed to benefit larger projects, which can take up all available capacity. There is no incentive to develop carport solar in Rhode Island over Massachusetts. In MA, the carport adder is 6 c/kWh in order to discourage greenfield development (to preserve forested acres). In MA, Eversource offers 23 c/kWh + 6 c/kWh adder = 29 c/kWh. In RI, 18 c/kWh + 5 c/kWh REG adder = 23 c/kWh. RI REG adder should b 8 c/kWh.
Developer 7	Developer observes increased competition in RI leading to increased completion risk. Developers are proposing prices that don't support project financing and completion. This does not serve the industry in the long-run. It just frustrates project hosts (and investors) when projects are not able to support their costs and must be abandoned.

Topic 3: The ease of doing business in Rhode Island

Developer 1	The pace of development in Rhode Island is very slow compared to New Jersey or New York, but similar to some other states.
Developer 2	The process varies from town to town. Some towns are more pro-solar than others. State-wide siting standard would be helpful. In their experience, most areas in Rhode Island are against ground-mounted solar. Failed agricultural farms results in lots of land available for solar but permitting is difficult. In southern RI, interconnection is the biggest problem. It is a very long process to get interconnection approval: 4 to 6 months for distribution level study then another 6 to 12 months for ISO interconnection. Developer has one projects that took 3 years to get ISO interconnection approval.
Developer 3	Developer observes poor solar economics and significant permitting challenges for ground-mounted solar. As a result, they are not currently pursuing solar opportunities in Rhode Island.
Developer 4	In developer's experience, "everywhere is easier than Rhode Island, except Washington D.C." Developer opines that, as a practical matter, fire departments have full discretion to reject projects. Specific guidance and boundaries are needed here to support future development.
Developer 5	Developer is active in Rhode Island but can't make carport projects economic with current carport adder. Municipalities are streamlining solar permitting in already disturbed areas. This is helpful.
Developer 6	Developer believes that Rhode Island grid can't handle additional solar required to meet state goals. In NJ, interconnection approval takes 6 to 8 weeks. In Rhode Island it takes 6 to 8 months. In the towns, backlash against ground-mounted solar is affecting carport solar as well. The implementation in municipalities and at National Grid appears inconsistent with the state's renewable energy objectives.
Developer 7	Developer is not active in Rhode Island. Developer believes the state should provide direction to municipalities on how carport solar is treated for permitting to reduce project completion risk.

Municipality Interview Notes

Topic 1: Status of solar ordinances

Bristol	A solar ordinance was adopted in 2020. If carport solar covers more than 25 or 50 vehicles (depending on location) or covers 10,000 SF, then planning review is required. Otherwise, carport solar is an accessory use.
Burrillville	Solar ordinance was changed to require a different permitting path based on land use requirements instead of installed solar capacity.
Cranston	Council amended solar ordinance to allow ground mounted solar only in industrial zones. Carport solar less than 200 kW is an accessory use. Over 200 kW requires development plan review. Rooftop solar is by-right.
Cumberland	No solar ordinance.
Hopkinton	Old solar ordinance was replaced in April 2021. No commercial solar is allowed. Residential is accessory use.
Middletown	Ground-mounted solar ordinance that is in effect is being updated to include carport solar. Rooftop solar is by-right.
Narragansett	No solar ordinance.
Richmond	A solar ordinance is in place that applies to carport and ground mounted systems. Rooftop solar is permitted by-right.
Woonsocket	No solar ordinance.

Topic 2: Permit applications submitted since last year for carport and ground-mount

Bristol	None
Burrillville	One carport solar application has been received for a 0.5 acre truck parking area. 6 applications are in process for ground-mounted solar.
Cranston	None
Cumberland	None
Hopkinton	None
Middletown	None
Narragansett	None
Richmond	None
Woonsocket	None

Topic 3: Intersection of permitting and public acceptance; shifts in public sentiment

Bristol	An ordinance was proposed that would have allowed residential ground-mounted solar at larger homes, but it was rejected. Only roof-mounted residential solar is allowed.
Burrillville	Solar is allowed in commercial or industrial zones only. No large solar on farms or residences. Developers can propose solar on unused brownfield sites.
Cranston	Landfill solar is now allowed. Substantial push-back on clearcutting for ground-mounted solar.
Cumberland	No discernable shifts in public sentiment.
Hopkinton	Sentiment among many is that too much solar has been installed already. Abutters are most vocal. New solar may see opposition.
Middletown	Allowance for carport solar on agricultural land has been discussed. Evaluation of carport solar impact on impervious coverage is an issue.
Narragansett	There has been backlash against land-clearing for solar and the resultant impact on wildlife and stormwater.
Richmond	No discernable shift. Solar is allowed in commercial or industrial zones. Richmond is mostly residential and agricultural. Solar is discouraged in residential areas.
Woonsocket	Solar is increasingly adversarial because of land-clearing for ground-mounted systems. Anti-development sentiment now targets solar. Some solar ordinances are restrictive. More broadly, local and state policy on renewable energy appears out of alignment.

Topic 4: Policies within your jurisdiction to meet carbon neutral, net zero targets and how the REG program could support these policies.

Bristol	No net zero targets.
Burrillville	No net zero targets.
Cranston	No carbon neutrality goals in zoning policies. There has been push-back on including solar in the comprehensive plan.
Cumberland	No net zero targets.
Hopkinton	No net zero targets. There is an unofficial moratorium on solar. Town is split on solar issues.
Middletown	No net zero targets. Big issues are the impact of overdevelopment on the rural character of the town and water & sewer issues.
Narragansett	No net zero targets.
Richmond	No net zero targets. No Master Plan revisions are on the horizon.
Woonsocket	No net zero targets.

JG Schedule 3: Incremental Revenue Requirement, by Scenario

Size Category	Modeled Size (kW)	Low Cost/ High Production	Low Cost/ Low Production	High Cost/ High Production	High Cost/ Low Production
Commercial I (>250-500kW)	500	8.2	11.4	8.9	12.2
Commercial II (>500-1,000kW)	1,000	8.2	11.0	8.9	11.8
Large (>1,000-5,00kW)	5,000	8.3	11.7	8.3	10.7

JG Schedule 4: Carport Adder and Benefit-Cost Analysis, Revised November 2021

See file named: JG Schedule 4 - RI_REG_Carport_Adder_Final_Updated_November 2021.pdf

JG Schedule 5: Base Case Results for Carport Benefit-Cost Analysis

Case	Project Category	NPV Total Benefits ($/kW)	NPV Total Costs ($/kW)	Benefit-Cost Ratio
Low Benefits, Low Costs	Commercial I (>250-500kW)	$610	$1,370	0.45
	Commercial II (>500-1,000kW)	$357	$1,370	0.26
	Large (>500-1,000kW)	$339	$1,422	0.24
High Benefits, Low Costs	**Commercial I** (>250-500kW)	**$2,304**	**$1,370**	**1.68**
	Commercial II (>500-1,000kW)	$1,224	$1,370	0.89
	Large (>500-1,000kW)	$629	$1,422	0.44
Low Benefits, High Costs	Commercial I (>250-500kW)	$610	$1,526	0.40
	Commercial II (>500-1,000kW)	$357	$1,526	0.23
	Large (>500-1,000kW)	$339	$1,585	0.21
High Benefits, High Costs	**Commercial I** (>250-500kW)	**$2,304**	**$1,526**	**1.51**
	Commercial II (>500-1,000kW)	$1,224	$1,526	0.80
	Large (>500-1,000kW)	$629	$1,585	0.40

JG Schedule 6: Sensitivity Analysis for Carport Solar Benefit-Cost Analysis

Case	Project Category	Parameter	Case/Value		
			Low Cost/Low Production	High Cost/High Production	High Cost/Low Production
Low Benefits/ Low Costs	Commercial I (>250-500kW)	Adder Value (¢/kWh)	11.40	8.90	12.20
		B/C Ratio	0.32	0.41	0.30
	Commercial II (>500-1,000kW)	Adder Value (¢/kWh)	11.00	8.90	11.80
		B/C Ratio	0.19	0.24	0.18
	Large (>1,000-5,000kW)	Adder Value (¢/kWh)	10.70	8.30	10.70
		B/C Ratio	0.18	0.24	0.18
High Benefits/ Low Costs	**Commercial I** (>250-500kW)	Adder Value (¢/kWh)	11.40	8.90	12.20
		B/C Ratio	**1.21**	**1.55**	**1.13**
	Commercial II (>500-1,000kW)	Adder Value (¢/kWh)	11.00	8.90	11.80
		B/C Ratio	0.67	0.82	0.62
	Large (>1,000-5,000kW)	Adder Value (¢/kWh)	10.70	8.30	10.70
		B/C Ratio	0.34	0.44	0.34
Low Benefits/ High Costs	Commercial I (>250-500kW)	Adder Value (¢/kWh)	11.40	8.90	12.20
		B/C Ratio	0.29	0.37	0.27
	Commercial II (>500-1,000kW)	Adder Value (¢/kWh)	11.00	8.90	11.80
		B/C Ratio	0.17	0.22	0.16
	Large (>1,000-5,000kW)	Adder Value (¢/kWh)	10.70	8.30	10.70
		B/C Ratio	0.17	0.21	0.17
High Benefits/ High Costs	**Commercial I** (>250-500kW)	Adder Value (¢/kWh)	11.40	8.90	12.20
		B/C Ratio	**1.09**	**1.39**	**1.01**
	Commercial II (>500-1,000kW)	Adder Value (¢/kWh)	11.00	8.90	11.80
		B/C Ratio	0.60	0.74	0.56
	Large (>1,000-5,000kW)	Adder Value (¢/kWh)	10.70	8.30	10.70
		B/C Ratio	0.31	0.40	0.31

JG Schedule 7: Northeast Clean Energy Council Public Comment to DG Board Regarding Carport Solar Non-Continuation

See file named: JG Schedule 7 NECEC Carport Adder Comments 10.25.21.pdf

JG Schedule 8: Oak Square Partners Public Comment to DG Board Regarding Carport Solar Non-Continuation

See file named: JG Schedule 8 Oak Square Partners comments on carport adder.pdf

JG Schedule 9: Carport Adder Values Needed to Achieve Specific Benefit-Cost Ratios (BCR) Under Docket 4600 "Rhode Island Test"

Carport Solar Class	Adder Value (¢/kWh) for BCR of 1.0	Adder Value (¢/kWh) for BCR of 2.0	Adder Value (¢/kWh) for BCR of 3.0	Base Case, for comparison. Cost-Based Adder / BCR
Commercial I (>250-500kW)	13.75	6.90	4.60	8.2 / 1.68
Commercial II (>500-1,000kW)	7.30	3.66	2.44	8.2 / 0.89
Large (>1,000-5,000kW)	4.00	2.00	1.34	8.3 / 0.44

Pre-Filed Direct Testimony of Tobin Armstrong – Sustainable Energy Advantage

I, Tobin Armstrong, hereby testify under oath as follows:

Please state your name, employer and title.

My name is Tobin Armstrong. I am employed by Sustainable Energy Advantage, LLC ("SEA") as Senior Analyst. I also lead the firm's distributed generation market modeling.

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

I have seven years of experience related to renewable energy policy, and three years of professional experience with modeling solar energy production. At SEA, I lead the company's distributed generation market molding and am the lead modeler for our Massachusetts Solar Market Study (MA-SMS). Both of these roles require expertise in modeling solar energy production, with recent emphasis on the factors influencing solar production degradation.

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.

How do solar degradation inputs contribute to SEA's ceiling price analysis?

SEA's discounted cash flow analysis assesses the expected revenue generated by a project as a function of the project's energy production. As such, solar degradation rates directly influence the necessary incentive payment derived by SEA's analysis, as a higher degradation rate would result in less production over the life of the project, and thus a higher per/kWh incentive payment required to ensure the project is financially viable.

What solar degradation assumptions were previously made in support of the 2021 Program Year?

SEA previously assumed an annual degradation rate of 0.5% for all solar projects. This rate was previously adopted as it is the industry standard for PV module degradation.[26]

Do you believe that these inputs continue to represent the best and most accurate account of in-practice degradation? Why or why not?

No. Although a degradation rate of 0.5% may accurately reflect PV module degradation in a controlled setting, in-practice degradation is influenced by several other factors that contribute to higher realized degradation rates. These factors include accelerated module degradation

[26] See Jordan, D., Kurtz, S., VanSant, K., and Newmiller, J., "Compendium of photovoltaic degradation rates," Prog. Photovoltaics 24 (2016)

stemming from partial shading and weathering of the panel surface.[27]

Has SEA analyzed in-practice degradation rates?

Yes. SEA recently conducted an in-depth analysis of degradation rates in Massachusetts which confirmed that real-world degradation rates are in excess of 0.5%. SEA's analysis found average degradation, based on project size, to be as follows: for projects 0-25 kW_{DC}, average degradation was 1.51%, for projects >25-1 MW_{DC}, average degradation was 1.08%, and for projects 1-5 MW_{DC}, average degradation was 0.56%.

What data did SEA use in its updated analysis?

SEA's analysis utilized a dataset containing the monthly production of all solar facilities operating in Massachusetts from 2010 to 2019 which was provided by the Massachusetts Department of Energy Resources (DOER) in March of 2021 in response to a public records request filed by SEA.

Does SEA believe that this data is appropriate for assessing solar production in Rhode Island? Why or why not?

Yes. SEA believes that this data set is an excellent proxy for the production characteristics of solar facilities located in Rhode Island given the similarities in climate between Rhode Island and Massachusetts. Factors impacting degradation, including cloud cover, snowfall, vegetation management, dust, and operations and management (O&M) practices are likely to be very similar across states.

Please describe the process that SEA utilized to develop the updated solar degradation inputs used in support of 2022 Program Year ceiling price development.

A high-level overview of SEA's methods are as follows. Projects in the dataset were categorized into the following size bins 0-25 kW_{DC}, >25-1 MW_{DC}, and 1-5 MW_{DC}. The first year of production data from each project was excluded to prevent mid-year commercial operation dates biasing the analysis. In addition, production data from winter months was excluded to prevent the effects of snow cover biasing the analysis. Production data for all projects was adjusted based on an analysis of yearly irradiance (as reported by NASA's Power Data Access View project) to weather-normalize the production data. In other words, the weather-normalization increased production in years in which irradiance was lower than average and decreased production occurring in years in which irradiance was higher than average, so that the results are not biased by year-to-year variation in weather. SEA then calculated the average year-over-year percent change in the weather-normalized production for projects in each size bin. For a complete account of SEA's methods, please see SEA's **July 27 presentation** to stakeholders (JK Schedule 1), pages 35 to 39.

[27] Partial shading has been found to accelerate PV degradation – see Carlos Olall et. al, *Mitigation of Hot-Spots in Photovoltaic Systems Using Distributed Power Electronics*, energies (2018)

Have SEA's findings been corroborated by any third-party analysis? If yes, how so?

Yes. A recent meta-analysis undertaken by kWh Analytics (a well-respected data analytics firm serving a broad array of solar market participants, from developers to financiers and insurance companies) found (similarly to SEA) that degradation rates for smaller projects are more pronounced than for larger projects.[28] The above meta-analysis indicates that, at minimum, estimates in excess of 1% appear to better represent degradation rates for small to medium-scale DG projects. In addition, a recent study by the National Renewable Energy Laboratory (NREL) analyzed production data from 21 GW_{DC} of utility-scale solar projects across the United States, and found that degradation rates in excess of 1% are typical (with an average of 1.3%).[29]

How did SEA calculate the values that were ultimately adopted for inputs to the proposed 2022 ceiling prices?

SEA adopted a middle point between its previous degradation inputs and the values derived from its analysis for all solar classes other than Large Solar (1-5 MW), in which SEA did not change its previous value of 0.5%.

Why did SEA take this approach?

In our experience, in-practice degradation is a function of both sub-optimal technological performance relative to expectations, siting considerations, as well as operations and maintenance (O&M) practices. If O&M practices are performed in an optimal manner, this should minimize solar degradation. Given that our team's analysis relied on historic production data from Massachusetts that could not be cross-referenced with the type of O&M practices employed, the degree to which sub-optimal O&M practices contributed to the degradation rates revealed through the analysis is not currently known.

However, in our opinion, it is likely that, even given optimal O&M practices, degradation will likely exceed 0.5%/year. Indeed, NREL's study, referenced above, found an average degradation rate of 1.3% for utility-scale projects that are likely to have optimal O&M practices employed. As such (and in light of a lack of variables to overlay on the instant data to control for poor O&M practices), SEA's approach was intended to balance the goal of incenting optimal O&M with ensuring that degradation rates utilized in modeling reflected a realistic outcome for real-world project performance.

However, different scales of solar have different O&M practices that project owners can be reasonably expected to employ. For instance, it is SEA's observation that for smaller-scale solar PV projects (especially those less than or equal to 25 kW), operations and maintenance activities are typically offered as a premium package relative to the basic installation cost of the project, and thus are often set up as an offer that many (if not most) participating customers will decline at closing (similar to extended or enhanced dealer warranties and/or service contracts for

[28] kWh analytics, *Solar Risk Assessment: 2021*

[29] Mark Bolinger et. al., *System-level performance and degradation of 21 GWDC of utility-scale PV plants in the United States*, J. Renewable Sustainable Energy 12 (2020)

passenger vehicles). As such, it would be unreasonable to hold small solar facilities to the same O&M standards as large solar facilities in determining what reasonably optimal O&M (and thus a reasonable degradation rate) constitutes. In addition, un-ideal siting, which is more common for smaller facilities, is also likely to produce accelerated degradation if it results in partial shading, which cannot be addressed through optimal O&M practices. As a result, SEA believes that it is reasonable to adopt higher degradation rates for smaller facilities as compared to larger facilities.

Please describe the revised degradation inputs your team ultimately settled on for the 2022 proposed ceiling prices.

In light of these consideration, our team recommends prices that utilize the prior inputs for Large Solar projects, given the minor differences between the degradation rates produced by its analysis (0.56%) and the rate previously utilized (0.5%). For all other classes, SEA adopted a midpoint between its previous degradation inputs and the values derived from its analysis as a conservative response to uncertainty regarding the degree to which degradation rates are under the project owner's control.

As such, SEA adopted the following rates: for projects 0-25 kW_{DC}, 1.0%, for projects >25-1 MW_{DC}, 0.8%, and for projects 1-5 MW_{DC}, 0.5%.

Do you believe that this approach balances the key objectives of utilizing an emerging industry consensus regarding the limits of solar PV technology with the need to ensure ratepayers are not subsidizing poor O&M practices?

Yes, I do.

Does this conclude your testimony?

Yes.