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

NOVEMBER 29, 2021

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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	≤ 5 MW_{AC}
Anaerobic Digestion	≤ 5 MW_{AC}
Small Scale Hydropower	≤ 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	≤ 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

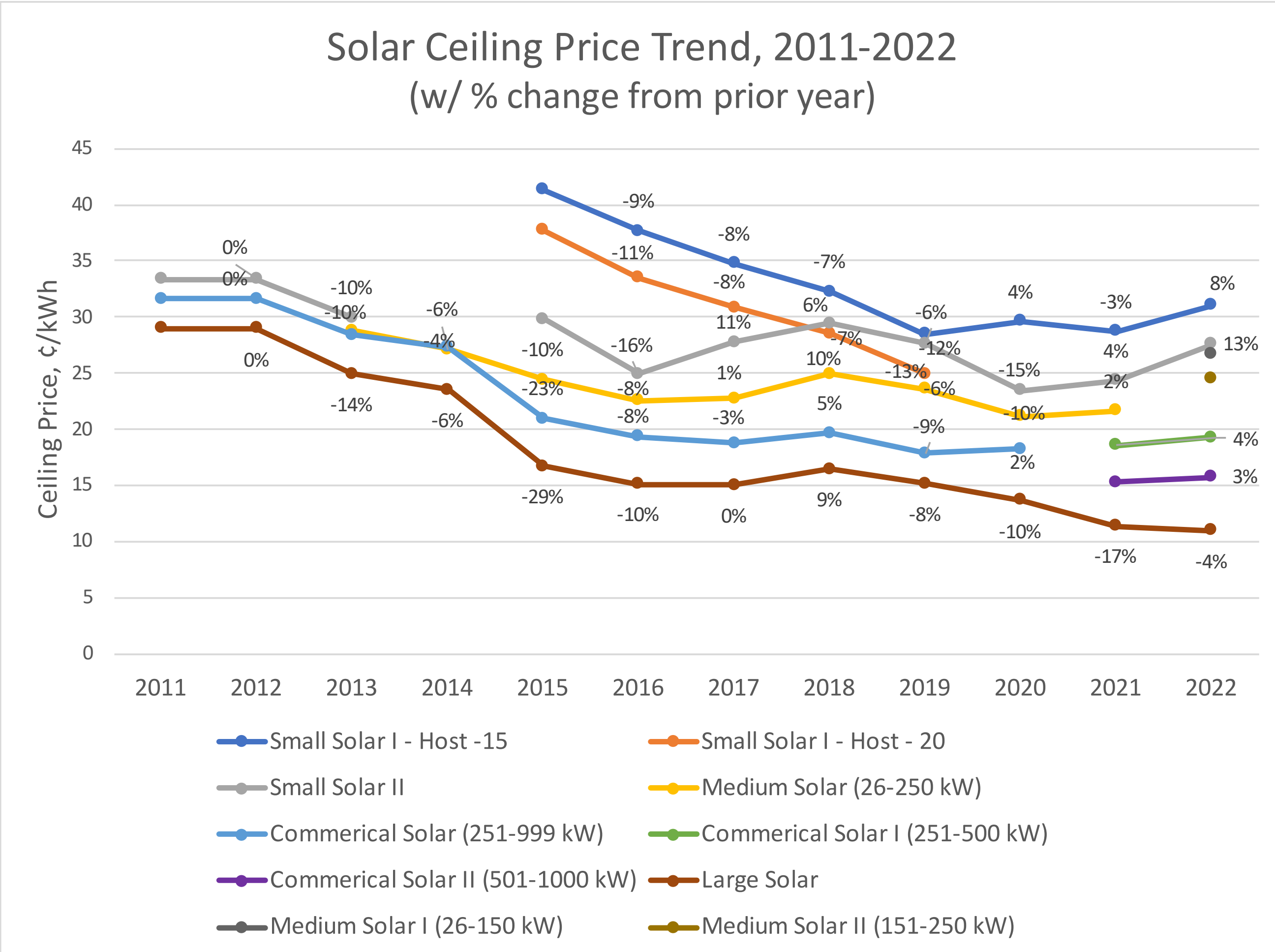


Table 4D - Ceiling Price Trend for Wind

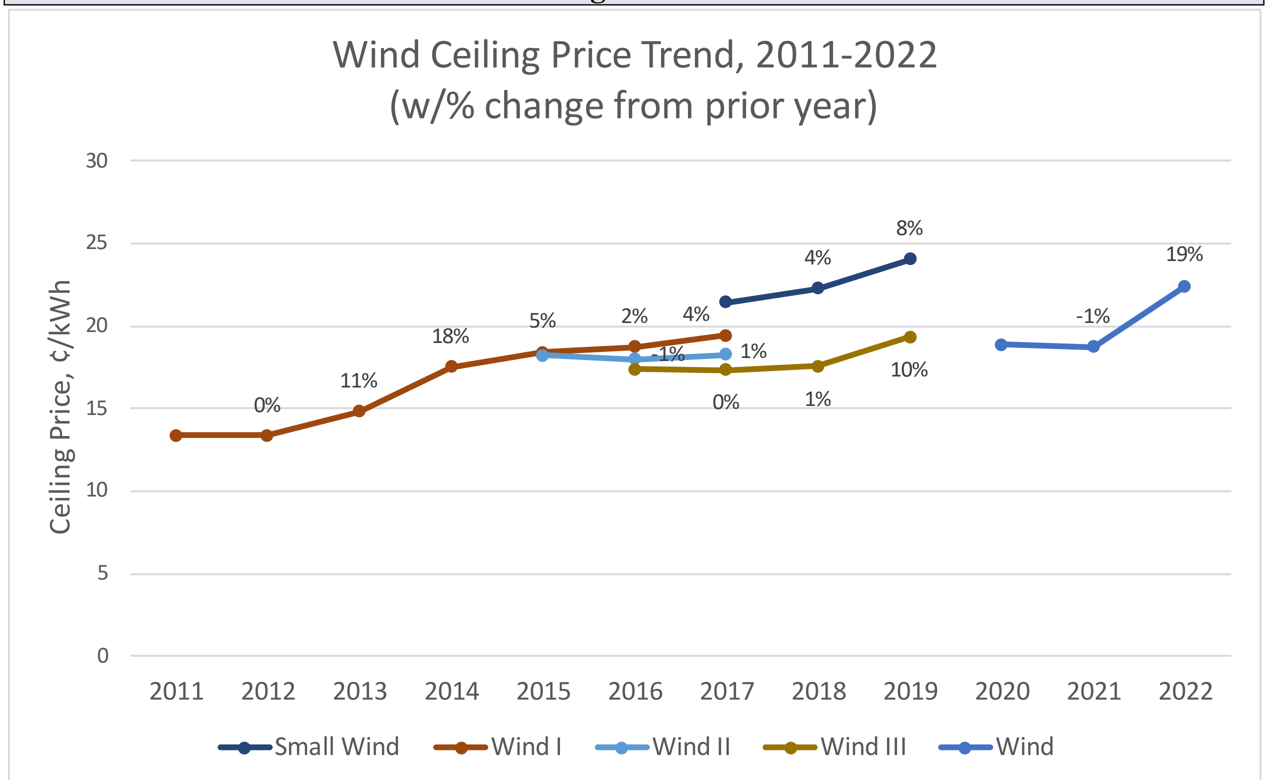


Table 4E - Ceiling Price Trend for Anaerobic Digestion

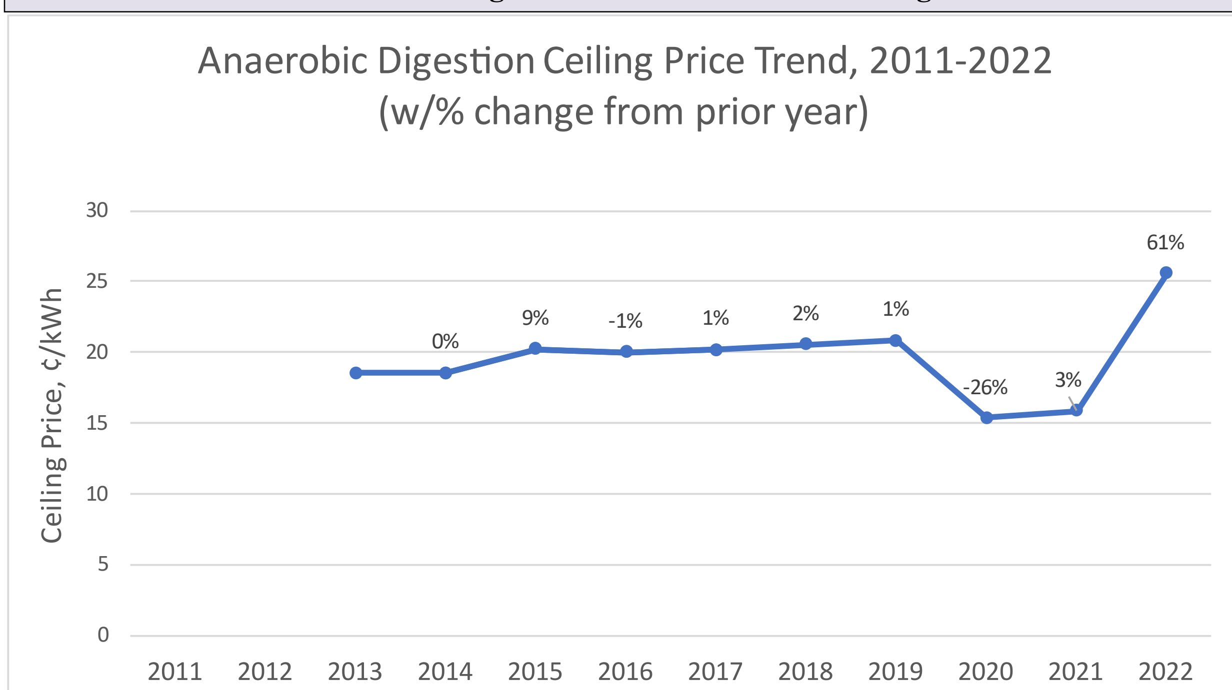
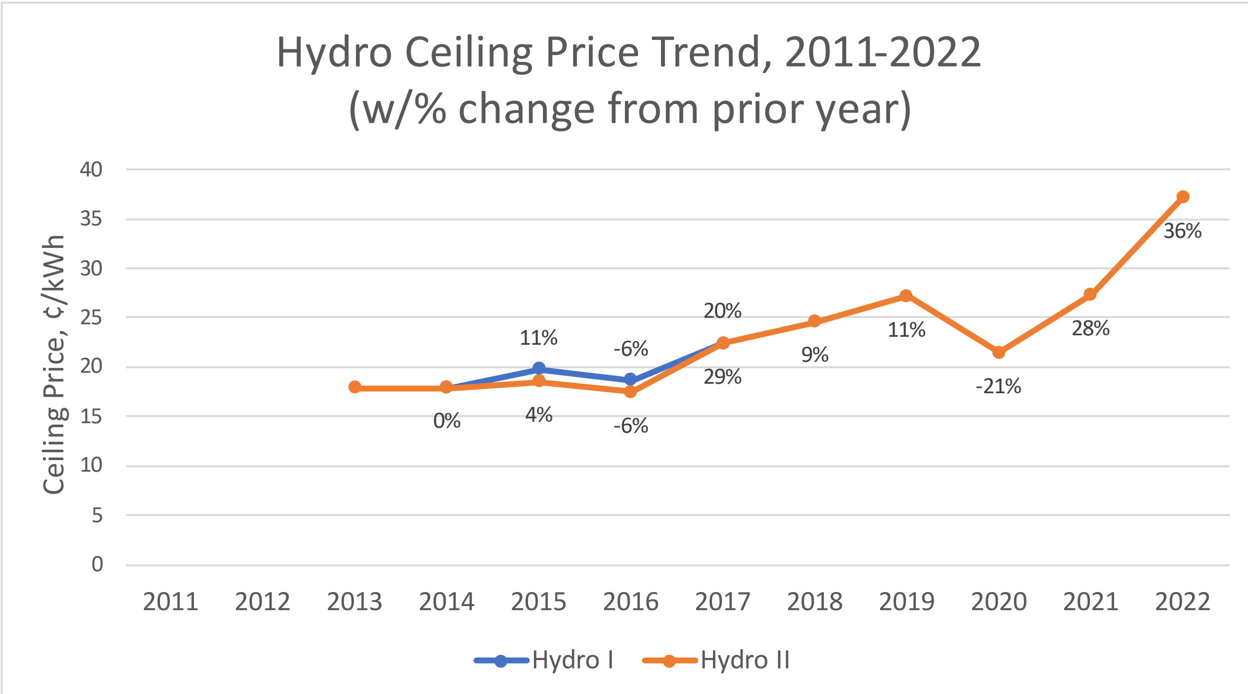


Table 4F - Ceiling Price Trend for Hydropower



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 ($\leq$ 5 MW_{AC})	3.0
Community Remote – Wind ($\leq$ 5 MW_{AC})	
Anaerobic Digestion ($\leq$ 5 MW_{AC})	1.0
Small Scale Hydropower ($\leq$ 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.

Pre-Filed Direct Testimony of Jim Kennerly – Sustainable Energy Advantage

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.

Ceiling Price Development – Stakeholder Engagement Process

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.

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

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.

Drivers of Upward Pressure on Proposed 2022 Solar Ceiling Prices

- *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.

Drivers of Downward Pressure on Proposed 2022 Solar Ceiling Prices

- *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**.

<u>Ceiling Price Development – Changes from 2021 Approved Wind, Hydro and Anaerobic Digestion Prices</u>

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.

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[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, I also believe that:

- (For eligible Non-Solar projects and Solar projects greater than 25 kW_{DC}) 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; and
- (For eligible Solar projects less than or equal to 25 kW_{DC}) Despite the fact that these projects will receive an administratively-set value, the blending of the NREL ATB long-term cost reduction estimate almost fully offsets the increase attributable to the above-described (and relatively extraordinary) market conditions.

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, and proposed selecting the approach that averaged the 14% PVWatts value and the 12.8% value from Narragansett Electric's analysis.

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 that averaging the current 14% capacity factor for Small Solar projects with the 12.8% capacity factor 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 17** 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.

__Interconnection Costs__

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 18** 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 19.**

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 19**.

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 20**) 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>

[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

Does SEA believe that the importance of both policy objectives and cost-effectiveness 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	≤ 5 MW_{AC}
Anaerobic Digestion	≤ 5 MW_{AC}
Small Scale Hydropower	≤ 5 MW_{AC}
Community Remote – Commercial Solar	>250-500 kW_{DC}
	>500-1000 kW_{DC}
Community Remote – Large Solar	>1-5 MW_{DC}
Community Remote – Wind	≤ 5 MW_{AC}

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 – 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 18 – 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 19 – SEA Presentation to Stakeholders on Interconnection Issues

See file named: JK Schedule 19 – SEA Presentation to Stakeholders on Interconnection Issues.pdf

JK Schedule 20 - 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.

<u>Context and Objectives for Carport Adder Benefit-Cost Analysis</u>

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.

<u>Methodology for Carport Adder Benefit-Cost Analysis</u>

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%

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[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.

<u>Topic 3</u>: 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

<u>Topic 3</u>: 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.

<u>Topic 4</u>: 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

<u>Pre-Filed Direct Testimony of Tobin Armstrong – Sustainable Energy Advantage</u>

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.

Sustainable Energy Advantage, LLC

RI Renewable Energy Growth Program: Discussion of Carport Adder and Benefit-Cost Analysis

September 23, 2021

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Carport Adder Analysis

Sustainable Energy Advantage, LLC

Context

PUC Decisions in Docket 5088 (2021)

- Approved one-year continuation of the Carport Solar adder pilot program (through 2021 PY) at an adder value of 5 ₵/kWh, subject to the following conditions:
    - That the distribution interconnection costs of selected projects during the 2021 PY be lower than a two-year rolling capacity-weighted average for that size category; and
    - That selected projects must produce documentation sufficient to verify final costs of the canopy structure and mounting system at the time of Certificate of Eligibility issuance;

- Rejected expansion of Carport Solar adder pilot eligibility to Medium Solar projects

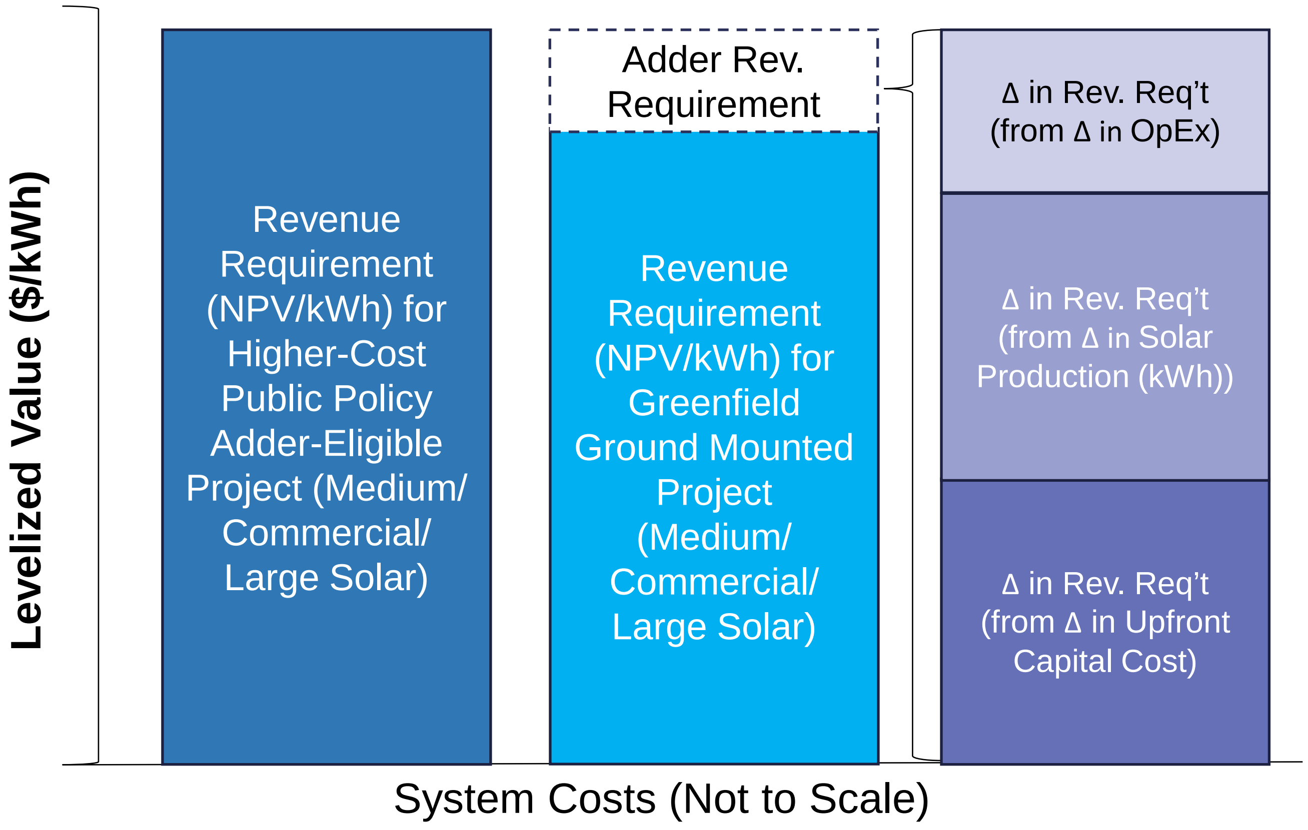
Carport Adder Scope for 2022 Program Year

- Scope: SEA and Mondre Energy were directed to update the 2020 PY Carport Adder program evaluation – including the Docket 4600-based Benefit-Cost Analysis (BCA).

- Objective: To capture new data (where available), provide an updated BCA analysis, and enable OER/ DG Board to make an informed decision on whether to support a permanent Carport Solar adder.

Methodology (1)

How SEA Calculates Proposed RI REG Public Policy Adders



- To set appropriate adder values, we compare the greenfield ground-mounted project to a project expected to create a certain degree of public policy value (e.g. rooftop, carport, LMI, etc.) of the same size
- Projects suspected to offer enhanced public policy value **tend to have incremental capital and operating costs relative to greenfield ground-mounted projects of the same size** (as well as reduced energy production)
- The adder revenue requirement is intended to represent **the net difference in capital costs, operating costs and production needed** to help preferred projects reach investor returns
- To establish these values, SEA undertook a survey of Rhode Island and regional market participants

Methodology (2)

- Case Matrix

Project Type	Size Category	Modeled Size (kW_{DC})	Case #1: Low Cost/ High Production	Case #2: Low Cost/ Low Production	Case #3: High Cost/ High Production	Case #4: High Cost/ Low Production
Carport, Commercial	251-999 kW	500	• **1st Quartile** Upfront Cost • Production @ **Highest End** of Carport Range **(14.6%)** • **Mean** OpEx % Increase	• **1st Quartile** Upfront Cost • Production @ **Lowest End** of Carport Range **(13.1%)** • **Mean** OpEx % Increase	• **3rd Quartile** Upfront Cost • Production @ **Highest End** of Carport Range **(14.6%)** • **Mean** OpEx % Increase	• **3rd Quartile** Upfront Cost • Production @ **Highest End** of Rooftop Range **(13.1%)** • **Mean** OpEx % Increase
Carport, Large	1-5 MW	4,500				

- SEA evaluated information gathered from:
  - National Grid (Open Enrollment data)
  - A survey of solar developers (cost data, permitting and IC information)

REG Carports Selected, & 2021 Cost Data

Enrollment Period	Facility	Location	kWdc	Actual or Target COD	Incremental Carport Cost/kWdc
2020-1	Project 1	[redacted]	[redacted]	4/23/2021 (Actual)	
2020-1	Project 2	[redacted]	[redacted]	8/2022 (Est.)	
2020-2	Project 3	[redacted]	[redacted]	4/2023 (Est.)	
2021-1	Project 4	[redacted]	[redacted]	7/2023 (Est.)	$744.81
2021-1	Project 5	[redacted]	[redacted]	7/2023 (Est.)	~~$1,597.65~~[1]

(1) Project excluded from carport adder analysis due to expected overstatement of “incremental” cost.

Carport Cost Input Assumptions

Commercial Category

Cost Case	Incremental Cost Input	Notes
Low	$1,011	Average of incremental cost from 2021 Open Enrollment bid and publicly available carport quote.
High	$1,277	Publicly available[1] carport quote for 500 kW system

Large Category

Cost Case	Incremental Cost Input	Notes
Low	$1,000	Average of incremental cost from 2021 Open Enrollment bid and publicly available carport quote.
High	$1,254	Publicly available[1] carport quote for 1,000 kW system

(1) https://www.solarelectricsupply.com/commercial-solar-systems/solar-carport

Carport Adder: Revenue Requirement Results

Required Adder Revenue, ¢/kWh

Size Category	Modeled Size (kW)	Low Cost/ High Production	Low Cost/ Low Production	High Cost/ High Production	High Cost/ Low Production
Commercial I	500	7.0	10.5	8.7	12.3
Commercial II	1,000	7.0	10.1	8.6	12.9
Large	5,000	7.5	10.1	9.0	11.8
Weighted Average		*7.4*	*10.1*	*8.9*	*11.9*
Required Adder, Rounded		**7.5**	**10.0**	**9.0**	**12.0**

Carport Adder: Willingness to Pay (WTP)

URI Study: Incorporating Resident Preferences into Policy Recommendations for Utility-Scale Solar Siting in Rhode Island

Table 6: Developing solar siting incentives justified by residents' preferences

			Aggregate WTP/kWh		
Policy Action	**Household WTP**	**Household WTP/kWh**	**Median households within 0.5 miles**	**Median households within 1 mile**	**Median households within 3 miles**
	(1)	(2)	(3)	(4)	(5)
Forest to Commercial	$68.36	$0.00029	$0.07	$0.27	$2.47
Forest to Brownfield	$63.95	$0.00027	$0.06	$0.26	$2.31
Farm to Commercial	$32.54	$0.00014	$0.03	$0.13	$1.18
Farm to Brownfield	$28.13	$0.00012	$0.03	$0.11	$1.02
Fully visible to partly visible	$6.47	$0.00003	$0.01	$0.03	$0.23
Fully visible to not visible	$8.43	$0.00004	$0.01	$0.03	$0.31

URI assumes a 2,000 kWac facility.

Aggregate WTP is a function of household WTP/kWh and # of households within a specified distance. Household WTP/kWh is a function of gross Household WTP and the monthly expected generation from a representative facility.

Benefit-Cost Analysis

Sustainable Energy Advantage, LLC

BCA Methodology: Costs

Docket 4600 "Level"	Docket 4600 Framework Category	Cost or Benefit?	Assessment Approach	Values Utilized	Units	Source
Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Cost	Quantitative	**Incremental upfront capital cost of Carport projects** (associated with Carport structure, and relative to greenfield projects)	$\$/kW_{DC}$	Total project cost estimate supplied by developers to National Grid
Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Cost	Quantitative	**Incremental Carport O&M or other operating expenses** (relative to a greenfield project)	$\$/kW_{DC}$-yr	Incremental research
Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Cost	Quantitative	**Incremental decrease in lifetime production associated with Carport projects** (relative to assumed production from all selected projects)	kWh/ MWh	Incremental research

BCA Methodology: Benefits

Docket 4600 "Level"	Docket 4600 Framework Category	Cost or Benefit?	Assessment Approach	Values Utilized	Input Units	Source
Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Benefit	Quantitative	**Avoided interconnection costs for Carports**, compared to all other REG projects selected in 2020 and the 1st enrollment of 2021	• IC costs on a $/kW_{DC}$ basis	• 2020 National Grid IC cost databases • IC cost from 1st enrollment of 2021
Societal	Conservation and community benefits	Benefit	Quantitative	The **value of preserving forested acres/carbon sequestration**	• Metric Tons per Acre Disturbed	• Value of RI Forests, 2019 Report
Societal	Conservation and community benefits	Benefit	Quantitative	**Non-carbon value of open space/other "ecosystem services"**	Value of historical environmental/conservation easements (as separate from sink value)	SEIA
Societal	Conservation and community benefits	Benefit	Quantitative	**Social Cost of Carbon**	Avoided $/short ton	AESC 2021
Societal	Conservation and community benefits	Benefit	Quantitative	**Value of Ecosystem Services**	$/acre/year	Delaware Valley Regional Planning Commission
Societal	Conservation and community benefits	Benefit	Quantitative	**Avoided Property Value Loss**	$/affected property	University of Rhode Island Cooperative Extension, 2020

Benefits of Carports: Additional Explanation

- Land use benefits from avoiding development of a greenfield project
  - Carbon Sequestration: Use values from RI DEM Value of Forests Study
    - High and low benefit cases vary acreage of forests cleared
  - Ecosystem Services: Uses a study prepared for the Delaware Valley Regional Planning Commission (southeastern PA)
    - Low benefit assumes half the total value quantified in study
  - Avoided Property Value Loss: Based on recent research from URI estimating reduction in value of homes located near greenfield solar
    - Property Value Impacts of Commercial-Scale Solar Energy in MA and RI
    - Low benefit case assumes half of property value impact per home and half the number of homes impacted for Commercial Solar
    - For Commercial Solar, all values are weighted by percent of ground mount projects in past selections

Carport Research: Additional Findings

- Quantitative Findings:
  - “Steel prices have doubled since 2020.”
  - “Steel costs are up 30% since 2020.”
  - “Steel costs are about 13c/kWh.”
  - “Carport EPC costs are about $1.20 per watt.”
  - “The 5c/kWh REG adder is needed just to cover the steel costs for carport solar vs. rooftop.”
  - “Interconnection review took over a year and estimated cost was > $54K ceiling.”
  - “X has carport projects underway in Washington DC and in New Jersey because of higher incentive prices.”
  - “Current focus is on ConEd (20 to 22c/kwh for carport solar in year 1) and New Jersey (12 c/kWh to 15 c/kWh adder for 15 years).”
- Qualitative Findings:
  - “The developer bears interconnection costs, not the ratepayer. The ceiling interconnection cost threshold seemed arbitrary and discriminatory.”
  - “Everywhere is easier than Rhode Island except Washington D.C. Fire departments have full discretion to reject projects.”

NPV of Quantified Benefits

- Total net present value of quantified benefits, assuming a societal discount rate of 2.5%

	Commercial ($/kW)		Large ($/kW)	
	Low Benefits	High Benefits	Low Benefits	High Benefits
Interconnection Cost Savings	$107	$130	$107	$130
Carbon Sequestration	$17	$237	$46	$105
Ecosystem Services	$2	$3	$2	$3
Avoided Property Value Loss	$824	$3,295	$183	$366
Total (Weighted by Avoided Project Type)	**$949**	**$3,665**	**$338**	**$605**

Unquantified Benefits and Uncertainties

- Unquantified Benefits
  - Reduced utility operational expenses related to less complex and costly interconnections
  - Job-related benefits from increased labor-intensity of carports relative to greenfield
  - Avoided cost of snow clearing and other maintenance as a result of shelter from the elements
  - Improved community acceptance driven by lower or no adverse visual impacts and no clearing of trees
  - Branding and publicity value for commercial carport hosts
  - Willingness to pay to preserve open space
- Analysis Uncertainties
  - Very small data set of projects participating in Carport Adder Pilot
  - Assumptions of baseline: defining a hypothetical avoided ground-mount project
  - Non-market benefits that are difficult to quantify
    - Use proxy values from research in other geographies and contexts
    - Several non-quantifiable benefits excluded from BCA
  - Includes mix of societal level and system level costs and benefits

BCA Results

- 2.5% Societal Discount Rate, 7.5 cent Adder

Case	Project Category	NPV Total Benefits ($/kW)	NPV Total Costs ($/kW)	Benefit-Cost Ratio
Low Benefits, Low Costs	Commercial	$607	$1,253	0.48
	Large	$419	$1,285	0.29
High Benefits, Low Costs	**Commercial**	**$2,223**	**$1,253**	**1.77**
	Large	$684	$1,285	0.53
Low Benefits, High Costs	Commercial	$607	$1,396	0.43
	Large	$419	$1,432	0.26
High Benefits, High Costs	**Commercial**	**$2,223**	**$1,396**	**1.59**
	Large	$684	$1,432	0.48

BCA Results: Sensitivity Analysis

Case	Project Category	Benefit-Cost Ratio		
		9.0 ¢ Adder	10.0 ¢ Adder	12.0 ¢ Adder
Low Benefits, Low Costs	Commercial	0.40	0.36	0.30
	Large	0.24	0.22	0.18
High Benefits, Low Costs	**Commercial**	**1.48**	**1.33**	**1.11**
	Large	0.44	0.40	0.33
Low Benefits, High Costs	Commercial	0.36	0.33	0.27
	Large	0.22	0.20	0.16
High Benefits, High Costs	**Commercial**	**1.33**	**1.19**	0.99
	Large	0.40	0.36	0.30

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Sustainable
Energy
Advantage, LLC

RI Renewable Energy Growth Program:
Carport Adder and Benefit-Cost Analysis, Revised November 2021

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Carport Adder Analysis

Sustainable Energy Advantage, LLC

REG Carports Selected, & 2021 Cost Data

Enrollment Period	Facility	Location	kWdc	Actual or Target COD	Incremental Carport Cost/kWdc
2020-1	Project 1			4/23/2021 (Actual)	
2020-1	Project 2			8/2022 (Est.)	
2020-2	Project 3			4/2023 (Est.)	
2021-1	Project 4			7/2023 (Est.)	$1,099.37 (Revised)
2021-1	Project 5			7/2023 (Est.)	$1,597.65 (Included)
2021-2	Project 6			Not Available	$1,503.50 (Added)

Text in red denotes data added or adjusted subsequent to September 23, 2021 stakeholder presentation.

Carport Cost Input Assumptions

Commercial Category

Cost Case	Incremental Cost Input	Notes
Low	$1,277 ~~$1,011~~	Publicly available[1] carport quote for 500 kW system
High	$1,400 ~~$1,277~~	Average of incremental costs from 2021 Open Enrollments 1 + 2.

Large Category

Cost Case	Incremental Cost Input	Notes
Low	$1,254 ~~$1,000~~	Publicly available[1] carport quote for 1,000 kW system
High	$1,254	Publicly available[1] carport quote for 1,000 kW system

Text in red denotes data added or adjusted subsequent to September 23, 2021 stakeholder presentation.

(1) https://www.solarelectricsupply.com/commercial-solar-systems/solar-carport

Carport Adder: Revenue Requirement Results

Required Adder Revenue, ¢/kWh

Size Category	Modeled Size (kW)	Low Cost/ High Production	Low Cost/ Low Production	High Cost/ High Production	High Cost/ Low Production
Commercial I	500	8.2	11.4	8.9	12.2
Commercial II	1,000	8.2	11.0	8.9	11.8
Large	5,000	8.3	11.7	8.3	10.7
Weighted Average		8.3	*10.8*	*8.4*	*11.0*
"Carport Adder Revenue Requirement" **(Rounded to nearest 0.25 ¢/kWh)**		**8.25**	**10.75**	**8.50**	**11.0**

Text in red denotes data added or adjusted subsequent to September 23, 2021 stakeholder presentation.

Benefit-Cost Analysis

Sustainable Energy Advantage, LLC

NPV of Quantified Benefits

- Total net present value of quantified benefits, assuming a societal discount rate of 2.5%

	Commercial ($/kW)		Large ($/kW)	
	Low Benefits	High Benefits	Low Benefits	High Benefits
Interconnection Cost Savings	$85	$106	$85	$106
Carbon Sequestration	$17	$237	$46	$105
Ecosystem Services	$2	$3	$2	$3
Avoided Property Value Loss	$824	$3,295	$183	$366
Total (Weighted by Avoided Project Type)	**$927**	**$3,641**	**$316**	**$581**

Text in red denotes data added or adjusted subsequent to September 23, 2021 stakeholder presentation.

BCA Results

- 2.5% Societal Discount Rate, 8.25 cent Adder
- **Bolded** results denote rows with Benefit-Cost Ratio greater than 1

Case	Project Category	NPV Total Benefits ($/kW)	NPV Total Costs ($/kW)	Benefit-Cost Ratio
Low Benefits, Low Costs	Commercial	$608	$1,378	0.44
	Large	$354	$1,414	0.25
High Benefits, Low Costs	**Commercial**	**$2,294**	**$1,378**	**1.66**
	Large	$660	$1,414	0.47
Low Benefits, High Costs	Commercial	$608	$1,536	0.40
	Large	$354	$1,575	0.22
High Benefits, High Costs	**Commercial**	**$2,294**	**$1,536**	**1.49**
	Large	$660	$1,575	0.42

Text in red denotes data added or adjusted subsequent to September 23, 2021 stakeholder presentation.

BCA Results: Sensitivity Analysis

Case	Project Category	Benefit-Cost Ratio		
		8.5 ¢ Adder	10.75 ¢ Adder	11.0 ¢ Adder
Low Benefits, Low Costs	Commercial	0.43	0.34	0.33
	Large	0.24	0.19	0.19
High Benefits, Low Costs	**Commercial**	**1.62**	**1.28**	**1.25**
	Large	0.45	0.36	0.35
Low Benefits, High Costs	Commercial	0.38	0.30	0.30
	Large	0.22	0.17	0.17
High Benefits, High Costs	**Commercial**	**1.45**	**1.15**	1.12
	Large	0.41	0.32	0.31

Text in red denotes data added or adjusted subsequent to September 23, 2021 stakeholder presentation.

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October 25, 2021

Distributed Generation Board
1 Capitol Hill
Providence, RI 02908

Re: NECEC Comments to DG Board - Carport Solar Adder

Dear Distributed Generation Board Members,

The Northeast Clean Energy Council ("NECEC") appreciates the opportunity to submit comments in support of the continuation of the Carport Solar Adder within the Renewable Energy Growth Program ("RE Growth"). As Rhode Island seeks to maximize the development of renewable resources, with a particular emphasis on the built environment, the Carport Adder is a valuable tool that has led to projects sited in beneficial areas. It should be continued at a level at which the benefits outweigh the costs.

NECEC is a clean energy business, policy, and innovation organization whose mission is to create a world-class clean energy hub in the Northeast, delivering global impact with economic, energy and environmental solutions. NECEC is the only organization in the Northeast that covers all of the clean energy market segments, representing the business perspectives of investors and clean energy companies across every stage of development. NECEC members span the broad spectrum of the clean energy industry, including clean transportation, energy efficiency, wind, solar, energy storage, microgrids, fuel cells, and advanced and "smart" technologies.

In its Benefit-Cost analysis, Sustainable Energy Advantage ("SEA") identified multiple benefits of the Carport Solar Adder including the opportunity to promote beneficial siting and alleviate land use challenges. In addition, unquantified benefits include avoided costs of snow clearing, and job-related benefits.

Any application of the Carport Adder that carries a Benefit-Cost Ratio greater than 1.0 should warrant a continuation for another year. As shown in the SEA analysis, there are several cases where the benefits outweigh the costs, including for high-benefits, low cost commercial projects at a 7.5 cent adder level. Additionally, it is likely that the Carport Adder would be cost-effective across all or most cases if the adder level were to be reduced. We urge the DG Board to recommend that National Grid propose a Carport Adder at a value by which the benefits are greater than the costs, even if it requires reducing the adder from historical levels. Such approval will allow continued market development of this segment or the solar industry.

Thank you for your consideration of these comments. Continuing the Carport Adder, even at a reduced value, will allow developers the opportunity to respond to the adder to develop these beneficially sited projects and, as such, we recommend continuing the Carport Adder.

Please contact me if you have any questions.

Sincerely,

Sean Burke
Policy Manager

Re: RI REG 2022 PY Program Development Announcements: Request for Comments Regarding Interconnection Proposal for 2023 Program Year and National Grid Determination Regarding Carport Solar Adder

To Whom It May Concern:

We are very confused by National Grid's determination regarding the Carport Solar Adder. Removal of the adder makes ~2MW of projects in our pipeline infeasible and they will likely be cancelled.

First, we don't understand why National Grid would propose removing the adder altogether. Why not set it at a rate that would provide an acceptable Benefit-Cost ratio and let the developers decide whether that incentive rate is enough to justify the development and construction of the system? The adder is not a carveout of MW in the program and it does not reduce the opportunity for non carport projects to participate in the program. The purpose of the adder is not to guess what developers will need to build a carport system, but instead to indicate the price at which the given system would meet the program requirements. The worst-case scenario is that no one would apply for the adder if it were insufficiently priced.

Second, the methodology used to conclude that the benefit does not justify the cost of an adder doesn't really make sense to us. The BCA ratios were calculated using a proposed adder of \$0.075/kWh when the adder offered during the pilot program has been \$0.06/kWh and \$0.05/kWh in the last 2 program years. Why not analyze the benefit-cost ratio using the adders offered to date? Alternatively, why not calculate the benefits of the program and base the proposed adder from that, rather than vice versa?

I used the tables on slide 18 and 19 of SEA's September 23, 2021 presentation to estimate program costs for scenarios where the adder is at \$0.05/kWh, \$0.04/kWh, and \$0.03/kWh. I also recreated the table at \$0.075/kWh to confirm it was consistent with the values in the presentation. I then calculated the BCA Ratio for the various scenarios, similar to the table presented on slide 18.

			3 cent adder		4 cent adder		5 cent adder		7.5 cent adder	
Case	Project Category	NPV Benefit	NPV Cost	BCA Ratio	NPV Cost	BCA Ratio	NPV Cost	BCA Ratio	NPV Cost	BCA Ratio
Low Benefits	Commercial	$607	$501	1.21	$668	0.91	$835	0.73	$1,253	0.48
Low Costs	Large	$419	$514	0.82	$685	0.61	$856	0.49	$1,285	0.33
High Benefits	Commercial	$2,223	$501	4.44	$668	3.33	$835	2.66	$1,253	1.77
Low Costs	Large	$684	$514	1.33	$685	1.00	$856	0.80	$1,285	0.53
Low Benefits	Commercial	$607	$558	1.09	$744	0.82	$930	0.65	$1,396	0.43
High Costs	Large	$419	$572	0.73	$763	0.55	$953	0.44	$1,432	0.29
High Benefits	Commercial	$2,223	$558	3.98	$744	2.99	$930	2.39	$1,396	1.59
High Costs	Large	$684	$572	1.20	$763	0.90	$953	0.72	$1,432	0.48
Average BCA: All sizes				1.85		1.39		1.11		0.74
Median BCA: All sizes				1.20		0.90		0.72		0.48
Average BCA: Commercial sizes				2.68		2.01		1.61		1.07
Median BCA: Commercial sizes				2.60		1.95		1.56		1.04
Average BCA: Large sizes				1.02		0.76		0.61		0.41
Median BCA: Large sizes				1.01		0.75		0.60		0.40

At a $0.03/kWh adder, the mean and median BCA ratio for all scenarios is greater than 1, which would meet the program's requirement for enacting a policy adder. Digging a bit further, when we segregate the commercial and large scale carports, we see that commercial scale carports show a mean and median BCA of greater than 1 in every scenario, not just in the $0.03/kWh scenario. To us, this suggests two paths forward: either

a) provide a single carport adder across all sizes which is low enough to provide a BCA ratio greater than 1; or
b) provide a commercial scale carport specific adder.

In either scenario, there is no justification for removing the adder completely because there is an adder rate greater than $0.00/kWh which provides a BCA ratio greater than 1. Between those two alternatives, the second seems to be the most beneficial to the program, as it would incentivize the system type which provides the highest benefit (commercial scale carports) rather than try to subsidize a neutral incentive (Large scale carports.) This conclusion is also supported by the fact that the mean benefits scenario (p.16 of SEA's presentation) for commercial scale carports is almost 4x the high benefits estimate for large scale carports ($2,312/kW vs $605/kW.)

In the first two years of the pilot program, 50% of available capacity has been enrolled, and potentially more pending the third enrollment of 2021. This is not evidence of an inadequate incentive, but rather is indicative of the amount of time it takes for developers to recognize and react to new opportunities, to find a suitable site(s) and to have an interconnection ready to submit into the program. As mentioned previously, we have 2MW of projects under development. There are many others underway as well.

The removal of this adder provides zero upside for the program. It does not free up MW's for other, more viable projects, but instead limits project opportunities in general. We believe it should be reconsidered for the 2022 program year as well as future years.

Thank you,
Sevag Khatchadourian
Oak Square Partners

Sustainable Energy Advantage, LLC

Rhode Island Renewable Energy Growth Program:

Research, Analysis, & Discussion in Support of First Draft 2022 Program Year Ceiling Price Recommendations

July 27, 2021

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Purpose

- To present stakeholder data responses, survey results, and supplemental research
- To *begin* the discussion that supports the development of Ceiling Price inputs and recommendations for the 2022 Renewable Energy Growth (REG) Program; and
- To develop Ceiling Price recommendations through an iterative, public process.

Draft 2022 Ceiling Prices, Categories and Modeling Parameters

Sustainable Energy Advantage, LLC

Proposed Ceiling Price Categories

2022 REG Program: Proposed Technology, Size & Tariff Length Parameters*			
Eligible Technology	**System Size for CP Development (DC)**	**Eligible System Size Range (DC)**	**Tariff Length**
Small Solar I	5.8 kW	≤ 15 kW	15 Years
Small Solar II	25 kW	15 to 25 kW	20 Years
Medium Solar	250 kW	26 to 250 kW	20 Years
Commercial Solar	500 kW	251 to 750 kW	20 Years
Commercial Solar – Community Remote DG (CRDG)	500 kW	251 to 750 kW	20 Years
Large Commercial Solar	900 kW	751 to 999 kW	20 Years
Large Commercial Solar – Community Remote DG (CRDG)	900 kW	751 to 999 kW	20 Years
Large Solar	4,500 kW	1 to 5 MW	20 Years
Large Solar - CRDG	4,500 kW	1 to 5 MW	20 Years
Wind	3,000 kW	0 to 5 MW	20 Years
Anaerobic Digestion	750 kW	≤ 5 MW	20 Years
Hydropower	500 kW	≤ 5 MW	20 Years

***These Renewable Energy Classes may change as a result of the proposals described in** REG 2022 Program Year Ceiling Prices - Initial Options Regarding Solar Performance Assumptions and Solar Class Subdivisions for Stakeholder Comment

Summary Results (1): Solar (cents/kWh)

Technology	Tariff Term (Years)	Size Range kW (Modeled Size kW)	2021 Approved CP	2022 1st Draft Proposed CP (w/Year-on-Year (YoY) Solar Capital Cost Adjustment)	2022 1st Draft Proposed CP (w/o YoY Solar Capital Cost Adjustment)**
Small Solar I	15	1-15 (5.8)	28.75	**26.85 (-7%)**	**27.85 (-3%)**
Small Solar II	20	15.01-25 (25)	24.35	**24.25 (-0.4%)**	**25.05 (3%)**
Medium Solar	20	26-250 (250)	21.65	**21.35 (-1%)**	**22.05 (2%)**
Commercial Solar	20	251-750 (500)	18.55	**17.55 (-5%)**	**18.15 (-2%)**
Commercial Solar-CRDG	20	251-750 (500)	21.33	**20.18* (-5%)**	**20.87 (-2%)**
Commercial Solar	20	751-999 (900)	15.25	**14.55 (-5%)**	**15.05 (-1%)**
Commercial Solar-CRDG	20	751-999 (900)	17.54	**16.73* (-5%)**	**17.31 (-1%)**
Large Solar	20	1,000-5,000 (4,500)	11.35	**9.95 (-12%)**	**10.35 (-9%)**
Large Solar-CRDG	20	1,000-5,000 (4,500)	13.05	**11.44* (-12%)**	**11.90 (-9%)**

*This is the maximum CRDG Ceiling Price allowed by law. The calculated 2022 values are (depending on whether the Solar YoY capital cost adjustment is included) between 20.55 and 21.15 for Commercial CRDG 251-750, 17.55 and 18.05 for Commercial CRDG 751-999 and 12.85 and 13.25 for Large CRDG. Note, however, that this CP would allow cost-competitive projects (bidding below the CP) access to > a 15% premium compared to actual project costs.

**The values in this column reflect what the prices would be if the prices were to not include the typical year-on-year (YoY) cost reduction factor for Solar capital costs, considering the atypical inflationary pressures on key aspects of solar "hard" costs currently being experienced in the market. Given that SEA may recommend prices that do not use this factor, we have chosen to include this high-end estimate to show a range of the pricing values currently under consideration (excluding the potential impact of the capacity factor and degradation assumptions under consideration in REG 2022 Program Year Ceiling Prices - Initial Options Regarding Solar Performance Assumptions and Solar Class Subdivisions for Stakeholder Comment

Summary Results (2): Wind, Hydro & AD (cents/kWh)

Technology	Tariff Term (Years)	Size Range kW (Modeled Size kW)	2021 Approved CP	2021 1st Draft Proposed CP
Wind	20	0-5,000 (3,000)	18.75	**20.75 (11%)***
Wind - CRDG	20	0-5,000 (3,000)	21.05	**22.85 (9%)***
Hydroelectric	20	1-5,000 (500)	27.35	**27.75 (2%)***
Anaerobic Digestion	20	1-5,000 (750)	15.35	**20.85 (32%)***

*Increases in Ceiling Prices for non-Solar technologies driven mainly by the expiration of the PTC and resulting changes in financing assumptions.

Overview of Key Stakeholder Feedback and Modeling Implications

Sustainable Energy Advantage, LLC

Summary of Data/Survey Response

Ceiling Price Category	# of Data Points Received (Data Request or Survey)
Solar	15
Non-Solar	1
Both Solar and Non-Solar	1
TOTAL	17

Installed & Interconnection Cost Assumptions & Methodology

- MA SMART program does not make total cost available until projects are complete → cost data only available for small solar
- Data for residential projects available from CT residential incentive program and EnergySage average pricing data from quotes accepted by Northeast customers
- RI Renewable Energy Fund and REG Open Enrollment Results
  - REG Open Enrollment results contained some values for total project costs that do not align with bid prices; Small Solar reported costs significantly higher than other sources
  - Therefore, robust data available from RI and other Northeast states available for small solar, but data is very limited for Medium, Commercial, and Large Solar classes
- **SEA plans to work with stakeholders (including OER, the DPUC and National Grid, and other interested parties) to develop bid submittal rules for the 2022 PY requiring documentation of project upfront capital costs (and non-capital operating costs)** to ensure unit cost estimates clearly align with bid values
- **Modeling Implication (M.I.):**
  - **Small Solar I and II use similar approach to previous years, based upon NY, MA, CT data from incentive programs and Energy Sage quotes, plus REF data**
  - **Medium, commercial, large solar rely upon NY data, REG Open Enrollment Data, and data from the Lawrence Berkeley National Laboratory (LBNL). For large solar, use 75th percentile of NY data to reflect lower costs in upstate NY regions**

Assumption of Year-on-Year Cost Declines

- **Stakeholder Feedback:** Broad Solar stakeholder consensus indicates substantial upward pressure on costs (especially on hardware) following easing of impact of COVID-19 pandemic on (parts of the) global economy, as well as following Biden Administration action against Xinjiang-based polysilicon manufacturing
  - Many have specifically indicated that these factors should obviate the need for any kind of year-on-year cost decline factor
- **Consulting Team Response:** SEA is aware of these dynamics and agrees that these factors warrant a special response vis-à-vis the Ceiling Price inputs. Stakeholders have also indicated that inflationary pressures (especially steel) are also affecting project economics. SEA is also aware (despite the relative lack of response to the Data Request and Survey) that this is also an issue for Non-Solar
- **Multiple M.I.s:**
  - **During the 2022 process, SEA will report its Solar Ceiling Prices <u>both with and without the typical year-on-year cost decline factor</u> in order to signal the pending uncertainty associated with the atypical price increases seen during 2021, and further signal that forward-looking cost declines may be abandoned for 2022 as circumstances (and evidence) warrant.**
  - **SEA also plans to investigate the matter of current inflationary dynamics for all renewable energy projects further prior to settling on a final approach, and furthermore may take steps ranging from:**
    - **Removing the year-on-year Solar factor entirely**
    - **Adding exogenous inputs to simulate the effect of higher project costs for both Solar and Non-Solar projects; and/or**
    - **Utilizing a hybrid approach (e.g. assuming a decline for certain aspects of Solar and Non-Solar project costs, but an increase for others)**

Interconnection Cost Changes for Projects >25 kW

- Treatment of Interconnection Costs
  - Federal Investment Tax Credit (ITC) for solar excludes interconnection equipment & upgrades from ITC eligibility
  - However, state cost databases and 1st Open Enrollment data assumed to include IC costs
- **M.I.: As in prior years, 2020-2021 RI average interconnection costs assumed deducted from basis for 26% ITC (thereby increasing Ceiling Prices proportionately to the amounts deducted)**
- Analysis of 2020 and 2021 Data
  - Similar to 2020, first half of 2021 had an insufficient number of projects interconnecting to base analysis off only 2021 data
  - Therefore (as in 2021 CP process), the team used data from 2020-2021 YTD to ensure robust results within size bins (esp. for Commercial as shown in the table)

Size Bin	2020 Sample Size	2021 Sample Size	Average non-zero IC cost for 2020 and 2021*
1 MW - 5 MW	18	5	$173
250 kW - 1 MW	4	1	$114
25 kW - 250 kW	17	7	$187
<25 kW	6	0	$123**

Notes: *Includes an 85% de-rate on costs, as applied by National Grid
**For <25 kW, we include projects with no reported IC costs

Interconnection Cost Changes for Projects >25 kW (Cont'd)

- Overall, IC cost trends are in line with trends identified during the 2021 PY analysis, with increasing IC costs for Large and Medium Solar projects and falling IC costs for Commercial Solar projects.

RI Average IC Cost per kW_{DC}	2020 CP ($/kW)	2021 CP ($/kW)	% Change (2020 PY to 2021 PY)	2022 1st Draft ($/kW)	% Change (2021 PY to 1st Draft 2022 PY)
Large Solar (1-5 MW)	$134	$147	10%	**$173**	18%
Commercial Solar (250 kW - 1 MW)	$151	$133	-12%	**$114**	-14%
Medium Solar (25-250 kW)	$49	$118	141%	**$187**	58%
Wind (0-5 MW)	$295*	$295*	0%	**$295***	0%
Hydro (0-5 MW)	$500*	$500*	0%	**$500***	0%
Anaerobic Digestion (AD, 0-5 MW)	$150*	$150*	0%	**$150***	0%

*Notes: *National Grid appears to have received no interconnection applications for the non-solar technologies listed above during 2020 or 2021. As such, these inputs have remained unchanged from prior years.*

Small Solar I/II – Financing Assumptions

- SEA has received feedback from long-time market participants that REG Small Solar I is struggling to compete with net metering
  - One such participant noted that they were only able to complete a single Small Solar I system in 2020 due to these challenges
- Though not all participants have struggled to sell REG projects, these comments are consistent with reduced activity in the Small Solar market segments in recent years
  - Specifically, stakeholders have argued that the assumed Target After-Tax Equity IRR of 5.2% is too low to drive interest in the market segment
- Though SEA shares these concerns, only two Small Solar participants responded to the survey.
  - As a result, we currently have insufficient data to substantiate revisions to these inputs without greater response ➔ **Please provide SEA with any data that may be pertinent to these issues**
- **M.I.: Increased equity shares to ensure proper debt service coverage and increased target IRR to 7% (given reduced market activity), but no other change for Draft 1. However, SEA will re-assess based on available data if provided**

Small Solar I/II – Proxy Size & Interconnection

- Small Solar I and II modeled size
  - **Stakeholder Feedback:** Stakeholders have previously expressed support for modeling Small Solar I based on real-world capacity data
  - **M.I.: Model Small Solar I as 5.8 kW (previously 5 kW), based on the average nameplate capacity enrolled in REG to date, but continue to model Small Solar II as 25 kW.**
- Small Solar II Interconnection Issues
  - In recent years, SEA has been made anecdotally aware of a number of complex (and costly) <=25 kW solar project interconnections
  - The average interconnection cost for the six Small Solar II (15-25 kW) projects in National Grid's database (including projects in which the cost of system modifications is $0) is now **$143/kW** (which is down from **over $200/kW** over 2019 through H1 2020)
  - As a reminder, interconnection costs do not increase installed costs (given that the databases we utilize specify interconnection as part of installed costs), <u>but do affect the degree of project costs excluded from ITC eligibility</u>
  - **M.I.: No immediate change to Small Solar II pricing/ITC treatment to account for these six interconnections, but SEA plans to request more information from National Grid about the nature of the interconnections in question to determine if such "outlier" cases should be (somehow) accounted for in setting the Small Solar II Ceiling Price.**

Incremental CRDG Capital & Operating Costs

- Incremental costs for Community Remote Distributed Generation (CRDG) projects are comprised specifically of
  - A capital cost component (in $/kW, the upfront cost of customer acquisition); and
  - An OpEx component (in $/kW-yr, the ongoing cost of customer maintenance/care)
- For several years, SEA has maintained an assumption of **$150/kW for customer acquisition, and $25/kW-yr for customer maintenance/care**
  - Until recently, most market participants have indicated that these costs are very "sticky" and difficult to reduce
- However, several stakeholders have validated our new estimate (derived from a separate market participant survey) of **$100/kW and $22/kW-yr** is accurate, while other CRDG participants have indicated that the OpEx component could go **as low as $12/kW-yr**
- **M.I.: Adopt $100/kW and $22/kW-yr figure for CapEx and OpEx, but plan to request more data from CRDG participants to determine whether even lower figures may be justifiable**

Solar Project Operating Cost and Performance Assumptions – Fixed O&M

- **Large Solar:** One stakeholder indicated that Large Solar prices are closer to $7-$8/kW-yr. This assumption was largely verified by recent research by Lawrence Berkeley National Laboratory (LBNL), which found a range for utility-scale projects of approximately $5-$8/kW-yr
- **Small Solar I & II:** Recent research by the National Renewable Energy Laboratory (NREL) found that O&M prices for residential and commercial-scale systems were $29/kW-yr and $19/kW-yr, respectively.
- **Multiple M.I.s:**
  - **Reduce Large Solar fixed O&M from $12/kW-yr to $8/kW-yr;**
  - **Reduce Small Solar I fixed O&M from $35/kW-yr to $29/kW-yr;**
  - **Reduce Small Solar II fixed O&M from $35/kW-yr to $24/kW-yr (the average of $29/kW-yr and $19/kW-yr found in the NREL analysis); and**
  - **Leave all other fixed O&M inputs unchanged.**

Post-Tariff Project Revenue Assumptions

- In previous REG Ceiling Price analysis, SEA had assumed that facilities participating in REG could only get energy and RECs post-tariff
- It has since come to our attention that such facilities are eligible to participate in net metering post tariff (see § 39-26.6-23)
  - **M.I.: Moving forward, we propose to assume that post-tariff energy revenue for all technologies will be based on Net Metering rates (or a comparable successor policy) as opposed to wholesale rates, with a 40% discount applied to account for future revenue uncertainty**
    - **Generally, SEA believes that the state will be incentivized (based on its pursuit of a 100% RE grid) to preserve its existing clean generation**
- To forecast net metering rates, SEA utilizes an internal forecast of National Grid's C-06 rate (applicable to small commercial customers), in which:
  - Wire charges are forecasted based on planned T&D investments combined with long-term expectations; and
  - Generation charges are forecasted as a function of projected energy and capacity price
  - **M.I.: Assume post-tariff energy revenue starts at 11.6 cents/kWh for C-06 (commercial) and 12.9 cents/kWh for A-16 (residential), with a compound annual growth rate (CAGR) of 2.24% for both**

Post-Tariff Project Revenue Assumptions (Cont'd)

	2021 CP Wholesale Energy and Capacity (¢/kWh)	2022 1st Draft CP Resi. Net Metering w/ 40% discount (¢/kWh)	2022 1st Draft CP Comm. Net Metering w/ 40% discount (¢/kWh)
2037	4.62	12.92	11.62
2038	4.73	13.21	11.88
2039	4.85	13.50	12.14
2040	5.00	13.79	12.40
2041	5.15	14.08	12.66
2042	5.27	14.37	12.92
2043	5.39	14.66	13.18
2044	5.52	14.94	13.44
2045	5.65	15.23	13.70
2046	5.78	15.52	13.96
2047	5.92	15.81	14.22
2048	6.06	16.10	14.48
2049	6.21	16.39	14.74
2050	6.37	16.68	15.00

Project Operating Cost and Performance Assumptions (Cont'd)

- In recent years, evidence has been mounting that developers/projects sponsors have been assuming longer useful lives for solar and wind projects
  - However, given the efforts related to the development of potential Public Policy Adders, SEA chose to defer consideration of this issue to the 2022 Ceiling Price development cycle
- In addition, consultants to the Division of Public Utilities and Carriers (DPUC) noted that previous post-tariff revenue assumptions based on wholesale energy and REC monetization did not cover ongoing operating expenses during post-tariff period
  - As a result, for the 2021 Ceiling Prices, SEA curtailed the post-tariff revenue period to 0 years.
- Importantly, the new post-tariff revenue assumptions (discussed on the prior slide) **enable profitable operation of all technologies and sizes beyond their tariff term**
- **Multiple M.I.s:**
  - **Re-establish the assumed useful life for all Solar and Hydro projects to 25 years and 30 years, respectively, as last assumed in the 2020 CPs;**
  - **Assume a 30-year useful life for wind turbines (based on extensive 2019 LBNL survey and analysis)**
  - **Consider extending assumptions for some or all Solar renewable energy classes to 30 years (or possibly longer) as a component of the 2nd Draft CP analysis**

Project Operating Cost and Performance Assumptions – Insurance and Other Non-Solar Assumptions

- Insurance (% of Project Cost/yr)
  - Several participants noted large increases during the past year, but did not provide verified quotes/other information to substantiate
  - A participant last year did provide quotes, but values were sufficiently different from prior value to require investigation
  - According to one insurance industry participant, number of insurance policies requiring payouts (i.e. due to disasters and other events) in the last few years have increased sharply
  - **M.I.: No change 1st draft, but SEA will request more information on insurance costs in a follow-up survey**
- Non-Solar Cost and Performance Assumptions
  - No significant changes (at least with documentation) proposed, and limited competitive activity observed in any segments (Wind/Hydro/AD)
  - **M.I.: Keep same costs Wind/Hydro/AD until Non-Solar participants can provide documented evidence of changes to inputs (follow-up expected by the time of 2nd Draft Ceiling Prices)**

Financing Assumptions for >25 kW (ITC, Debt Term and Share, Equity Share)

- Debt Term (Years)
  - While some market participants can get longer than 15 years (for Solar) and 20 years (Hydro) from their lenders, it remains unlikely that this will be the norm, even in a fixed-price tariff program such as REG
    - **M.I.: Maintain 15-year debt term for Solar and 20-year for Hydro**
- % Equity Share of Sponsor & Tax Equity
  - **Solar:** Project sponsors/developers will continue to seek as much tax equity as possible given the lower relative cost of tax equity, despite contractions and uncertainties in the supply of tax equity due to COVID-19. More than one developer continued to note ongoing tax equity constraints
    - **M.I.: Share of tax equity in equity stack to remain at 75% for Solar projects (given 2-year extension of 26% ITC value)**
  - **Wind, Hydro & AD:** Participants not assumed to be able to access tax equity (given expected expiration of PTC & ILoPTC), but are expected to still access tax benefits via accelerated depreciation
    - **Multiple M.I.s**
      - **Sponsor equity for Wind and AD increased from 25% to 60% (given expected expiration of ITC in lieu of PTC December 31, 2021), and tax equity reduced from 75% to 40% (rather than 0%, to reflect tax benefits of accelerated depreciation)**
      - **Hydro Sponsor equity set at 80% (previously 100%), and tax equity increased to 20% (rather than 0%, to reflect tax benefits of accelerated depreciation (in the case of Hydro, to reflect 7-year (rather than 5-year) MACRS**

Financing Assumptions for >25 kW (Interest Rates on Term Debt)

- Overall Outlook:
  - Relative to 2020, debt financiers report premiums above LIBOR unchanged for RE "vanilla" loans
  - 3-month LIBOR has stayed mainly flat (with a slight decrease over 12 months) but swap values have risen with yields on US Treasuries LIBOR, resulting in a slight increase in interest rates on 15- and 20-year term debt
- 12-month change in LIBOR 90-day rate
  - Declined from 0.27% to 0.14% (as of 7/5, **-13 bps**)
- LIBOR Swap/US Treasury Yield Value
  - Lenders typically "swap" LIBOR to lock in its value over the life of a substantial loan (e.g. 15 years for solar, wind, and AD vs. 20 years for hydro)
  - 10-year swap value +**143 bps** on 7/5
  - Based on this, tentative assumption of **+171 bps** for a 15-year swap (representing the average of 10-year and 20-year Treasury yields on 7/5 as proxy for 15-year LIBOR swap rate)
  - 20-year Treasury yield (on 7/5): **+198 bps**
  - Previous 15-year swap assumption (2021 CPs, for non-Hydro projects): **+100 bps**
  - ***15-year swap premium over 2021 CP assumption (for non-Hydro): +70 bps***
  - ***20-year swap premium over 2021 CP assumption (for Hydro): +100 bps***
  - ***LESS: -13 bps (12-month 90-day LIBOR change)***
- **M.I.: Net increase = ~+60 bps for non-Hydro, ~+90 bps for Hydro**

Financing Assumptions for >25 kW (ITC, Debt Term and Share, Equity Share)

- ITC/ILoPTC Value
  - **Solar (ITC):** ITC value will remain at 26% per current law until December 31, 2022
    - **M.I.: Assume 26% ITC value for Solar**
  - **Wind/Hydro/AD (ITC in Lieu of the PTC (ILoPTC)):** PTC set to expire per current law at end of 2021
    - **M.I.: Assume no federal tax credits available to Wind/Hydro/AD (with subsequent ramifications for debt/equity shares)**
- Debt (% of Hard Costs)
  - Modeling during 2021 PY development process suggested maintaining current debt/equity ratios (rather than assuming debt share can increase to compensate for declining tax equity shares) necessary to ensuring appropriate debt service coverage
    - **M.I.: Debt shares held constant from final 2021 levels, except those in which coverage levels require a decrease in share (or allow an increase in share)**
- Depreciation
  - Developers continue to indicate 5-year MACRS is standard due to tax equity investors' desire to preserve limited tax capacity
  - **Solar M.I.: Continue to assume 5-year MACRS utilized**
  - **Wind/Hydro/AD M.I.: Wind once again assumed to be a 50/50 split of MACRS and 100% bonus depreciation (per developer feedback). Hydro and AD still assumed unable to elect 100% bonus depreciation due to long duration of construction**

Financing Assumptions for >25 kW (All Other Assumptions)

- Sponsor Equity IRRs:
  - With the substantial easing of the COVID-19 pandemic (and concurrent increase in appetite for new investment in favored asset classes such as renewable energy), we assume that equity returns will return to their longer-term averages
  - However, stakeholders have indicated that despite the increase in economic activity following the general re-opening of the economy, that said returns/“hurdle rates” have not moved quickly back in the direction of long-term averages
  - Given the REG program’s heavy reliance on host ownership for projects under 1 MW, we believe the stakeholders’ caution is warranted
  - **M.I.: Reduce sponsor equity IRRs by 50 bps (0.5%) across the board but continue to observe the economic situation for signals that larger reductions may be reasonable.**

Restated Financing Modeling Implications (Relative to Initial 2022 1st Draft PPT)

- Tax Equity IRRs
  - There appear to be few discernible changes in demand for tax equity capital, and no change in policy since the Consolidated Appropriations Act of 2021
  - However, SEA has determined there is no clear reason tax equity terms for Solar and non-Solar projects should be different by resource (as was assumed in 2021 Ceiling Prices)
  - **M.I.: Non-Solar IRRs increased from 9.0% to 9.5%, but IRRs for Solar projects unchanged at 9.5%, but may change if infrastructure bill with significant clean energy tax provisions enacted**
- Accounting for Impact of Property Values on "Tangible Taxes"
  - Some stakeholders have indicated (and provided supporting data to substantiate) that solar and wind projects in certain municipalities have been subject to local "tangible taxes" that go beyond those typically accounted for in the Ceiling Prices
  - SEA has verified that it has accounted for the $5/kW property tax value across resources, but has come to understand that some municipalities (but not others) have also increased the valuation of the property as a result of the installation of a renewable energy project
  - **M.I.: No change for the current draft, but SEA will investigate the frequency of changes to underlying property value for 2nd Draft prices**

NOTE: No changes to proposed CPs required based on the above

Summary: Financing Assumptions (Small Solar)

	Small I (1-15 kW)		Small II (15-25 kW)	
	2021 Final	***2022 Proposed***	***2021 Final***	***2022 Proposed***
Federal Investment Tax Credit (%)	26%	**26%**	26%	**26%**
% Debt	71%	**60%**	60%	**50%**
Debt Term (years)	13	**13**	10	**10**
Interest Rate on Term Debt	6.3%	**6.3%**	7.0%	**7.0%**
Lender's Fee (% of total borrowing)	4.25%	**4.25%**	2.3%	**2.3%**
Target After-Tax Equity IRR	5.2%	**7%**	13.0%	**12.5%**

Summary: Financing Assumptions (Solar >25 kW)

	Medium (25-250 kW)		Comm'l & Comm'l CRDG (251-999 kW)		Large & Large CRDG (1 MW-5 MW)	
Assumption Set	***2021 Final***	***2022 1st Draft***	***2021 Final***	***2022 1st Draft***	***2021 Final***	***2022 1st Draft***
Federal Investment Tax Credit (%)	26%	**26%**	26%	**26%**	26%	**26%**
% Debt	55%	**55%**	55%	**55%**	55%	**53%**
Debt Term (years)	15	**15**	15	**15**	15	**15**
Interest Rate on Term Debt	6.0%	**6.6%**	5.25%	**5.85%**	5.25%	**5.85%**
Lender's Fee (% of total borrowing)	1.0%	**1.0%**	1.0%	**1.0%**	2.0%	**2.0%**
% Equity Share of Sponsor Equity	25%	**25%**	25%	**25%**	25%	**25%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	13.5%	**13.0%**	12.5%	**12.0%**	11.5%	**11.0%**
% Equity Share of Tax Equity	75%	**75%**	75%	**75%**	75%	**75%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	**9.5%**	9.5%	**9.5%**	9.5%	**9.5%**
Depreciation Approach	5-Year MACRS	**5-Year MACRS**	5-Year MACRS	**5-Year MACRS**	5-Year MACRS	**5-Year MACRS**

Summary: Financing Assumptions (Non-Solar)

	Wind & Wind CRDG		Hydroelectric		Anaerobic Digestion	
Assumption Set	***2021 Final***	***2022 1st Draft***	***2021 Final***	***2022 1st Draft***	***2021 Final***	***2022 1st Draft***
Federal Investment Tax Credit	18%	**0% (Expiring 1/1/2022)**	0% (Available but not Monetizable)	**0% (Expiring 1/1/2022)**	30%	**None (Expiring 1/1/2021)**
% Debt	60%	**60%**	70%	**70%**	45%	**45%**
Debt Term (years)	15	**15**	20	**20**	15	**15**
Interest Rate on Term Debt	6.0%	**6.6%**	6.25%	**7.15%**	6.25%	**6.85%**
Lender's Fee (% of total borrowing)	1.0%	**1.0%**	1.88%	**1.88%**	1.5%	**1.5%**
% Equity Share of Sponsor Equity	25%	**60%**	100%	**80%**	20%	**60%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	12.5%	**12.0%**	12.5%	**12.0%**	12.5%	**12.0%**
% Equity Share of Tax Equity	75%	**40%**	0%	**20%**	0%	**40%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.0%	**9.5%**	9.0%	**9.5%**	9.0%	**9.5%**
Depreciation	5-Year MACRS	**Average of 100% bonus and 5-Year MACRS**	7-year MACRS	**7-year MACRS**	5-year MACRS	**5-year MACRS**

Summary: Cost & Production Assumptions (Solar)

	Small I	Small II	Medium	Comm'l (251-750)	Comm'l CRDG (251-750)	Comm'l (751-999)	Comm'l CRDG (751-999)	Large	Large CRDG
Nameplate Capacity (kW)	5.8 [5]	25	250	500	500	900	900	4,500	4,500
Capacity Factor	14.0%	14.0%	14.5%	14.6%	14.6%	14.6%	14.6%	15.10%	15.10%
Annual Degradation	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Total Cost w/YoY Solar Capital Cost Adjustment^ ($/kW)	$3,195 [$3,146]	$2,935 [$2,883]	$2,211 [$2,332]	$1,936 [$2,097]	$2,036* [$2,247*]	$1,780 [$1,869]	$1,880* [$2,019*]	$1,313 [$1,492]	$1,413* [$1,642*]
Total Cost w/o YoY Solar Capital Cost Adjustment^ ($/kW)	$3,311 [$3,146]	$3,042 [$2,883]	$2,315 [$2,332]	$2,027 [$2,097]	$2,127* [$2,247*]	$1,863 [$1,869]	$1,963* [$2,019*]	$1,375 [$1,492]	$1,475* [$1,642*]
Fixed O&M ($/kW-yr)	$29 [$35]	$24 [$35]	$14.57	$12.03	$34.03 [$37.03]	$12.03	$34.03 [$37.03]	$12.03	$34.03 [$37.03]
O&M Escalation Factor	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation Factor	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.27%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%
Project Management ($/yr)	$0	$0	$3,000	$4,000	$4,000	$4,000	$4,000	$12,000	$12,000
Site Lease ($/yr)	$0	$0	$12,000	$20,000	$20,000	$20,000	$20,000	$50,000	$50,000

Values in [Brackets] represent 2021 ceiling price inputs
* Reflects installed cost of non-CRDG project from same category, plus estimated cost of customer acquisition ($100/kW, previously $150/kW)
^ Total cost includes interconnection cost

Summary: Cost & Production Assumptions
Wind, Hydro, and AD

	Wind	Large Wind - CRDG	Hydroelectric	Anaerobic Digestion
Nameplate Capacity (kW)	3,000	3,000	500	725
Capacity Factor	21.00%	21.00%	55.00%	92%[1]
Annual Degradation	0.5%	0.5%	0.0%	0.0%
Total Cost ($/kW)	$2,820	$2,970	$9,931	$10,150
Fixed O&M ($/kW-yr)	$26.50	$48.50 [$51.50]	$2.00	$600
O&M Inflation	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.20%	0.20%	2.7%	1.0%
Project Management ($/yr)	$18,000	$18,000	$3,000	$75,000
Site Lease ($/yr)	$162,000	$162,000	$8,750	$35,000

1. *Note: For Anaerobic Digestion we use an Availability Factor*

Sustainable Energy Advantage, LLC

2022 PY RI Renewable Energy Growth Ceiling Price Development:

Overview of Potential Options Related to Solar Performance Assumptions and Solar Renewable Energy Class Subdivisions

July 27, 2021

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Proposed Updates/Adjustments to Solar Performance Assumptions (REG 2022 PY)

Sustainable Energy Advantage

Background/Results of National Grid Consideration of Adjustments to Capacity Factor Assumptions

- In response to requests made by Small Solar market participants, National Grid undertook an analysis to determine if the capacity factor the company utilized to size REG and net metering projects to load (as required by state law) represents real-world operating conditions
- Prior to National Grid's analysis, this Year 1 capacity factor (which matched the one utilized in the formula for calculating PV sizing to load) was 14.0%
- National Grid found that:
  - The 14% capacity factor estimate (and those generated by PVWatts, a public tool maintained by the National Renewable Energy Laboratory (NREL)) appear to overestimate real-world production
  - The observed mean capacity factor was 8.7% lower, **resulting in an estimate of 12.8%**.
- Following the analysis (and a presentation to the DG Board), National Grid changed its sizing guidelines to a table of values based on varying tilts and azimuths (but centered on the aforementioned 12.8% value)

SEA MA-SMS Degradation Analysis – Data and Overview

- SEA operates the Massachusetts Solar Market Study (MA-SMS), in which the company forecasts SREC I and SREC II prices
- A significant input to this analysis is an understanding of weather-normalized solar production originating from projects in Massachusetts
- In response to a public records request, SEA has received an anonymized data set with unique IDs from DOER containing the *monthly* production data from over 90,000 solar facilities in MA from 2010-2019
- SEA has utilized these data, in combination with irradiance data from NASA, to assess the average weather-normalized solar production degradation in MA
- *Note: This analysis assesses the "all in" degradation rate, which is inclusive of O&M issues*

SEA MA-SMS Degradation Analysis – Methods

- **Step One: Identification of projects with valid data** (i.e., once production has begun the project does not go offline). Projects with valid data are separated into cohorts based on their first year of production (from 2012 to 2016) and size as follows:
  - 0-25 kW
  - 25-1000 kW
  - 1000+ kW
- **Step Two: Indexing yearly production *in non-snowy months (March-November)* of all projects** in each cohort to the average production of all projects in the given cohort across all years
  - The first year of production is excluded to prevent bias from mid-year CODs

SEA MA-SMS Degradation Analysis – Methods

- **Step Three: Dividing each year's indexed production by an irradiance index** (based on the irradiance of all non-winter months) to produce a production curve normalized for weather
- **Step Four: Averaging of year-to-year change in each cohort's production curve** normalized for weather (to derive the average degradation rate for each cohort)
- **Step Five: Derivation of weighted-average degradation rate across all temporal cohorts in the same size bin** to arrive at a final estimate for that size bin
  - Each cohort's average is weighted based on the number of system-years in the cohort
  - *Example: The >1 MW cohort with production starting in 2012 had 7 years of data and 25 systems ➔ 175 system-years*

Degradation Analysis – Results

- This process results in the following average annual degradation rates per size bin:

Size Bin	Applicable REG Solar Renewable Energy Classes by Size Bin	Average Annual Degradation (Based on monthly data, excluding snowy months)
>1 MW	Large Solar, Large Solar CRDG	-0.56%
25 kW-1 MW	Medium Solar, Commercial Solar, Commercial Solar CRDG	-1.08%
<=25 kW	Small Solar I, Small Solar II	-1.51%

Comparison to Recent Public Analyses

- Recent meta-analysis undertaken by kWh Analytics (a well-respected data analytics firm) found (similarly to SEA) degradation for smaller systems to be more pronounced than for larger projects
- Results indicate that, at minimum, estimates in excess of 1% appear to better represent (if somewhat underestimate) degradation rates for small- to medium-scale DG projects

Table 1. Degradation Research (2016 - 2020)

Authors & Date	Analysis Type	Site Type	Measurement Point*	Yearly Degradation
Current Industry Assumption				
NREL (Jordan et al.) 2016	Meta-analysis (200 studies)	C&I, Resi, and Utility	25% System 75% Module	Median: -0.5%
Latest Research				
NREL (Deceglie et al.) 2018	RdTools	C&I and Resi	System	Median: -1.0% non-resi -1.2% resi
LBL (Bolinger et al.) 2020	Fixed effects regression	Utility	System	Mean: -1.1% Sigma: +/-0.2%
NREL (Deline et al.) 2020	RdTools	C&I and Utility	Inverter	Median: -0.72%
kWh Analytics 2021	RdTools	C&I, Resi, and Utility	System	Median: -1.09% resi -0.80% non-resi

Source: kWh Analytics' 2021 Solar Risk Assessment

Key Options for Determining Capacity Factor & Degradation Approach (Solar <=25 kW_{DC})

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%**
Assumption of NGRID-derived capacity factor from RI-based analysis (described in other slides)	**12.8%**

Annual Degradation Rate (%/yr)	
Approach Summary	*Assumed Value*
Annual degradation rate from 2021 CPs left unchanged	**0.5%/yr**
Two-year phase-in of 1.5% degradation rate (0.5% in 2022, rest in 2023)	**1.0%/yr**
Full assumption of 1.5% degradation rate	**1.5%/yr**

SELECTED APPROACH FOR <=25 kW WOULD SELECT ONE FROM EACH SET OF OPTIONS

Key Options for Degradation Approach (Solar >25 kW_{DC})

>25 kW-1 MW (Medium Solar, Commercial Solar, Commercial Solar CRDG)	
Approach Summary	*Assumed Value (%/yr)*
No change in current annual degradation rate assumption	**0.5%/yr**
Average of current assumed degradation and observed field degradation (1/2 in 2022, rest in 2023)	**0.8%/yr**
Observed field degradation	**1.1%/yr**

>1 MW (Large Solar, Large Solar CRDG)	
Approach Summary	*Assumed Value (%/yr)*
No change in current annual degradation rate assumption	**0.5%/yr**
Observed field degradation	**0.6%/yr**

SELECTED APPROACH FOR >25 kW WOULD SELECT ONE FROM EACH SET OF OPTIONS

Request for Comments

- **No later than August 20, 2021, SEA requests <u>written</u> comment regarding:**
  - The proposed Year 1 Capacity Factor and Annual Degradation Rate options for REG Solar projects <=25 kW on p. 10 **(by noting which Year 1 Capacity Factor and Annual Degradation Rate option you/your firm would favor, and why)**
  - The proposed Annual Degradation Rate options for REG Solar projects >25 kW on p. 11 **(by noting which option(s) for the various size categories indicated (>25 kW-999 kW and >1 MW) you/your firm would favor, and why)**
- **Please send all written comments in the form of a PDF (on company or other official letterhead, if possible)** to me (Jim Kennerly, jkennerly@seadvantage.com), Jason Gifford (jgifford@seadvantage.com) and Toby Armstrong (tarmstrong@seadvantage.com) at SEA, as well as to Chris Kearns (Christopher.Kearns@energy.ri.gov) and Shauna Beland (Shauna.Beland@energy.ri.gov) at OER.

Considerations for Solar Renewable Energy Class Subdivision

Sustainable Energy Advantage

Introduction and Key Design Principles

Sustainable Energy Advantage

Background/Introduction

- During the 2021 REG program development process, the Rhode Island Public Utilities Commission (PUC) suggested that SEA consider approaches that would better capture the economies of scale associated with solar PV projects
  - Specifically, the PUC suggested approaches to further subdivide the Commercial Solar/Commercial Solar CRDG classes (and therefore enhance the cost-effectiveness of the program to ratepayers)
- After a process to split the Commercial classes into 251-750 kW and 751-999 kW segments, the PUC approved the subdivision for the 2021 program year
- The PUC has authorized OER and the Distributed Generation Board (DG Board) to discuss potential further subdivisions with stakeholders ahead of (potentially) proposing additional subdivisions

Key Design Principles Considered in Proposals for Further Solar Class Subdivisions

- Guiding Principle: Renewable Energy Growth Act Stated Legislative Purpose
  - R.I.G.L. § 39-26.6-1 states, in pertinent part: *The purpose of this chapter is 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.*
- Based on this statutory guidance (and other typical DG program implementation considerations), SEA proposes the following key design principles (in no specific order of importance):
  - Optimization of Statewide Solar Potential
  - Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost
  - Mitigation of Siting Impacts

1. Optimization of Statewide Solar Potential

- Functionally, solar technical potential in a state or region is equal to:
  - Available, non-restricted parcels of land (either greenfield or previously developed/disturbed) and roof space as constrained by
  - The transmission and distribution grid's hosting capacity in the area in question
- Large majority of operational/pending distributed solar capacity in Rhode comprised of 500 kW-10 MW projects on greenfield parcels **in semi-rural and rural areas distant from load**
  - Result is a RI-specific National Grid interconnection queue approaching 1 GW
- Development of 500 kW-10 MW projects **further challenged by the concurrent development of non-DG projects >10 MW**
  - These projects = driven by a mix of state-level procurements and merchant economics, and can consume large amounts of existing transmission hosting capacity
- These concurrent patterns trigger expensive, time-consuming T&D impact studies that, over time, will **likely pose increasing (and potentially fatal) risks to REG and net metering projects >1 MW under development**

1. Optimization of Statewide Solar Potential (Cont'd)

- Experience in MA, ME, and VT suggests that **unabated development of larger-scale projects in saturated areas is likely to result in adverse impacts** for relatively large groups of projects that will result in either untenable delays or unaffordable costs
  - In Central/Western Massachusetts (or Eversource East), these dynamics will likely result in costs high enough, delays long enough, and sufficient tax credit eligibilities lost that **multiple hundreds of MW of projects in a late stage of development will be cancelled**
- Therefore, policies w/features encouraging development of larger projects distant from load (and tacitly discourage development on rooftops (or smaller, disturbed parcels closer to load) will, all other factors equal:
  - **Limit and/or sub-optimize the state's solar potential**; and
  - **Create a challenging development climate** characterized by increasing investment risks
- Therefore, subdivision options should **ensure balanced deployment of larger projects with development of diverse array of projects sited closer to load**

2. Capturing Appropriate Economies of Scale/Mitigation of Costs to Ratepayers

- Economic efficiency (and ratepayer cost mitigtion) also dictates the design of size bins that reflect appropriate break points for upfront capital and non-capital (operating) costs
- This principle favors subdivision options that **favor resources that maximize returns to scale, but that do not crowd out development of projects that can optimize statewide potential**
  - In terms of implementation, this principle favors **options with the proxy project size (for modeling) at the top end of the range** (to capture maximum benefit of economic efficiency)

2. Capturing Appropriate Economies of Scale/Mitigation of Costs to Ratepayers (Cont'd)

- Feedback from Market Participants (from Data Request and Survey)
  - In addition to the maximum size bin limits that exist today (250 kW, 750 kW, 999 kW, 5 MW), other inflection points for both capital and operating costs include:
    - ~100-150 kW;
    - ~500 kW; and
    - At several points between 1-5 MW (with the greatest frequency of response around 2 MW)

	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 Response(s) (by Capacity)	250 kW	1 MW	2 MW	3 MW	5 MW

3. Minimization of Siting Impacts

- With increasing large-scale and DG solar development has come increased levels of local disagreements over siting, especially in Western RI (where hosting capacity also constrained)
- **The strong economic incentives described in #2 still tilt development economics towards larger-scale DG (>1 MW) projects**
  - Such projects are often sited near residential areas or sensitive ecosystems, **provoking siting conflicts**
- Minimization of siting impacts (through mitigation of siting conflicts and ecosystem disruption) can be achieved by:
  - **Favoring projects sized for most medium/large rooftops** (such as those <=500 kW); and
  - **Carports** (which tend to be <=1 MW, but are always on disturbed parcels)

Potential (Non-Status Quo) Solar Class Subdivision Options

Sustainable Energy Advantage

Subdivision Option A

2021 PY (Status Quo)			2022 PY (Option A)		
Renewable Energy Class	***Size Bin***	***Modeled Size***	***Renewable Energy Class***	***Size Bin***	***Modeled Size***
Small Solar I	1-15 kW	5 kW	Small Solar I	1-15 kW	Average in REG and NEM
Small Solar II	15-25 kW	25 kW	Small Solar II	15-25 kW	25 kW
Medium Solar	26-250 kW	250 kW	Medium Solar	26-250 kW	250 kW
Commercial Solar	251-750 kW	500 kW	**Commercial Solar**	**251-999 kW**	**999 kW**
	751-999 kW	900 kW			
Large Solar	1-5 MW	4,500 kW	**Large Solar**	**1-5 MW**	**5 MW**

Qualitative Evaluation of Subdivision Option A

Design Principle	Comparison of Option to Status Quo

Optimization of Statewide Solar Potential	• Re-establishing 251-999 kW Commercial range (with a 999 kW proxy size) for modeling) would likely **skew development towards 999 kW projects, driving development to larger parcels in rural or semi-rural places already lacking hosting capacity**
	
	• However, impact on statewide technical potential could be mitigated by:
	  • **Increasing capacity allocations to Medium and Commercial projects** relative to status quo; and
	  • **Reducing capacity allocated to Large Solar**

Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost	• Wider-range Commercial class would, by **not incentivizing development at any inflection points between 251 kW and 999 kW, likely reduce ratepayer costs** relative to the status quo • However, as discussed above, such reductions **may not be sustainable if they are paired with losses in statewide technical potential**

Mitigation of Siting Impacts	• Encouraging larger projects could both
	  • **Exacerbate local siting conflicts;** and
	  • (Depending on the parcel) **incrementally disturb a larger number of sensitive ecosystems**

Subdivision Option B

2021 PY (Status Quo)			2022 PY (Option B)		
Renewable Energy Class	***Size Bin***	***Modeled Size***	***Renewable Energy Class***	***Size Bin***	***Modeled Size***
Small Solar I	1-15 kW	5 kW	Small Solar I	1-15 kW	Average in REG and NEM
Small Solar II	15-25 kW	25 kW	Small Solar II	15-25 kW	25 kW
Medium Solar	26-250 kW	250 kW	Medium Solar	26-250 kW	250 kW
Commercial Solar	251-750 kW	500 kW	**Commercial Solar I**	**251-750 kW**	**750 kW**
	751-999 kW	900 kW	**Commercial Solar II**	**751-999 kW**	**999 kW**
Large Solar	1-5 MW	4,500 kW	**Large Solar**	**1-5 MW**	**5 MW**

Qualitative Evaluation of Subdivision Option B

Design Principle	Comparison of Option to Status Quo
Optimization of Statewide Solar Potential	• Option would still limit solar potential relative to the status quo, even though an increase in the proxy system size to 750 kW would **better utilize the state's technical potential (by pushing incrementally less capacity towards areas with more limited hosting capacity)** • Developers **would be incentivized to develop at 750 kW (a value higher than the current proxy size for the 251-750 kW category), potentially increasing risks to technical potential relative to the status quo** • Same caveats regarding mitigation of impacts by sculpting capacity allocations to favor Medium and Commercial (over Large)
Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost	• Increasing proxy system sizes would likely result in **slightly more direct ratepayer benefit relative to the status quo (but less than Option A)**
Mitigation of Siting Impacts	• Could **incrementally stem ecosystem losses (through incentivization of slightly smaller projects)** relative to Option A

Subdivision Option C

2021 PY (Status Quo)			2022 PY (Option C)		
Renewable Energy Class	***Size Bin***	***Modeled Size***	***Renewable Energy Class***	***Size Bin***	***Modeled Size***
Small Solar I	1-15 kW	5 kW	Small Solar I	1-15 kW	Average in REG and NEM
Small Solar II	15-25 kW	25 kW	Small Solar II	15-25 kW	25 kW
Medium Solar	26-250 kW	250 kW	**Medium Solar I**	**26-150 kW**	**150 kW**
			Medium Solar II	151-250 kW	250 kW
Commercial Solar	251-750 kW	500 kW	**Commercial Solar I**	**251-500 kW**	**500 kW**
	751-999 kW	900 kW	**Commercial Solar II**	**501-999 kW**	**999 kW**
Large Solar	1-5 MW	4,500 kW	**Large Solar**	**1-5 MW**	**5 MW**

Qualitative Evaluation of Subdivision Option C

Design Principle	Comparison of Option to Status Quo
Optimization of Statewide Solar Potential	• Greater (and explicit) allocations within the current Medium Solar class for projects up to 150 kW **likely represents more sustainable use of the state's technical potential than additional development in hosting capacity-constrained areas**
Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost	• Proxy sizes of 150 kW for Medium I and 500 kW for Commercial I would **more closely match market participant-identified economic inflection points** • **Similar ratepayer impact to status quo**, since increase in Large Solar proxy size would likely offset the increased cost of splitting the Medium class • Possible that capacity allocations could (as in 2021 Comm'l CPs) **could be more heavily weighted toward larger Medium II and Commercial II** projects.
Mitigation of Siting Impacts	• Explicit allocations for projects 26-150 kW and 251-500 kW would **likely incentivize development on rooftops**, **incrementally reducing ecosystem disruption and siting conflicts**

Subdivision Option D

2021 PY (Status Quo)			2022 PY (Option D)		
Renewable Energy Class	***Size Bin***	***Modeled Size***	***Renewable Energy Class***	***Size Bin***	***Modeled Size***
Small Solar I	1-15 kW	5 kW	Small Solar I	1-15 kW	Average in REG and NEM
Small Solar II	15-25 kW	25 kW	Small Solar II	15-25 kW	25 kW
Medium Solar	26-250 kW	250 kW	**Medium Solar I**	**26-150 kW**	**150 kW**
			Medium Solar II	151-250 kW	250 kW
Commercial Solar	251-750 kW	500 kW	**Commercial Solar I**	**251-500 kW**	**500 kW**
	751-999 kW	900 kW	**Commercial Solar II**	**501-750 kW**	**750 kW**
			Commercial Solar III	**751-999 kW**	**999 kW**
Large Solar	1-5 MW	4,500 kW	Large Solar	1-5 MW	5 MW

Qualitative Evaluation of Subdivision Option D

Design Principle	Comparison of Option to Status Quo
Optimization of Statewide Solar Potential	• **Incrementally more sustainable use of the state's technical potential than both the status quo and Options A-C** (by better incentivizing projects with design capacities of around 250 kW, 500 kW and 750 kW) • Proxy sizes **match well with typical rooftop, carport and landfill/brownfield sizing**
Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost	• Despite being better matched with market participant-identified inflection points for project economics, option could **materially increase costs to ratepayers** • However, same caveats apply regarding cost mitigation by **weighting capacity to larger project size categories**
Mitigation of Siting Impacts	• Guaranteed allocation for both 251-500 kW and 501-750 kW would likely **drive project development towards smaller parcels of land and/or rooftops/carports/small disturbed parcels** less likely to attract siting conflicts

Subdivision Option E

2021 PY (Status Quo)			2022 PY (Option E)		
Renewable Energy Class	***Size Bin***	***Modeled Size***	***Renewable Energy Class***	***Size Bin***	***Modeled Size***
Small Solar I	1-15 kW	5 kW	Small Solar I	1-15 kW	Average in REG and NEM
Small Solar II	15-25 kW	25 kW	Small Solar II	15-25 kW	25 kW
Medium Solar	26-250 kW	250 kW	**Medium Solar I**	**26-150 kW**	**150 kW**
			Medium Solar II	151-250 kW	250 kW
Commercial Solar	251-750 kW	500 kW	**Commercial Solar I**	**251-500 kW**	**500 kW**
	751-999 kW	900 kW	**Commercial Solar II**	**501-750 kW**	**750 kW**
			Commercial Solar III	751-999 kW	999 kW
Large Solar	1-5 MW	4,500 kW	**Large Solar I**	**1,000-2,000 kW**	**2,000 kW**
			Large Solar II	**2,001-5,000 kW**	**5,000 kW**

Qualitative Evaluation of Subdivision Option E

Design Principle	Comparison of Option to Status Quo
Optimization of Statewide Solar Potential	• Could potentially reduce the number (and size) of the largest Large Solar projects (thereby enhancing hosting capacity) • However, may also provide **limited incremental benefit in terms of reducing strain on areas with limited hosting capacity** (and thus could be a poor use of technical potential).
Capturing Appropriate Economies of Scale/Mitigating Ratepayer Cost	• Represents approach most appropriately matched with all identified inflection points for project economics. • Further subdivision of 1-5 MW projects would **likely increase ratepayer costs relative to both the status quo** but could also be **mitigated by careful design of capacity allocations**. • However, shifting capacity allocations to larger projects to reduce ratepayer costs **could raise some questions about overall value of having a 1-2 MW category**
Mitigation of Siting Impacts	• Further **subdivision of 1-5 MW projects could potentially (but not certainly) increase focus on a larger number of parcels** sited in semi-rural and rural areas at **elevated risk of siting conflicts and ecosystem impacts**.

Request for Comments

- **No later than August 20, 2021, SEA requests <u>written</u> comment regarding which of Options A-E you/your firm would favor, and why.**
- **Please send all written comments in the form of a PDF (on company or other official letterhead, if possible)** to me (Jim Kennerly, jkennerly@seadvantage.com), Jason Gifford (jgifford@seadvantage.com) and Toby Armstrong (tarmstrong@seadvantage.com) at SEA, as well as to Chris Kearns (Christopher.Kearns@energy.ri.gov) and Shauna Beland (Shauna.Beland@energy.ri.gov) at OER.

Appendix: 2022 1st Draft Ceiling Price Bid Data, Regional Benchmarking, and Additional Assumptions

Sustainable Energy Advantage, LLC

Overview of Research to Inform CP Inputs

- Direct stakeholder input
  - Through *Data Request* _and_ *Survey*
- Supplemental research
  - Interviews
  - Program data (bids, executed contracts)
  - Additional data from National Grid (Interconnection costs, production data)
  - Northeast regional cost databases
  - Revealed pricing data for <=25 kW system from EnergySage
  - Northeast data from national reports (LBNL *Tracking the Sun*)
- REG bid data (2015-2020 Open Enrollments and 1st Open Enrollment of 2021)

Small Solar I, Installed Costs

Small Solar I, Installed Costs								
1-15 kW								
	2020 (Full Year)				2021 (6 Months)			
Dataset	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)
NY - NYSERDA Solar Electric Programs	$4,109	$3,800	$3,163	$4,613	$4,043	$3,744	$3,128	$4,601
MA Smart (Qualified & Operational)	$4,551	$4,509	$3,635	$5,231	$4,615	$4,466	$3,925	$5,067
CT Residential Solar Investment Program	$3,672	$3,652	$3,197	$4,219	$3,623	$3,590	$2,919	$4,283
State Database Averages	$4,111	$3,987	$3,332	$4,687	$4,094	$3,934	$3,324	$4,650
Energy Sage - RI Accepted	$3,068				$3,188			
Energy Sage - MA Accepted	$2,972				$2,916			
Energy Sage - NY Accepted	$3,139				$3,130			
Energy Sage - CT Accepted	$2,830				$2,923			
Energy Sage - RI All (inc. non-selected)	$3,056				$3,129			
Energy Sage Accepted Averages	$3,002				$3,039			
REF Data	$3,486	$3,405	$3,094	$3,769	$4,055	$3,459	$3,152	$3,569
Small Scale REG enrollments	$5,337	$4,747	$3,996	$5,357	$4,677	$4,860	$3,452	$5,416
LBNL TTS - RI	$4,445	$4,277	$3,450	$5,013	no data	no data	no data	no data
LBNL TTS - All NE States	$4,013	$3,800	$3,200	$4,522	no data	no data	no data	no data

Datasets: NY (NYSERDA Solar Programs 2019-2020 data), CT (Residential Solar Investment Program), MA SMART data, EnergySage revealed pricing data, RI Renewable Energy Fund, LBNL *Tracking the Sun*

Small Solar II, Installed Costs

Small Solar II, Installed Costs								
15-25 kW								
	2020 (Full Year)				2021 (6 Months)			
Dataset	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)
NY - NYSERDA Solar Electric Programs	$3,234	$3,041	$2,628	$3,650	$3,359	$3,148	$2,599	$3,810
MA Smart (Qualified & Operational)	$4,293	$4,329	$3,913	$4,655	$4,125	$3,898	$3,402	$4,956
CT Residential Solar Investment Program	$3,361	$3,435	$2,949	$3,787	$3,306	$3,299	$2,667	$3,932
State Database Averages	$3,629	$3,602	$3,164	$4,031	$3,597	$3,448	$2,889	$4,233
Energy Sage - RI Accepted	$2,759				$2,757			
Energy Sage - MA Accepted	$2,694				$2,810			
Energy Sage - NY Accepted	$2,930				$3,020			
Energy Sage - CT Accepted	$2,594				$2,768			
Energy Sage - RI All (inc. non-selected)	$2,778				$2,756			
Energy Sage Accepted Averages	$2,744				$2,839			
REF Data	$3,328	$3,300	$2,960	$3,590	$3,469	$3,469	$3,469	$3,469
Small Scale REG enrollments	$2,748	$4,100	$3,365	$5,107	$3,204	$3,204	$3,202	$3,205
LBNL TTS - RI	$3,733	$3,615	$3,026	$4,533	no data	no data	no data	no data
LBNL TTS - All NE States	$3,357	$3,259	$2,820	$3,800	no data	no data	no data	no data

Datasets: NY (NYSERDA Solar Programs 2019-2020 data), CT (Residential Solar Investment Program), MA SMART data, Energy Sage revealed pricing data, RI Renewable Energy Fund, LBNL *Tracking the Sun*

Medium, Commercial, and Large Solar Installed Costs

Medium Solar, Installed Costs 25-250 kW	2020 (Full Year)				2021 (6 Months)			
Dataset	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)
NY - NYSERDA Solar Electric Programs	$3,089	$2,794	$2,365	$3,665	$3,516	$3,269	$2,441	$4,722
CT Residential Solar Investment Program	$2,399	$2,445	$2,309	$2,617	No Data	No Data	No Data	No Data
RI REG Bids	$2,253	$2,388	$2,071	$2,405	$2,240	$2,162	$1,996	$2,483
LBNL - RI only	$3,187	$3,167	$2,851	$3,633	no data	no data	no data	no data
LBNL - all NE states	$2,817	$2,571	$2,170	$3,114	no data	no data	no data	no data

Commercial Solar, Installed Costs 251-999 kW	2020 (Full Year)				2021 (6 Months)			
Dataset	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)
NY - NYSERDA Solar Electric Programs	$2,333	$2,316	$2,100	$2,600	$2,144	$2,100	$1,879	$2,502
RI REG Bids	$2,037	$2,034	$1,886	$2,112	$6	$1,741	$1,741	$1,470
LBNL - all NE states	$2,069	$1,946	$1,712	$2,362	no data	no data	no data	no data

Large Solar, Installed Costs 1000-5000+ kW	2020 (Full Year)				2021 (6 Months)			
Dataset	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)	Average ($/kW)	Median ($/kW)	25th Percentile ($/kW)	75th Percentile ($/kW)
NY - NYSERDA Solar Electric Programs	$1,353	$1,201	$1,115	$1,430	$1,265	$1,231	$1,002	$1,351
CT Residential Solar Investment Program	No Data	No Data	No Data	No Data	No Data	No Data	No Data	No Data
RI REG Bids	$1,386	$1,216	$1,207	$1,590	$1,440	$1,440	$1,440	$1,440
LBNL - all NE states	$1,860	$1,673	$1,447	$2,121	no data	no data	no data	no data

Note: Due to constrained sample size, we pooled data from both commercial size bins in analysis. Median installed cost values were used to compute the 251-750 kW cost inputs, whereas 75th percentile data was used for 751-999 kW cost inputs

Datasets: NY (NYSERDA Solar Programs), RI Renewable Energy Growth bids for 2020-2021 enrollments, LBNL Tracking the Sun

Average & Median Installed Cost/kW for RI REF Data (2019-2020)

Installed Cost Analysis of Renewable Energy Fund (REF) Systems 1-25 kW, 2019-2020										
	2020					2021				
	Average cost ($/kW)	Median cost ($/kW)	1st Quartile	3rd Quartile	N	Average cost ($/kW)	Median cost ($/kW)	1st Quartile	3rd Quartile	N
1-15 kW	$3,486.07	$ 3,405	$ 3,094	$ 3,769	267	$ 4,055	$ 3,459	$ 3,152	$ 3,569	48
15-25 kW	$3,327.73	$ 3,300	$ 2,960	$ 3,590	9	$ 3,469	$ 3,469	$ 3,469	$ 3,469	1

Note: Data from RI Renewable Energy Fund (CommerceRI).

Interconnection Cost Analysis

	Rhode Island 2020-2021 Projects		
	Number of Projects with Cost Data	Median Cost ($/kW DC)	Average Cost ($/kW DC)
Solar (<25 kW)	6	$132.30	$123.24
Solar (25-250 kW)	24	$193.27	$186.92
Solar (250-1000 kW)	5	$59.95	$113.85
Solar (1000-5000 kW)	23	$136.74	$134.18
Small Wind (<=999 kW)	0	N/A	N/A
Large Wind (1000-5000 kW)	0	N/A	N/A

Note: Based on National Grid Data. Dataset includes additional projects that do not have cost data available.

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Sustainable
Energy
Advantage, LLC

Rhode Island Renewable Energy Growth Program:

Research, Analysis, & Discussion in Support of 2nd Draft 2022 Program Year Ceiling Price Recommendations

September 8, 2021

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Changes in Cost/Performance Assumptions to Incorporate Stakeholder Feedback (from 1st Draft)

Sustainable Energy Advantage, LLC

Subdivision of Solar Renewable Energy Classes

- Stakeholders suggested interest in considering a range of the Options shared on July 27, with Solar developers favoring Options C through E (which would have resulted in more subdivision), while the DPUC favored Option C
  - No stakeholders suggested adopting Options A or B (which would have limited the scope of existing subdivisions or made proxy sizes within existing subdivisions more aggressive)
- Greatest overlap in preferences between the two key groups was **Option C**, which introduces a new subdivision to the Medium Solar category
- **Multiple Modeling Implications (M.I.s):**
  - **Provisionally adopt Option C, resulting in the following >25 kW Solar renewable energy classes:**
    - **Medium I (26-150 kW bin w/150 kW proxy size)**
    - **Medium II (151-250 kW bin w/250 kW proxy size)**
    - **Commercial I & Commercial I CRDG (251-500 kW bin w/500 kW proxy size)**
    - **Commercial II & Commercial II CRDG (501-999 kW bin w/999 kW proxy size)**
    - **Large Solar (1-5 MW, 5 MW proxy size)**
  - **Medium Solar capital cost inputs based on: 1) 50th percentile of bid and state database (DB) values for 26-250 kW range (Medium I) and 2) 25th percentile of bid/state DB values for 26-250 kW range (Medium II)**
  - **Commercial Solar capital cost inputs based on 1) 50th percentile bid/state DB values for 251-500 kW range (Commercial I) and 2) 25th percentile bid/state DB values for 501-999 kW range (Commercial II)**

Proposed Ceiling Price Categories

2022 REG Program: Proposed Technology, Size & Tariff Length Parameters			
Eligible Technology	**Modeled Size**	**Eligible System Size Range**	**Tariff Length**
Small Solar I	5.8 kW_{DC}	≤15 kW_{DC}	15 Years
Small Solar II	25 kW_{DC}	>15 to 25 kW_{DC}	20 Years
Medium Solar I	150 kW_{DC}	>25 to 150 kW_{DC}	20 Years
Medium Solar II	250 kW_{DC}	>150 to 250 kW_{DC}	20 Years
Commercial Solar I	500 kW_{DC}	>250 to 500 kW_{DC}	20 Years
Commercial Solar I – Community Remote DG (CRDG)	500 kW_{DC}	>250 to 500 kW_{DC}	20 Years
Commercial Solar II	999 kW_{DC}	>500 to 1,000 kW_{DC}	20 Years
Commercial Solar II – Community Remote DG (CRDG)	999 kW_{DC}	>500 to 1,000 kW_{DC}	20 Years
Large Solar	5,000 kW_{DC}	>1 to 5 MW_{DC}	20 Years
Large Solar - CRDG	5,000 kW_{DC}	>1 to 5 MW_{DC}	20 Years
Wind	3,000 kW_{AC}	≤5 MW_{AC}	20 Years
Anaerobic Digestion	750 kW_{AC}	≤5 MW_{AC}	20 Years
Hydropower	500 kW_{AC}	≤5 MW_{AC}	20 Years

NOTE: Red text = Proposed changes relative to 1st Draft of 2022 Ceiling Prices

Potential for Administratively-Set Pricing for Certain Medium Solar Projects

- At present, the Medium Solar category is subject to competitive procurement, which is allowed (but not required) under the Renewable Energy Growth Act
- Stakeholders have frequently suggested that SEA consider recommending that the PUC re-adopt an administratively-set price for Medium Solar projects, arguing that the infrequent nature of Open Enrollments add an element of time and uncertainty that can make finalizing deals much more difficult
- **M.I.: OER has advised SEA that it is not currently considering adjustments to the approach for compensating/soliciting projects in the Medium Solar category**

Accounting for Project Cost Pressures

- Stakeholders have identified broadly-applicable cost pressures across resource types resulting from COVID-19 pandemic and other economic recovery-related factors
  - Solar stakeholders have suggested a 5%-15% increase across the board for projects under development for next year
  - Independent wind market stakeholders have suggested 2022 project costs are likely to increase 10%
  - Hydro stakeholders have suggested a 30% increase year-on-year
- Drivers are wide-ranging, from high shipping costs/delays, increases in commodity inputs for manufacturing (e.g. polysilicon and steel)
- **Multiple M.I.s: Utilize forecasted Producer Price Index (PPI) change from 2020 to 2022 (+10% in the most recent EIA Short-Term Energy Outlook (STEO)) as an adder to non-interconnection installed costs, which is (for Solar only) offset by range of values from NREL ATB "Conservative" and "Moderate" cases (see next page for more detail)**

Detailed M.I.s for Project Cost Pressure Accounting

Technology	Category	△ Project Cost *Before* Impact of PPI	△ Project Cost *After* Impact of PPI
Solar	Small I / II	-4.3% to -9.9%	0% to 6%
	Medium, Commercial, Comm. CRDG	-4.3% to -8.0%	2% to 6%
	Large, Large CRDG	-4.0% to -7.4%	2.6% to 6%

- **Wind and AD**
  - **10% increase (per PPI) in non-interconnection installed costs (not offset by cost declines)**
- **Hydro**
  - **Set tentatively at 20% increase (average of industry stakeholder estimate and PPI), and request further comments/information from hydro stakeholders**

Note: In presented results, we refer to the cases utilizing the Conservative ATB case as "High Cost" and the cases utilizing the Moderate ATB case as "Low Cost"

Year 1 Capacity Factor Adjustment for Solar <=25 kW

- DPUC filed comments supporting an averaging of estimated (14.0%) and actual values observed by National Grid (12.8%) for Year 1 capacity factors for Small Solar projects, but suggested that National Grid provide more information to support the actual values
  - No stakeholders other than the DPUC commented on this subject
- **M.I.: Utilize average of 2021 CP final CF of 14.0% and National Grid observed figure of 12.8% (resulting in 13.4% value), but subject to change based on further examination of National Grid data, if needed**

Solar Production Degradation

- DPUC indicated support for taking the first step of a potential two-step approach to phase in production degradation changes observed in SEA's data analysis of DG projects in Massachusetts
  - Other than the DPUC, no stakeholders commented on degradation percentages
- **M.I.: Adopt following degradation percentages:**
  - **Small I/II: 1.0% (up from 0.5% in 2021 CPs)**
  - **Medium and Commercial/Commercial CRDG: 0.8% (up from 0.5% in 2021 CPs)**
  - **Large/Large CRDG: 0.5% (unchanged from 2021 CPs)**

Post-Tariff Revenue Assumptions

- State law allows projects to receive net metering compensation following the REG tariff term
  - Initial draft 2022 prices included a 40% discount to net metering revenue earned after the tariff expires, to account for both market and policy-related uncertainty associated with net metering rates and availability.
- Two commenters (including the DPUC) supported smaller discounts (closer to 10%-20%)
- **Consulting Team Note:** A developer that assumes a smaller discount (especially for non-Small projects) could potentially cause more sophisticated financiers (and especially debt providers) to contribute less capital to a project, given that they may perceive more risk to their revenue streams
  - It is possible that this reduced injection of capital by debt providers could increase (all factors equal) the project's consolidated after-tax IRR by an amount greater than the reduction associated with a smaller haircut (<u>and thus increase the net cost to ratepayers</u>)
- **M.I.: No immediate change to 40% discount, but SEA will request comments from stakeholders regarding the interaction of the proposed discount and the availability of investment capital.**

Project Useful Life Assumptions

- DPUC has proposed assuming 30-year useful lives for Commercial and Large Solar categories (a move potentially justified by recent LBNL analysis) with 25-year useful lives for Small and Medium projects (citing their typical placement on rooftops that often require replacement more frequently than 30 years)
- However, National Grid data from 2018-2020 presented to the DG Board shows that most Commercial projects are sited on rooftops (and are not ground-mounted)
    - The same National Grid data linked above shows that all Large Solar projects 2018-2020 are ground mounted (obviating the need for a deviation from the 30-year useful life assumption)
- Another Wind stakeholder suggested that because product warranties did not last beyond 15 years that Wind useful lives should not extend to 30 years (despite other related LBNL analysis)
    - We note that Solar project equipment typically has warranties of ~10-15 years (for which extended coverage periods are available at a price that some choose to pay, while others do not).
    - Nevertheless, no other market participants have suggested to us that initial manufacturer warranties should reduce the term of their useful lives to an amount close to (or commensurate with) said warranties.
- **Multiple M.I.s: Adopt 30-year useful life for Large Solar/Large CRDG, but continue to assume 25-year useful lives for all Small, Medium and Commercial Solar classes as in the 1st Draft of 2022 Ceiling Prices. Also, continue to assume 30-year life for Wind projects.**

Operating Expense Assumptions (1)

- Insurance
  - More than one developer provided documented insurance quotes demonstrating increases associated with both liability and property insurance
  - Increases generally understood to correspond to larger number of payouts across insurance industry generally in past several years
  - **M.I.: Increase insurance inputs 27% for Solar and 47% for Non-Solar projects**
- Project Management
  - A Large Solar/Large CRDG developer has provided documentary evidence of asset management agreement costs ranging from $4,000-$5,000/MW
  - **M.I.: Adjust Large Solar/Large CRDG project management costs (functionally, asset management agreement costs) to lower end of developer estimate, resulting in annual costs of $20,000 (from $12,000)**

Operating Expense Assumptions (2)

- Solar Land/Site Lease
  - A Large Solar/Large CRDG developer has provided documentary evidence of a lease with a $17,000/MW-yr cost
  - A Medium Solar developer also provided documentary evidence of a lease with a total cost of $18,000/project/yr
  - A Wind developer further provided documentary evidence of a lease with a total cost of $22,000/project/yr
- **Multiple M.I.s:**
  - **Increase lease payment input for Large Solar/Large CRDG to $67,500 (from $50,000), representing average of prior input and stakeholder data**
  - **Increase lease payment input for Medium Solar II to $15,000 (from $12,000), representing average of prior input and stakeholder data**
  - **Increase lease payment input for Medium Solar I to $7,500 (half of value for Medium Solar II), to reflect smaller project size / increased probability for roof mounting**
  - **No change to Wind payment (given proxy size used for modeling is for a larger system with much larger (>$150k/yr) lease payment)**

Small Solar I/II Financing Assumptions

- Consulting team had held open Data Request and Survey in order to collect more information, but no one else responded
- One developer suggested an after-tax equity IRR of 10% is more reasonable
- However, the changes to the Year 1 Capacity Factor and degradation rates will also substantially increase compensation for Small Solar I/II projects (to a level close to a return of 10% relative to prior year prices)
- **M.I.: No change from 1st round, but additional adjustments may be forthcoming if further Small Solar stakeholders provide information**

Other Issues (1)

- Installed Cost Inputs from New York State
  - One developer suggested that installed costs from NYS were not accurately calculated and should be lower
  - However, developer estimate assumed an <u>average</u> cost, rather than the 75th percentile assumption we utilize to balance out the impact of upstate projects with substantially lower land and materials costs (thus out of line with economics in RI)
  - **M.I: No change.**
- Averaging of 100% bonus and MACRS depreciation for Wind
  - Consulting team inadvertently did not include an averaging of the 100% bonus depreciation and 5-year MACRS cases in 1st Round of prices
  - **M.I.: Wind and Wind CRDG prices now incorporate averaged value of 100% bonus and 5-year MACRS**

Other Issues (2)

- Affected System Operator (ASO) Study Cost
  - Consulting team has learned that the one-time cost of participating in an ASO study (exclusive of any identified system modifications) is $6,500/MW
  - **M.I.: Study cost is now built into Ceiling Prices for classes with eligible projects larger than 1 MW_{AC}, to match with ISO-NE ASO analysis thresholds**
- Assumption of Project Debt
  - One developer suggested that it is unreasonable to assume projects can access debt, arguing that some debt providers require investment in a portfolio of projects (rather than just a one-off project)
  - **M.I.: No change. It is our understanding that access to debt is not an issue or concern for developers in Rhode Island, and assuming no debt in the capital stack could lead to developer windfalls at the expense of ratepayers**

Issues for Final Round of Prices

- National Electric Code
  - SEA has been apprised that there will be several changes in NEC20 affecting solar installations. These changes would become effective in 2022
  - **M.I.: No change for current round, but will investigate for final round**
- Tangible Taxes
  - SEA has received compelling evidence that in certain circumstances, municipalities increase the assumed value of land when a renewable energy project is placed upon it in order to collect higher taxes from said project
  - However, SEA has not been able to verify the prevalence of this approach throughout RI
  - **M.I.: No change for current round, but plan remains to develop an approach for final round of prices**
- Residential Interconnection Costs
  - **M.I.: No change, additional information needed prior to making any decision**

2nd Draft 2022 Ceiling Prices

Sustainable Energy Advantage, LLC

Summary Results (1): Solar (¢/kWh)

Technology	Tariff Term (Years)	Size Range kW_{DC} (Modeled Size kW_{DC})	2021 Approved CP	2022 1st Draft Proposed CP (w/ and w/o Year-on-Year (YoY) Solar Capital Cost Adjustment)	2022 2nd Draft Proposed CP (Low-Cost Case)	2022 2nd Draft Proposed CP (High-Cost Case)
Small Solar I	15	1-15 (5.8)	28.75	26.85 - 27.85 (-7% / -3%)	**30.45 (6%)**	**32.25 (12%)**
Small Solar II	20	>15-25 (25)	24.35	24.25 - 25.05 (-0.4%/3%)	**27.05 (11%)**	**28.45 (17%)**
Medium Solar I	20	>25-150 (150)	21.65	N/A (New RE Class)	**26.25 (21%)**	**26.95 (24%)**
Medium Solar II	20	>150-250 (250)	21.65	21.35 - 22.05 (-1%/2%)	**24.15 (12%)**	**24.75 (14%)**
Commercial Solar I	20	>250-500 (500)	18.55	17.55 - 18.15 (-5%/-2%)	**19.05 (3%)**	**19.55 (5%)**
Commercial Solar I -CRDG	20	>250-500 (500)	21.33	20.18 - 20.87 (-5%/-2%)	**21.91* (3%)**	**22.48* (5%)**
Commercial Solar I	20	>501-1,000 (1,000)	15.25	14.55 -15.05 (-5%/-1%)	**15.55 (2%)**	**16.05 (5%)**
Commercial Solar II -CRDG	20	>501-1,000 (1,000)	17.54	16.73 - 17.31 (-5%/-1%)	**17.88* (2%)**	**18.46* (5%)**
Large Solar	20	>1,000-5,000 (5,000)	11.35	9.95 - 10.35 (-12%/-9%)	**10.75 (-5%)**	**11.25 (-3%)**
Large Solar-CRDG	20	>1,000-5,000 (5,000)	13.05	11.44 - 11.90 (-12%/-9%)	**12.59* (-5%)**	**12.94* (-3%)**

*This is the maximum CRDG Ceiling Price allowed by law. The calculated 2022 values are (depending on if the capital cost case is high or low) between 22.55 and 22.05 for Commercial CRDG 251-500, 19.05 and 18.65 for Commercial CRDG 501-999 and 14.85 and 14.55 for Large CRDG. Note, however, that this CP would allow cost-competitive projects (bidding below the CP) access to > a 15% premium compared to actual project costs.

Summary Results (2): Wind, Hydro & AD (cents/kWh)

Technology	Tariff Term (Years)	Size Range kW_{AC} (Modeled Size kW_{AC})	2021 Approved CP	2022 1st Draft Proposed CP	2022 2nd Draft Proposed CP
Wind	20	≤5,000 (3,000)	18.75	**20.75 (11%)***	**22.05 (18%)**
Wind - CRDG	20	≤5,000 (3,000)	21.05	**22.85 (9%)***	**24.25 (15%)**
Hydroelectric	20	≤5,000 (500)	27.35	**27.75 (2%)***	**36.85 (35%)**
Anaerobic Digestion	20	≤5,000 (750)	15.85	**22.45 (41%)***	**25.15 (59%)**

*Increases in Ceiling Prices for non-Solar technologies driven mainly by the expiration of the PTC and resulting changes in financing assumptions
**SEA discovered a modeling error exclusive to our Anaerobic Digestion model that resulted in the 1st Draft Proposed CP being erroneously low. The corrected value is displayed above.

Revised Modeling Parameters

Sustainable Energy Advantage, LLC

Summary: Cost & Production Assumptions (Solar)

	Small I	Small II	Medium I	Medium II	Comm'l I	Comm'l I (CRDG)	Comm'l II	Comm'l II (CRDG)	Large	Large CRDG
Nameplate Capacity (kW)	5.8 [5]	25	150	250	500	500	1,000 [900]	1,000 [900]	5,000 [4,500]	5,000 [4,500]
Capacity Factor	13.4% [14.0%]	13.4% [14.0%]	14.5%	14.5%	14.6%	14.6%	14.6%	14.6%	15.10%	15.10%
Annual Degradation	1.0% [0.5%]	1.0% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.5%	0.5%
Useful Life (Years)	25	25	25 [20]	25 [20]	25 [20]	25 [20]	25 [20]	25 [20]	30 [25] [20]	30 [25] [20]
Total Cost w/ Low Cost Adjustment^ ($/kW)	$3,310 [$3,195] [$3,146]	$3,042 [$2,935] [$2,883]	$2,739 [N/A] [N/A]	$2,361 [$2,211] [$2,332]	$2,068 [$1,936] [$2,097]	$2,168 [$2,036*] [$2,247*]	$1,901 [$1,780] [$1,869]	$2,001 [$1,880*] [$2,019*]	$1,411 [$1,313] [$1,492]	$1,511 [$1,413*] [$1,642*]
Total Cost w/ High Cost Adjustment^ ($/kW)	$3,510 [$3,311] [$3,146]	$3,224 [$3,042] [$2,883]	$2,846 [N/A] [N/A]	$2,454 [$2,315] [$2,332]	$2,149 [$2,027] [$2,097]	$2,249 [$2,127*] [$2,247*]	$1,975 [$1,863] [$1,869]	$2,075 [$1,963*] [$2,019*]	$1,458 [$1,375] [$1,492]	[$1,558 $1,475*] [$1,642*]
Fixed O&M ($/kW-yr)	$29 [$35]	$24 [$35]	$14.57	$14.57	$12.03	$34.03 [$37.03]	$12.03	$34.03 [$37.03]	$8.00 [$12.03]	$30.00 [$37.03]
O&M Escalation Factor	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.34% [0.27%]	0.34% [0.27%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]
Project Management ($/yr)	$0	$0	$3,000	$3,000	$4,000	$4,000	$4,000	$4,000	$20,000 [$12,000]	$20,000 [$12,000]
Site Lease ($/yr)	$0	$0	$7,500 [$12,000]	$15,000 [$12,000]	$20,000	$20,000	$20,000	$20,000	$67,500 [$50,000]	$67,500 [$50,000]

Values in [Blue Brackets] represent 2021 ceiling price inputs, Values in [Green Brackets] represent Draft 1 inputs that were revised for Draft 2

* Reflects installed cost of non-CRDG project from same category, plus estimated cost of customer acquisition ($100/kW, previously $150/kW)

^ Total cost includes interconnection cost

Summary: Cost & Production Assumptions
Wind, Hydro, and AD

	Wind	Large Wind - CRDG	Hydroelectric	Anaerobic Digestion
Nameplate Capacity (kW)	3,000	3,000	500	725
Capacity Factor	21.00%	21.00%	55.00%	92%[1]
Annual Degradation	0.5%	0.5%	0.0%	0.0%
Total Cost ($/kW)	$3,102 [$2,820]	$3,202 [$2,970]	$11,824 [$9,931]	$11,150 [$10,150]
Fixed O&M ($/kW-yr)	$26.50	$48.50 [$51.50]	$2.00	$600
O&M Inflation	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.29% [0.20%]	0.29% [0.20%]	4.0% [2.7%]	1.5% [1.0%]
Project Management ($/yr)	$18,000	$18,000	$3,000	$75,000
Site Lease ($/yr)	$162,000	$162,000	$8,750	$35,000

1. *Note: For Anaerobic Digestion we use an Availability Factor*

Values in [Blue Brackets] represent 2021 ceiling price inputs, Values in [Green Brackets] represent Draft 1 inputs that were revised for Draft 2

Summary: Financing Assumptions (Small Solar)

	Small I		Small II	
	2021 Final	***2022 1st Draft & 2nd Draft***	***2021 Final***	***2022 1st Draft & 2nd Draft***
Federal Investment Tax Credit (%)	26%	**26%**	26%	**26%**
% Debt	71%	**60%**	60%	**50%**
Debt Term (years)	13	**13**	10	**10**
Interest Rate on Term Debt	6.3%	**6.3%**	7.0%	**7.0%**
Lender's Fee (% of total borrowing)	4.25%	**4.25%**	2.3%	**2.3%**
Target After-Tax Equity IRR	5.2%	**7%**	13.0%	**12.5%**

Summary: Financing Assumptions (Solar >25 kW)

	Medium		Comm'l & Comm'l CRDG		Large & Large CRDG	
Assumption Set	***2021 Final***	***2022 1st Draft & 2nd Draft***	***2021 Final***	***2022 1st Draft & 2nd Draft***	***2021 Final***	***2022 1st Draft & 2nd Draft***
Federal Investment Tax Credit (%)	26%	**26%**	26%	**26%**	26%	**26%**
% Debt	55%	**55%**	55%	**55%**	55%	**53%**
Debt Term (years)	15	**15**	15	**15**	15	**15**
Interest Rate on Term Debt	6.0%	**6.6%**	5.25%	**5.85%**	5.25%	**5.85%**
Lender's Fee (% of total borrowing)	1.0%	**1.0%**	1.0%	**1.0%**	2.0%	**2.0%**
% Equity Share of Sponsor Equity	25%	**25%**	25%	**25%**	25%	**25%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	13.5%	**13.0%**	12.5%	**12.0%**	11.5%	**11.0%**
% Equity Share of Tax Equity	75%	**75%**	75%	**75%**	75%	**75%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	**9.5%**	9.5%	**9.5%**	9.5%	**9.5%**
Depreciation Approach	5-Year MACRS	**5-Year MACRS**	5-Year MACRS	**5-Year MACRS**	5-Year MACRS	**5-Year MACRS**

Summary: Financing Assumptions (Non-Solar)

	Wind & Wind CRDG		Hydroelectric		Anaerobic Digestion	
Assumption Set	***2021 Final***	***2022 1st Draft & 2nd Draft***	***2021 Final***	***2022 1st Draft & 2nd Draft***	***2021 Final***	***2022 1st Draft & 2nd Draft***
Federal Investment Tax Credit	18%	**0% (Expiring 1/1/2022)**	0% (Available but not Monetizable)	**0% (Expiring 1/1/2022)**	30%	**None (Expiring 1/1/2021)**
% Debt	60%	**60%**	70%	**70%**	45%	**45%**
Debt Term (years)	15	**15**	20	**20**	15	**15**
Interest Rate on Term Debt	6.0%	**6.6%**	6.25%	**7.15%**	6.25%	**6.85%**
Lender's Fee (% of total borrowing)	1.0%	**1.0%**	1.88%	**1.88%**	1.5%	**1.5%**
% Equity Share of Sponsor Equity	25%	**60%**	100%	**80%**	20%	**60%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	12.5%	**12.0%**	12.5%	**12.0%**	12.5%	**12.0%**
% Equity Share of Tax Equity	75%	**40%**	0%	**20%**	0%	**40%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.0%	**9.5%**	9.0%	**9.5%**	9.0%	**9.5%**
Depreciation	5-Year MACRS	**Average of 100% bonus and 5-Year MACRS**	7-year MACRS	**7-year MACRS**	5-year MACRS	**5-year MACRS**

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Sustainable
Energy
Advantage, LLC

Rhode Island Renewable Energy Growth Program:

Research, Analysis, & Discussion in Support of Final Recommended Ceiling Prices for the 2022 Program Year

October 25, 2021

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

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Additional Stakeholder Engagement & Results

- Consulting team engaged extensively with the Division of Public Utilities and Carriers (DPUC), throughout the process
- The final Ceiling Prices reflect a substantial degree of their input, as well as input from industry stakeholders on subjects that include (but are not limited to):
  - Accounting for cost increases associated with substantial supply chain distortions related to the shifting nature of the COVID-19 pandemic (particularly in Asia);
  - Further subdivision of the Solar renewable energy classes to simultaneously encourage project diversity while limiting ratepayer cost;
  - Reductions in Small Solar capacity factors and increased Solar degradation rates (to account for emerging evidence of material real world underperformance relative to forecasts and expectations, especially for Small, Medium and Commercial Solar projects);
  - Longer estimate useful lives for Solar projects;
  - More substantial compensation expectations (based on an updated understanding of Rhode Island statute);

Request for Approval of Final Recommended 2022 PY Ceiling Prices

- OER and the consulting team formally request that the Board approve the Ceiling Prices included (and bolded) on the following slides.
- OER and the consulting team also request (as in past years) that the Board grant latitude to revise the Ceiling Prices as needed to account for any late changes to federal policy, including:
  - The Build Back Better Act (which, if enacted, is likely to contain many changes to renewable energy-relevant tax provisions, is enacted into law); and
  - Potential extensions to current tariffs on important solar PV cells and modules, as well as potential anti-dumping and countervailing duties against Chinese solar manufacturers, which may enter effect prior to the beginning of the 2022 PY (**April 1, 2022**)

Final Recommended Prices for Solar (¢/kWh)

Technology	Tariff Term (Years)	Size Range kW_{DC} (Modeled Size kW_{DC})	2021 Approved CP	2022 1st Draft Proposed CP (w/ and w/o Year-on-Year (YoY) Solar Capital Cost Adjustment)	2022 2nd Draft Proposed CP (w/Low/High Project Cost Range)	2022 Final Recommended CP
Small Solar I	15	1-15 (5.8)	28.75	26.85-27.85 (-7%/-3%)	30.45-32.25 (6%/12%)	**31.05 (8%)**
Small Solar II	20	>15-25 (25)	24.35	24.25-25.05 (-0.4%/3%)	27.05-28.45 (11%/17%)	**27.55 (13%)**
Medium Solar I	20	>25-150 (150)	N/A	N/A (New RE Class)	26.25-26.95	**26.65**
Medium Solar II	20	>150-250 (250)	21.65	21.35-22.05 (-1%/2%)	24.15-24.75 (12%/14%)	**24.45 (13%)**
Commercial Solar I	20	>250-500 (500)	18.55	17.55-18.15 (-5%/-2%)	19.05-19.55 (3%/5%)	**19.25 (4%)**
Commercial Solar I -CRDG	20	>250-500 (500)	21.33	20.18-20.87 (-5%/-2%)	21.91-22.48* (3%/5%)	**22.14* (4%)**
Commercial Solar I	20	>500-1,000 (1,000)	15.25	14.55-15.05 (-5%/-1%)	15.55-16.05 (2%/5%)	**15.75 (3%)**
Commercial Solar II -CRDG	20	>500-1,000 (1,000)	17.54	16.73-17.31 (-5%/-1%)	17.88-18.46* (2%/5%)	**18.11* (3%)**
Large Solar	20	>1,000-5,000 (5,000)	11.35	9.95-10.35 (-12%/-9%)	10.75-11.25 (-5%/-3%)	**10.95 (-4%)**
Large Solar-CRDG	20	>1,000-5,000 (5,000)	13.05	11.44-11.90 (-12%/-9%)	12.59-12.94* (-5%/-3%)	**12.59* (-4%)**

*This is the maximum CRDG Ceiling Price allowed by law. The calculated Final Recommended 2022 values are 22.35 for Commercial CRDG 251-500, 18.85 for Commercial CRDG 501-999 and 14.05 for Large CRDG. Note, however, that this CP would allow cost-competitive projects (bidding below the CP) access to > a 15% premium compared to actual project costs.

Final Recommended Prices for Wind, Hydro & AD (¢/kWh)

Technology	Tariff Term (Years)	Size Range kW_{AC} (Modeled Size kW_{AC})	2021 Approved CP	2022 1st Draft Proposed CP	2022 2nd Draft Proposed CP	2022 Final Recommended CP
Wind	20	≤5,000 (3,000)	18.75	20.75 (11%)*	22.05 (18%)	**22.40 (19%)**
Wind - CRDG	20	≤5,000 (3,000)	21.05	22.85 (9%)*	24.25 (15%)	**24.60 (17%)**
Hydroelectric	20	≤5,000 (500)	27.35	27.75 (2%)*	36.85 (35%)	**37.15 (36%)**
Anaerobic Digestion	20	≤5,000 (750)	15.85	22.45 (41%)*	25.15 (59%)	**25.55 (61%)**

*Increases in Ceiling Prices for non-Solar technologies driven mainly by the expiration of the PTC and resulting changes in financing assumptions

Anticipated Next Steps

- Upon the DG Board's approval, OER anticipates filing the recommended prices, along with supportive testimony, with the Public Utilities Commission (PUC) **no later than November 2021**
- Based on past practice by the PUC, OER further anticipates a public hearing that typically takes place in either **late January or early February 2022**
- By statute, the PUC must approve the tariffs **no later than February 15** of each year, ahead of the start of the program year on **April 1**

Appendix A: Changes in Cost/Performance Assumptions to Incorporate Stakeholder Feedback from 2nd Draft

Sustainable Energy Advantage, LLC

Accounting for Macro-Level Cost Pressures (1)

- Comments received from the Division of Public Utilities and Carriers (DPUC) comments suggested utilizing the lower end of the range proposed in the 1st and 2nd Draft of the 2022 Ceiling Prices, so as to limit cost to ratepayers in an environment of rising development/project costs
- Most recent (September 2021) **EIA Short-Term Energy Outlook (STEO)** forecasts sharp increase in inflation expectations from 2020 to 2022 (from 10% to 14%), a much larger increase relative to recent months

Accounting for Macro-Level Cost Pressures (2)

- Significant one-month change suggests use of a moving average would enhance robustness of estimate
- Three moving average value (containing July-September 2021 values) suggests a 12% increase (up from 10% assumed in 2nd Draft)
- **Multiple Modeling Implications (M.I.s): Utilize 12% increase as an adder to non-interconnection installed costs, which is (for Solar only), but utilize lower end of the range as suggested by DPUC (per NREL ATB 2021 "Moderate" case (see next page for more detail))**

Accounting for Macro-Level Cost Pressures (3)

Category	△ Year-on-Year (YoY) Project Cost Factor *Before* Impact of PPI (NREL ATB 2021)	△ YoY Project Cost Factor *After* Impact of PPI (2nd Draft)	△ YoY Project Cost Factor *After* Impact of PPI (Final Recommended)
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%***†

† *Value represents the "low case" result, but is higher than 2nd Draft low case result due solely to increase in forecasted 2022 average monthly PPI, reduced by the shift to the three-month moving average described on previous page.*

- **Wind and AD**
  - **12% YoY adjustment (per PPI, rather than 10% from 2nd Draft Prices) in non-interconnection installed costs (not offset by cost declines)**
- **Hydro**
  - **Given that no new estimates were received by deadline from Hydro stakeholders, set at 21% YoY adjustment (representing an average of industry stakeholder estimate and PPI, rather than 20% from 2nd Draft Prices).**

Tax Treatment for Small Solar Projects

- The DPUC argues that for Small Solar I projects, Narragansett Electric's tax policy is that REG payments are in the form of bill credits, rather than in the form of a check, which would otherwise be treated as taxable income. As a result (and per longstanding IRS guidance regarding bill credits) the credits to the residential owner should not be assumed to be taxable.
- While the consulting team is open to considering bill credits to be non-taxable (and thus excludable from the tax basis for the Ceiling Prices), there are several hurdles for considering this question during the 2022 PY Ceiling Price process, including:
  - OER suggested to the consulting team that it was their understanding that, rather than receiving either a check or a bill credit, most, if not all, customers received both for different degrees of their usage.
  - Understanding this answer would require Narragansett Electric Co. personnel to undertake an analysis of its payments to determine the proportion paid out by a check vs. conveyed via bill credit.
  - Finally, industry stakeholders have not had a chance to comment on their understanding of this question vis-à-vis their customers.
- **M.I.: The consulting team recommends considering this question during the 2023 PY Ceiling Price development process, at which time appropriate adjustments can be made following analysis by Narragansett Electric**

Property Taxation and Renewable Energy Projects

- Green Development commented that the 2022 Ceiling Prices should account for municipalities that incorporate the change in the underlying value of the land when calculating property tax inputs
- To determine municipal practices, OER and the consulting team surveyed all Rhode Island municipalities about their property valuation practices.
  - 11 responded as of this writing (October 12, 2021)
  - Only four municipalities said they would consider (but not all would commit to) increasing property taxes based on the change in the value of the land based on its use
- **M.I.: No change. The consulting team is aware of and understands the issue (that certain municipalities have implemented methodologies that would result in property taxes exceeding the $5/kW statewide value), but also does not believe a change that can affect the Ceiling Prices statewide should be undertaken unless/until a larger fraction of municipalities undertake such a change.**
  - **However, consulting team plans to re-survey municipalities during the 2023 PY Ceiling Price development process to determine if practices have sufficiently changed to justify further changes**

Post-Tariff Revenue Assumptions

- In its comments, the DPUC recommended a smaller discount to assumed post-tariff net metering revenue
- Ecogy Energy also submitted comments, citing a variety of grounds (ranging from roof warranties to their personal experience with debt financing and customer acquisition) that assuming any post-tariff revenue at all is “overblown”, and that assuming a 40% discount is “disingenuous at best” on the part of the consulting team
- Ecogy also asserted that the consulting team does not assume inverter replacement
  - NOTE: the consulting team does assume inverter replacement in Year 12, as shown in the public version of the Cost of Renewable Energy Spreadsheet Tool (CREST) shared with stakeholders this past summer.
- **M.I.: No change.**
  - **The evidence reviewed by the consulting team has consistently indicated that projects can and will operate following the 20-year contract term for non-Small Solar projects, and other developers have indicated to the consulting team that financiers have credited their projects with non-zero post-tariff revenue value.**
  - **Consulting team continues to believe (as discussed in 2nd Draft Ceiling Price PPT) the 40% discount approach balances the law (which allows for compensation at net metering rates following the tariff term), the practice of other developers, the state’s policy (of encouraging a 100% renewable energy grid by 2030), and the policy/financial uncertainty related to net metering eligibility and compensation levels.**

Other Issues from Ecogy Energy Comments

- Adoption of Zonal Incentives for REG Program
  - Ecogy suggests projects closer to load “must” be compensated for providing greater system benefit
  - **M.I.: No change. As has been communicated to stakeholders several times during this year, the Renewable Energy Growth Act only permits Narragansett Electric (and neither OER, the DG Board, nor the consulting team) to propose either zonal incentives nor public policy adders.**
- Lease Value for Medium Solar Projects
  - Ecogy also provided several additional lease agreements for Medium Solar projects in Rhode Island, suggesting that the consulting team’s change from $12,000/yr to $15,000/yr in response to other lease documents the company provided.
  - **M.I.: No change. Though the consulting team appreciates the documents provided by Ecogy, has not received other lease documents for Medium Solar projects sponsored by other developers to substantiate a larger increase, and thus plans to consider the issue further in the 2023 PY Ceiling Price process.**

Adoption of 2020 National Electrical Code

- The consulting team sought comment no later than October 11 re: 2020 NEC adoption (effective in early 2022) compliance costs that could result in changes to the Ceiling Prices
- No comments were received from stakeholders by the deadline
- **M.I.: No change to inputs related to NEC compliance**

Disclaimer RE: Potential for Adoption of Build Better Act/Other Changes to Federal Policy

- The consulting team is closely tracking the Build Back Better Act, the budget reconciliation bill in Congress widely expected to (if enacted) provide long-term extensions (and potential changes in eligibility criteria for) various types of renewable energy tax credits, as well as new provisions providing grants in lieu of tax credits (known as “direct pay”) that could have very significant impacts on the assumed Ceiling Prices.
- While the consulting team assesses that passage of such potential tax credit changes is more likely, it is unclear at this point if and/or when such changes might be enacted into law.
- **M.I.: No changes at this time.**

Appendix B: Revised Modeling Parameters

Sustainable Energy Advantage, LLC

Summary: Cost & Production Assumptions (Solar)

	Small I	Small II	Medium I	Medium II	Comm'l I	Comm'l I (CRDG)	Comm'l II	Comm'l II (CRDG)	Large	Large CRDG
Nameplate Capacity (kW)	5.8 [5]	25	150	250	500	500	1,000 [900]	1,000 [900]	5,000 [4,500]	5,000 [4,500]
Capacity Factor	13.4% [14.0%]	13.4% [14.0%]	14.5%	14.5%	14.6%	14.6%	14.6%	14.6%	15.10%	15.10%
Annual Degradation	1.0% [0.5%]	1.0% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.8% [0.5%]	0.5%	0.5%
Useful Life (Years)	25	25	25 [20]	25 [20]	25 [20]	25 [20]	25 [20]	25 [20]	30 [25] [20]	30 [25] [20]
Total Capital Cost ^ ($/kW)	$3,377 [$3,310] [$3,195] [$3,146]	$3,103 [$3,042] [$2,935] [$2,883]	$2,792 [$2,739] [N/A] [N/A]	$2,408 [$2,361] [$2,211] [$2,332]	$2,108 [$2,068] [$1,936] [$2,097]	$2,208 [$2,168] [$2,036*] [$2,247*]	$1,938 [$1,901] [$1,780] [$1,869]	$2,038 [$2,001] [$1,880*] [$2,019*]	$1,444 [$1,411] [$1,313] [$1,492]	$1,544 [$1,511] [$1,413*] [$1,642*]
Fixed O&M ($/kW-yr)	$29 [$35]	$24 [$35]	$14.57	$14.57	$12.03	$34.03 [$37.03]	$12.03	$34.03 [$37.03]	$8.00 [$12.03]	$30.00 [$37.03]
O&M Escalation Factor	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.34% [0.27%]	0.34% [0.27%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]	0.57% [0.45%]
Project Management ($/yr)	$0	$0	$3,000	$3,000	$4,000	$4,000	$4,000	$4,000	$20,000 [$12,000]	$20,000 [$12,000]
Site Lease ($/yr)	$0	$0	$7,500 [$12,000]	$15,000 [$12,000]	$20,000	$20,000	$20,000	$20,000	$67,500 [$50,000]	$67,500 [$50,000]

Values in [Blue Brackets] represent 2021 ceiling price inputs, [Green Brackets] represent Draft 1 inputs that were revised for Draft 2, [Purple Brackets] represents Draft 2 inputs that were revised for the final recommended prices. * Reflects installed cost of non-CRDG project from same category, plus estimated cost of customer acquisition ($100/kW, previously $150/kW)
^ Total cost includes interconnection cost

Summary: Cost & Production Assumptions
Wind, Hydro, and AD

	Wind	Large Wind - CRDG	Hydroelectric	Anaerobic Digestion
Nameplate Capacity (kW)	3,000	3,000	500	725
Capacity Factor	21.00%	21.00%	55.00%	92%[1]
Annual Degradation	0.5%	0.5%	0.0%	0.0%
Total Cost ($/kW)	$3,158 [$3,102] [$2,820]	$3,258 [$3,202] [$2,970]	$11,918 [$11,824] [$9,931]	$11,200 [$11,150] [$10,150]
Fixed O&M ($/kW-yr)	$26.50	$48.50 [$51.50]	$2.00	$600
O&M Inflation	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.29% [0.20%]	0.29% [0.20%]	4.0% [2.7%]	1.5% [1.0%]
Project Management ($/yr)	$18,000	$18,000	$3,000	$75,000
Site Lease ($/yr)	$162,000	$162,000	$8,750	$35,000

1. *Note: For Anaerobic Digestion we use an Availability Factor*

Values in [Blue Brackets] represent 2021 ceiling price inputs, [Green Brackets] represent Draft 1 inputs that were revised for Draft 2, [Purple Brackets] represents Draft 2 inputs that were revised for Draft 3.

Summary: Financing Assumptions (Small Solar)

	Small I		Small II	
	2021 Final	***2022 1st Draft, 2nd Draft & Final Recommended***	***2021 Final***	***2022 1st Draft, 2nd Draft & Final Recommended***
Federal Investment Tax Credit (%)	26%	**26%**	26%	**26%**
% Debt	71%	**60%**	60%	**50%**
Debt Term (years)	13	**13**	10	**10**
Interest Rate on Term Debt	6.3%	**6.3%**	7.0%	**7.0%**
Lender's Fee (% of total borrowing)	4.25%	**4.25%**	2.3%	**2.3%**
Target After-Tax Equity IRR	5.2%	**7%**	13.0%	**12.5%**

Summary: Financing Assumptions (Solar >25 kW)

	Medium		Comm'l & Comm'l CRDG		Large & Large CRDG	
Assumption Set	***2021 Final***	***2022 1st Draft, 2nd Draft & Final Recommended***	***2021 Final***	***2022 1st Draft, 2nd Draft & Final Recommended***	***2021 Final***	***2022 1st Draft, 2nd Draft and Final Recommended***
Federal Investment Tax Credit (%)	26%	**26%**	26%	**26%**	26%	**26%**
% Debt	55%	**55%**	55%	**55%**	55%	**53%**
Debt Term (years)	15	**15**	15	**15**	15	**15**
Interest Rate on Term Debt	6.0%	**6.6%**	5.25%	**5.85%**	5.25%	**5.85%**
Lender's Fee (% of total borrowing)	1.0%	**1.0%**	1.0%	**1.0%**	2.0%	**2.0%**
% Equity Share of Sponsor Equity	25%	**25%**	25%	**25%**	25%	**25%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	13.5%	**13.0%**	12.5%	**12.0%**	11.5%	**11.0%**
% Equity Share of Tax Equity	75%	**75%**	75%	**75%**	75%	**75%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	**9.5%**	9.5%	**9.5%**	9.5%	**9.5%**
Depreciation Approach	5-Year MACRS	**5-Year MACRS**	5-Year MACRS	**5-Year MACRS**	5-Year MACRS	**5-Year MACRS**

Summary: Financing Assumptions (Non-Solar)

	Wind & Wind CRDG		Hydroelectric		Anaerobic Digestion	
Assumption Set	***2021 Final***	***2022 1st Draft, 2nd Draft & Final Recommended***	***2021 Final***	***2022 1st Draft, 2nd Draft & Final Recommended***	***2021 Final***	***2022 1st Draft, 2nd Draft & Final Recommended***
Federal Investment Tax Credit	18%	**0% (Expiring 1/1/2022)**	0% (Available but not Monetizable)	**0% (Expiring 1/1/2022)**	30%	**None (Expiring 1/1/2021)**
% Debt	60%	**60%**	70%	**70%**	45%	**45%**
Debt Term (years)	15	**15**	20	**20**	15	**15**
Interest Rate on Term Debt	6.0%	**6.6%**	6.25%	**7.15%**	6.25%	**6.85%**
Lender's Fee (% of total borrowing)	1.0%	**1.0%**	1.88%	**1.88%**	1.5%	**1.5%**
% Equity Share of Sponsor Equity	25%	**60%**	100%	**80%**	20%	**60%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	12.5%	**12.0%**	12.5%	**12.0%**	12.5%	**12.0%**
% Equity Share of Tax Equity	75%	**40%**	0%	**20%**	0%	**40%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.0%	**9.5%**	9.0%	**9.5%**	9.0%	**9.5%**
Depreciation	5-Year MACRS	**Average of 100% bonus and 5-Year MACRS**	7-year MACRS	**7-year MACRS**	5-year MACRS	**5-year MACRS**

Appendix C: Stakeholder Engagement Details

Sustainable Energy Advantage, LLC

2022 PY Ceiling Price Stakeholder Engagement to Date (1)

- The PUC approved the consulting team's budget for 2022 Program Year (PY) support in late April 2021 in Docket 4604
- The consulting team emailed stakeholders on June 2, 2021 with Data Request and Survey, requested responses by June 28
  - Received responses from 14 Solar, 1 Non-Solar and 2 combination Solar/Non-Solar stakeholders.
- Circulated 1st Draft Proposed 2022 Ceiling Prices and Overview of Potential Options Related to Solar Performance Assumptions and Solar Renewable Energy Class Subdivisions on July 13, 2021, ahead of meeting on July 27. Requested comments no later than August 20
  - Included options for technology categories, system size bins, and modeled system size, as well as the proposed Ceiling Prices and responses to stakeholder input.
  - Meeting attended by over a dozen stakeholders, including a broad array of Solar and Non-Solar developers, as well as the Division of Public Utilities and Carriers (DPUC) and National Grid.
  - Received responsive comments from 8 stakeholders – 5 Solar stakeholders, 1 Non-Solar stakeholder and 2 Solar/Non-Solar stakeholders, as well as the DPUC

2022 PY Ceiling Price Stakeholder Engagement to Date (2)

- Requested comments on issued public versions of the Cost of Renewable Energy Spreadsheet Tool (CREST) utilized to calculate the Ceiling Prices on August 9, 2021
- Circulated 2nd Draft Proposed 2022 Ceiling Prices on September 2, 2021 ahead of meeting on September 8, 2021. Requested comments on the prices no later than September 30
  - Meeting attended by 35 stakeholders, including a broad array of Solar and Non-Solar developers, as well as the DPUC
  - Received responsive comments from 2 stakeholders – the DPUC and 1 Solar and Non-Solar stakeholder
- Requested supplemental comment on impacts of adoption of electrical code changes by October 11, 2021
  - No responsive comments received

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Rhode Island Distributed Generation Board

SURVEY TO INFORM 2022 CEILING PRICE DEVELOPMENT

DUE DATE: Friday, August 20, 2021

Dear Renewable Energy Industry Participants:

The Rhode Island Office of Energy Resources and Distributed Generation Board seek your input into the development of ceiling prices for renewable energy projects under the Renewable Energy Growth (REG) Program for the 2022 Program Year. OER and the DG Board have an obligation to submit ceiling price recommendations to the RI Public Utilities Commission intended to support viable and cost-effective projects. Receiving current information from market participants is critical to developing robust, accurate, and defensible ceiling price recommendations.

Given the unprecedented environment due to COVID-19, as well as the natural evolution of market conditions and the experience with the DG Standard Contracts (SC) and REG programs to date, the DG Board and OER seek your feedback on several topics related to Ceiling Price development for the 2022 Program Year (beginning April 1, 2022). OER requests descriptive explanations and source materials to complement the quantitative data provided in response to the Data Request.

Feel free to respond to as many of the following questions as you are able. Please be specific with your comments, recommendations and sources. Use as much room as you need. You may also save your responses and come back to complete the survey at a later time if you are interrupted.

This survey is your primary opportunity to provide written comments and recommendations, as well as evidence to substantiate your comments and recommendations. Additional opportunities will also exist for both written comments and participation in public meetings. In general, the absence of a response to any of these questions will be treated as support for the current policy design.

As has been the case in prior years, the 2022 Ceiling Prices must ultimately be approved by the Rhode Island Public Utilities Commission (PUC) after thorough review and comment by the Commissioners, Commission staff and the Division of Public Utilities and Carriers, Rhode Island's official advocate for electric ratepayers. In anticipation of this review, we note that it is highly unlikely that we would incorporate suggested changes to the recommended Ceiling Prices that are not supported by substantial and credible evidence, or could be inconsistent with state laws, rules and tariffs governing the REG Program already approved by the General Assembly and/or the PUC. While we welcome the opportunity to receive and vet all stakeholder feedback, our flexibility in incorporating said stakeholder feedback is not absolute.

All Survey responses are voluntary and will be kept confidential in accordance with the State's Access to Public Record Act. Any information provided in response to this Survey will not be identified in relation to, or attributed to, an individual respondent in any public presentation or public document.

If you have any questions about how to complete this survey, please contact Jim Kennerly at jkennerly@seadvantage.com or (508) 665-5862 and/or Toby Armstrong at tarmstrong@seadvantage.com or (508) 665-5864.

Respondent Information

* 1. Please provide your name and contact information:

Name

Company

Email Address

Phone Number

2. How do you expect COVID to impact projects proposed in Program Year 2022, as well as related supply chains? Please describe in detail and substantiate with documentation to Jim Kennerly at jkennerly@seadvantage.com and Toby Armstrong at tarmstrong@seadvantage.com.

3. What types of projects are you involved with? You may add multiple responses.

- [ ] Small Solar (under 25 kW)
- [ ] Medium, Commercial and/or Large Solar (>25 kW-5,000 kW)
- [ ] Non-Solar (Wind, Hydroelectric, Anaerobic Digestion)

4. In past years of the REG Ceiling Price analysis, the Total Installed Capital Cost estimates have been based on quartiles and averages obtained from databases of projects participating in state programs in MA, CT, NY, and quotes from EnergySage. However, MA now only publishes data associated with completed projects, which only allows for use of such data for projects less than or equal to 25 kW. Is there any reason for the consulting team not to use other available state data sources in Program Year 2022?

If so, please provide documentary data and evidence to substantiate your claim to Jim Kennerly at jkennerly@seadvantage.com and Toby Armstrong at tarmstrong@seadvantage.com.

Small Solar Screening Question

5. Are you involved with Small Solar (under 25 kW)?

- ◯ Yes
- ◯ No (skip this section)

Small Solar (under 25 kW) Questions

6. The table below contains the current 2022 Ceiling Price analysis financing assumptions for Small Solar projects.

NOTE #1: The after-tax equity IRRs shown above reflect a levered value (i.e., the project's net return after paying its debt obligations), to ensure consistency with the inputs to the Cost of Renewable Energy Spreadsheet Tool (CREST) model used to calculate the Ceiling Prices.

NOTE #2: These values are subject to change based on further evidence, research, analysis and stakeholder feedback.

If you believe any of the above inputs should be changed, please enter in your recommended input into the boxes below. For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be revised, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

Small I - % Debt	
Small I - Debt Term	
Small I - Interest Rate on Term Debt	
Small I - Lender's Fee	
Small I - Target After-Tax Equity IRR	
Small II - % Debt	
Small II - Debt Term	
Small II - Interest Rate on Term Debt	
Small II - Lender's Fee	
Small II - Target After-Tax Equity IRR	

7. The table below contains the 2022 Ceiling Price analysis production and cost assumptions for Small Solar projects.

If you believe any of the above inputs should be changed, please enter in your recommended input into the boxes below. **Please specify if the change would apply to Small Solar I, II, or both.** For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you disagree with, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

Any responses that are not provided in units consistent with units utilized the table above will not be accepted.

Fixed O&M

O&M Escalation Factor

Non-O&M Escalation Factor (e.g., site lease, insurance, project mgmt, etc)

Insurance (% of cost)

Project mgmt ($/yr)

Site Lease ($/yr)

8. In your experience, what is the market share (% of total) in Rhode Island of customers financing a 1-15 kW system purchase with:

Home equity loans/lines of credit

Specially-designed solar loans

Cash

Other debt (please specify)

9. What is the typical duration (in years) of home equity loans in Rhode Island for systems 1-15 kW?

10. What is the typical duration (in years) of solar loans in Rhode Island for systems 1-15 kW?

11. What are the typical interest rates (in percentage terms) for home equity loans in Rhode Island for systems 1-15 kW?

12. What are typical interest rates for solar loans in Rhode Island for systems 1-15 kW?

13. What are the total fees (expressed as a percentage of the total loan amount) typically charged by the lender to a solar PV system 1-15 kW?

14. Are lender fees usually accounted for separately from the loan principal, or are they rolled into the principal itself?

- Accounted For Separately
- Rolled into Principal
- Other (please specify)

15. What percentage of projects from 15-25 kW are:

Purchased 100% with cash

Financed 100% with debt

A mix of cash and debt

16. For customers utilizing a mix of cash and debt, what percentage of cash is typical?

17. What kind of debt do 15-25 kW projects usually utilize? What are typical durations (in years), interest rates, and fees associated with this debt?

Type of debt:

Typical Duration:

Typical Interest Rates:

Fees:

18. We currently assume year-over-year capital cost declines of 3.5% for Small Solar I and Small Solar II. Do you agree or disagree with the cost decline assumptions? (Note that the consulting team is not considering eliminating any cost decline assumption, but rather seeking feedback on the magnitude of the expected decline.)

If you disagree, please specify a more reasonable assumption to expect for changes in capital equipment costs from 2021 to 2022? What is your basis and evidence for that expectation? Submit all relevant documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

- Agree
- Disagree (please specify)

19. Do you assume the eventual installation of paired energy storage prior to the end of your project's useful life?

- Yes
- No

20. **(if yes to storage)** How would you size said energy storage project (in terms of rated power and hours of discharge)?

21. **(if yes to storage)** What year (1-25) do you assume it will be installed?

22. **(if yes to storage)** How much (in $/kWDC of the solar facility) do you assign as the upfront capital cost of the installation?

23. **(if yes to storage)** How much (in terms of $/kW-yr of the solar facility) do you assign as the ongoing operating costs of the installation?

24. **(if yes to storage)** Please describe your operating life assumption (in years) for the paired energy storage project.

25. **(if yes to storage)** Please describe how much (in $/kWh and/or $/kW, as may be necessary) you assume in terms of post-tariff revenue as a result of installing energy storage.

Solar >25 kW Screening Question

26. Are you involved with solar over 25 kW?

- ◯ Yes
- ◯ No (skip section)

Solar Projects Greater than or Equal to 25 kW: Capital Cost, Operating Cost & Financing Assumptions

27. Copied below are the solar cost and production modeling inputs used in the approved 2021 Ceiling Prices calculations for Solar projects. Please reference the table as you answer the questions below.

O&M costs should reflect all fixed and variable expenses associated with project operations, EXCEPT annual expenses for insurance, property taxes, land leases, royalties, and project management.

If you believe any of the aforementioned inputs should be changed, please enter in your recommended input into the boxes below. **For each recommended change, note which project categories (e.g., Medium) the change should apply to.** For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be changed, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com (such as a properly-redacted quote or contract for O&M services).

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

Fixed O&M	
O&M Escalation Factor	
Non-O&M Operating Expense (e.g., insurance, project mgmt, land lease etc) Escalation Factor	
Insurance	
Project Management	
Site Lease	

28. The table below shows our proposed 2022 RI REG financing assumptions for Solar projects.

NOTE #1: The after-tax equity IRRs shown above reflect a levered value (i.e., the project's net return after paying its debt obligations), in order to ensure fidelity with the inputs to the Cost of Renewable Energy Spreadsheet Tool (CREST) model used to calculate the Ceiling Prices.

NOTE #2: These values are subject to change based on further evidence, research, analysis and stakeholder feedback.

Are there any proposed 2022 Solar REG assumptions that you find to be outside the normal range? If so, please identify them and propose an alternative assumption. **For each recommendation, state which category of projects (e.g., Medium) it should apply to.**

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

% Debt	
Debt Term (years)	
Interest Rate on Term Debt	
Lender's Fee (% of total borrowing)	
% Equity Share of Sponsor Equity	
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	
% Equity Share of Tax Equity	
Target After-Tax Equity IRR (Tax Equity, Levered Return)	
Depreciation Approach	

29. For Solar projects, we currently assume that only the most creditworthy borrowers are eligible for loan terms beyond 15 years, and therefore modeling a loan term over 15 years would not accurately reflect a value that is appropriate to the market as a whole. Do you agree or disagree with this assumption?

If you do not agree, please explain what debt term we should assume instead as a reasonable proxy for the market as a whole.

- Agree
- Disagree (please specify)

30. We currently assume year-over-year capital cost declines 4.5% for all solar categories over 25 kW. Do you agree or disagree with the cost decline assumptions? (Note that the consulting team is not considering eliminating any cost decline assumption, but rather seeking feedback on the magnitude of the expected decline.)

If you disagree, please specify a more reasonable non-zero assumption to expect for changes in capital equipment costs from 2021 to 2022? What is your basis and evidence for that expectation? Submit all relevant documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

- Agree
- Disagree (please specify)

31. We currently assume (based on previous market participant feedback) that competition and market conditions have applied downward pressure to sponsor equity returns for Solar projects in recent years, and that these conditions have (and will continue) to assert themselves as the COVID-19 pandemic subsides. If you do not agree with this assumption, please compare sponsor equity target returns between 2020 and 2021 with expected sponsor equity target returns for Program Year 2022 and provide the source or other basis for your comparison.

32. We also currently assume (based on previous market participant feedback) that tax equity investors in Solar projects continue to lack the tax capacity to elect 100% bonus depreciation and continue to utilize the five-year schedule of the Modified Accelerated Cost Recovery System (MACRS) for depreciation. Would you agree with this assumption? Why or why not? If you do not agree, please explain what we should assume instead.

33. What percentage of projects that you encounter have investors that are not able to fully leverage both 5-year MACRS and the federal Investment Tax Credit (ITC) in the year that said benefits are generated?

5-year MACRS

ITC

Questions Regarding Returns to Scale for Solar Projects >25 kW

34. It is well known that as the system scale of a solar PV project increases, the unit costs decline with increasing returns to scale. In the text boxes below, please note **the point(s) within between 25 kW and 5000 kW** that capital and operating costs begin to drop (on a unit basis) resulting from increasing returns to project scale. Please notes as many points as you feel accurately reflects inflection points for project economics, but no more than five for each cost category (Please also note, as applicable, if any of these costs do not substantially decline with increased system scale within this size range).

Upfront Capital Costs - Inflection point 1

Upfront Capital Costs - Inflection point 2

Upfront Capital Costs - Inflection point 3

Upfront Capital Costs - Inflection point 4

Upfront Capital Costs - Inflection point 5

Non-Capital Operating Costs - Inflection point 1

Non-Capital Operating Costs - Inflection point 2

Non-Capital Operating Costs - Inflection point 3

Non-Capital Operating Costs - Inflection point 4

Non-Capital Operating Costs - Inflection point 5

Solar Projects Greater than or Equal to 25 kW: Post-Tariff Assumptions

35. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, what do you see as your principal sources of revenue following the expiration of the term of your REG tariff term? Note, under current law, Net Metering is not available for projects participating in the REG program. Please indicate how much, in $/MWh, you expect to receive (and include in your pro forma) from these sources of revenue from the end of the tariff term until the end of the project's expected useful life.

Capacity ($/MWh)

RECs ($/MWh)

Energy ($/MWh)

Ancillary Serv. ($/MWh)

Other - please specify ($/MWh)

36. Do you assume the eventual installation of paired energy storage prior to the end of your project's useful life?

- Yes
- No

37. **(if yes to storage)** How would you size said energy storage project (in terms of rated power and hours of discharge)?

38. **(if yes to storage)** What year (1-25) do you assume it will be installed?

39. **(if yes to storage)** How much (in $/kWDC of the solar facility) do you assign as the upfront capital cost of the installation?

40. **(if yes to storage)** How much (in terms of $/kW-yr of the solar facility) do you assign as the ongoing operating costs of the installation?

41. **(if yes to storage)** Please describe your operating life assumption (in years) for the paired energy storage project.

42. **(if yes to storage)** Please describe how much (in $/kWh and/or $/kW, as may be necessary) you assume in terms of post-tariff revenue as a result of installing energy storage.

43. When sizing the inverter for projects you submit into the REG program, what DC-AC ratio range do you typically employ? Please explain your reasoning for this DC-AC sizing ratio.

Medium Solar (25-250 kW)	
Commercial Solar (251-999 kW)	
Large Solar (1-5 MW)	

44. Do you plan to replace your project's inverter?

- ○ Yes
- ○ No

45. **(if yes to inverter replacement)** Please indicate the year in which you assume that you will replace your project's inverter (e.g., year 10)

46. **(if yes to inverter replacement)** Would you consider replacing the project's inverter with a smaller inverter?

- ○ Yes
- ○ No

47. **(if yes to inverter replacement)** To what DC-AC ratio would you consider sizing your inverter to, upon replacement of the inverter? Please explain your reasoning for over-sizing the project's output to its inverter.

Medium (25-250 kW)	
Commercial (251-999 kW)	
Large (1-5 MW)	

48. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, how long (in years) do you assume projects will operate prior to their decommissioning?

49. Do you assume replacement of some or all the project's generation equipment?

- Yes
- No

50. **(if yes to equip. replacement)** What percentage of the project's generation capacity would you assume that you will replace?

51. **(if yes to equip. replacement)** Please provide your estimate of the useful life of this repowered equipment, as well as the change in capacity factor that the replacement equipment will provide (e.g., will change solar panels after 20 years, and expect to increase DC capacity factor from 12% in year 20 to 15% in year 21)

Useful life (in years)

Change in Capacity Factor

Non-Solar Screening Question

52. Are you involved with non-solar projects (Hydro, Wind, AD)

- ◯ Yes
- ◯ No (skip section)

Non-Solar (Hydro, Wind, AD)

53. Copied below are the non-solar cost and production modeling inputs used in the approved 2021 Ceiling Prices calculations for Wind, Hydroelectric, and Anaerobic Digestion projects. Please reference the table as you answer the questions below.

If you believe any of the aforementioned inputs should be changed, please enter in your recommended input into the boxes below. **For each recommended change, note which project categories (e.g., Hydro) the change should apply to.** For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be changed, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com (such as a properly-redacted quote or contract for O&M services).

Note that we are not asking for feedback on total cost inputs, as they are derived from an analysis of recent installed cost data.

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

Nameplate Capacity (e.g., typical sized project modeled for the category)	
Capacity Factor	
Annual Degradation	
Fixed O&M	
O&M Inflation	
Insurance	
Project Management	
Site Lease	

54. The table below shows our proposed 2022 RI REG financing assumptions for Non-Solar projects.

If you believe any of the aforementioned inputs should be changed, please enter in your recommended input into the boxes below. For each recommended change, note which project categories (e.g., Hydro) the change should apply to. For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be changed, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com (such as a properly-redacted quote or contract for O&M services).

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

% Debt

Debt Term (years)

Interest Rate on Term Debt

Lender's Fee (% of total borrowing)

% Equity Share of Sponsor Equity

Target After-Tax Equity IRR (Sponsor Equity, Levered Return)

% Equity Share of Tax Equity

Target After-Tax Equity IRR (Tax Equity, Levered Return)

Depreciation Approach

55. For Non-Solar projects, we currently assume that only the most creditworthy borrowers are eligible for loan terms beyond 15 years, and therefore modeling a loan term over 15 years would not accurately reflect a value that is appropriate to the market as a whole. Do you agree or disagree with this assumption?

If you do not agree, please explain what debt term we should assume instead as a reasonable proxy for the market as a whole.

- Agree
- Disagree (please specify)

56. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, how long do you assume projects will operate prior to their decommissioning?

57. Do you assume replacement of some or all the project’s generation equipment?

- Yes
- No

58. **(if yes to equip. replacement)** What percentage of the project’s generation capacity would you assume that you will replace?

59. **(if yes to equip. replacement)** Please provide your estimate of the useful life of this repowered equipment, as well as the change in capacity factor that the replacement equipment will provide (e.g., will change solar panels after 20 years, and expect to increase DC capacity factor from 12% in year 20 to 15% in year 21)

Useful life (in years)	
Change in capacity factor	

60. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, what do you see as your principal sources of revenue following the expiration of the term of your REG tariff term?

Note, under current law, Net Metering is not available for projects participating in the REG program.

Please indicate how much, in cents/kWh, you expect to receive (and include in your pro forma) from these sources of revenue from the end of the tariff term until the end of the project’s expected useful life.

Capacity ($/MWh)	
RECs ($/MWh)	
Energy ($/MWh)	
Ancillary Serv. ($/MWh)	
Other ($/MWh)	

61. Do you assume the eventual installation of paired energy storage (e.g. to participate in organized markets following the expiration of your initial tariff term or for other reasons)?

- Yes
- No

62. **(if yes to storage)** How would you size said energy storage project (in terms of rated power and hours of discharge)?

63. **(if yes to storage)** What year (1-25) do you assume it will be installed?

64. **(if yes to storage)** How much ($/kWDC of the generation facility) do you assign as the upfront capital cost of the installation?

65. **(if yes to storage)** Please describe how much (in $/kWh and/or $/kW, as may be necessary) you assume in terms of post-tariff revenue as a result of installing energy storage.

CRDG Screening Question

66. Is your firm actively engaged in developing Community Remote Distributed Generation (CRDG) projects into forthcoming Rhode Island Renewable Energy Growth program Open Enrollments?

- ◯ Yes
- ◯ No (skip section)

Community Remote Distributed Generation (CRDG)

67. Do you use a 3rd party to enroll customers? If so, please describe your relationship with this third party. If not, please simply write “No” or “N/A”.

68. Does your firm target residential customers to be offtakers of your CRDG projects?

- Yes
- No

69. **(if yes to resi. offtake)** Do you specifically target or market to customers on National Grid’s income-qualified (A-60) rate class? Why or why not?

70. **(if yes to resi. offtake)** Would your answer to the previous question change if National Grid were to become the central entity for enrolling income qualified customers on the A-60 rate schedule? Why or why not?

71. Does your firm target Commercial customers to be offtakers of your CRDG projects?

- Yes
- No

72. **(if yes to comm. offtake)** Please describe how your firm (or a 3rd party) targets such customers.

73. Does your firm aim to recruit "anchor tenant" customers that contract for a large share of the project's offtake? If so, please explain why you utilize this approach.

74. **(if yes to "anchor tenant")** Please explain the impact an anchor tenant has on the project in comparison to one in which the project's offtake is assigned entirely to residential customers.

75. In a hypothetical scenario in which National Grid were to become the central entity for enrolling some or all the CRDG customers, would your firm change the way in which it approaches the CRDG market? Why or why not?

76. Would requiring National Grid to be the central entity for enrolling some or all CRDG customers affect any existing, expected or potential contractual or other long-standing business arrangements? Why or why not?

77. Please explain any other ways in which making National Grid the central entity for enrolling some or all CRDG customers would affect your business and/or your participation in the CRDG market segment.

Additional Questions Regarding Community Remote Distributed Generation (CRDG)

Preamble: Under the Renewable Energy Growth Act, the Ceiling Prices for CRDG projects (to which capacity allocations are extended to Commercial Solar, Large Solar, and Wind projects) cannot be more than 15% higher than for similarly situated non-CRDG renewable energy classes. In simple terms, the categories of cost can be separated into upfront customer acquisition costs (functionally, a capital cost incurred prior to year 1) and ongoing customer management and care (functionally, an operating expense incurred from Year 1 to the end of the project's life). It is our team's understanding, based on market participant information, that upfront customer acquisition costs average to approximately $100/kWDC while the cost of ongoing customer management and care is $22/kWDC-yr.

78. Do you believe the assumptions of $100/kWDC for upfront customer acquisition is accurate for Commercial Solar CRDG projects (ranging from 251-999 kW DC)?

- Yes
- N/A (not a solar developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

79. Do you believe the assumptions of $22/kWDC-yr for ongoing customer management and care is accurate for Commercial Solar CRDG projects (ranging from 251-999 kW DC)?

- Yes
- N/A (not a solar developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

80. Do you believe the assumption of $100/kW DC for upfront customer acquisition is accurate for Large Solar CRDG projects (ranging from 1-5 MW DC)?

- Yes
- N/A (not a solar developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

81. Do you believe the assumption of $22/kWDC-yr for ongoing customer management and care is accurate for Large Solar CRDG projects (ranging from 1-5 MW DC)?

- Yes
- N/A (not a solar developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

82. Do you believe the assumption of $100/kW DC for upfront customer acquisition is accurate for Wind CRDG projects (ranging from 0-5 MW DC)?

- Yes
- N/A (not a wind developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

83. Do you believe the assumption of $22/kW-yr for ongoing customer management and care is accurate for Wind CRDG projects (ranging from 0-5 MW DC)?

- Yes
- N/A (not a wind developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

Community Remote Distributed Generation (CRDG)

84. In a hypothetical scenario in which National Grid were to become the central entity for enrolling some or all CRDG customers, would this cause you to consider participating in the CRDG program? Why or why not?

NOTE REGARDING SURVEY RESPONSES

The purpose of this survey (which was designed by Sustainable Energy Advantage, LLC (SEA), as a contractor to the Rhode Island Office of Energy Resources) is to objectively determine the approach that municipal assessors utilize in valuing renewable energy projects for the purposes of property taxation, and to be able to characterize the geographic dispersion of these approaches across Rhode Island.

To ensure candid responses, the information provided in this form will only be provided to SEA (and stored on SEA servers) for the purposes of developing Ceiling Prices for the Renewable Energy Growth program for the 2022 Program Year. Your individual responses will thus be shielded from public disclosure (including disclosure to OER) under Rhode Island law.

* 1. Please enter your name, the municipality you work for, your work email address and work phone number.

Name

City/Town

State/Province

Email Address

Phone Number

2. Are there any commercial-scale renewable energy projects (i.e., larger projects not located on private residential property) located in your municipality?

Please answer yes or no in the box below, and elaborate on the types of renewable energy projects (e.g. solar, wind, hydroelectric) in your town that are either under development or fully-developed.

3. Current regulations issued by the Rhode Island Office of Energy Resources (OER) set a $5/kW tangible tax value for renewable energy property in Rhode Island. Do you consider any other inputs associated with the project or the underlying land when valuing such projects for the purposes of collecting property taxes?

4. Does your municipality's valuation/assessment approach differ depending upon which renewable energy technology (e.g. solar, wind, hydroelectric) is being utilized?

If so, please explain how your municipality's approach varies by technology.

5. Please describe any other methodological approaches your municipality uses in valuing renewable energy projects for the purpose of collecting property taxes.

Solar Capacity Factor Research and Recommendation

Rhode Island DG Board Meeting
March 30, 2021

nationalgrid

Why did we do this study?

Capacity factor is a percent number that the peak AC value of a electric generator is generating over the course of a year.

In RE Growth and Net Metering, DG resource size in RI is limited to produce the annual historic average usage of the customer.

Capacity factor is used to determine system size, and concern had been raised that the standardized use of 14% DC-to-AC does not allow some customers to size DG systems to their historic usage. The standard formula is:

Usage (kWh) / Capacity Factor / 8760 = System Size (kW-dc)

Key Findings

- **The use of a calculator like PV Watts does provide more customized CF results, as expected.**
- **The average of the sample in PV Watts using project specific inputs resulted in an average CF essentially the same as 14%.**
- **Both the standard 14% and PV Watts, however, overestimate the production of systems compared to actual meter readings.**
- **National Grid is exploring the use of a table based on actual averages and PV Watts guidance to capture angle and azimuth variation of output, once implemented.**

Study Details

- Compared PV Watts estimates with NG Estimated Generation and actual generation reads for 303 roof mounted RE Growth projects <25 kW
- PV Watts Inputs: Tilt, Azimuth, DC-AC Ratio, type = roof mounted
- NG Estimate pulled from GridForce, actuals from billing system
- 95% confidence interval with a 5.4% +/- margin of error based on sample size
    - With an average capacity factor of 12.78%, this means we can be 95% sure that the actual number is between 12.09% and 13.47%.

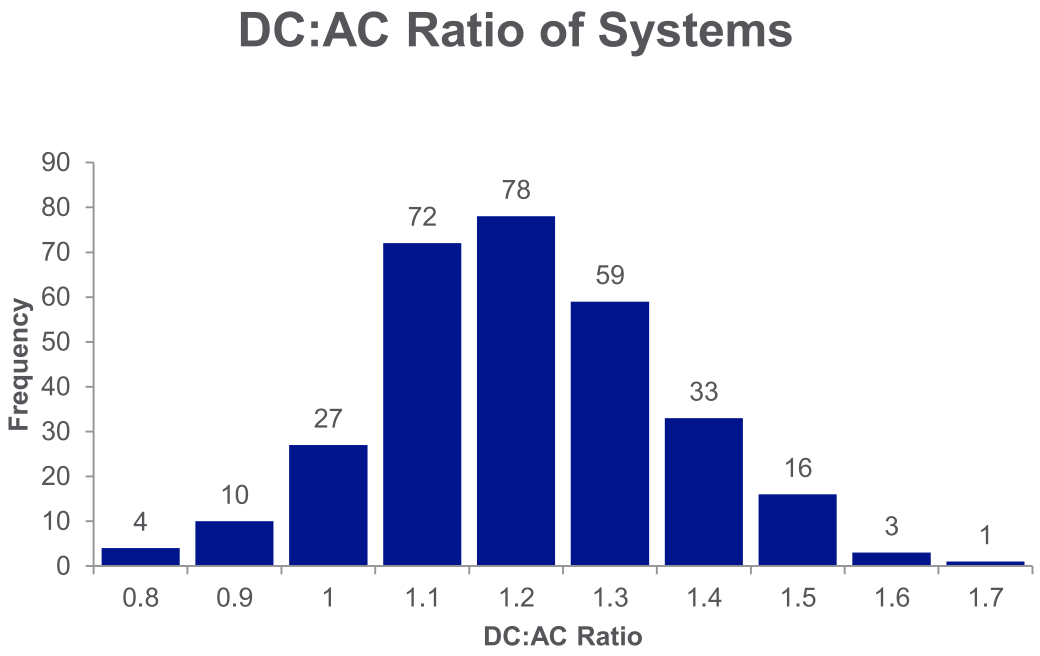
Sample Angle and Azimuth of Arrays

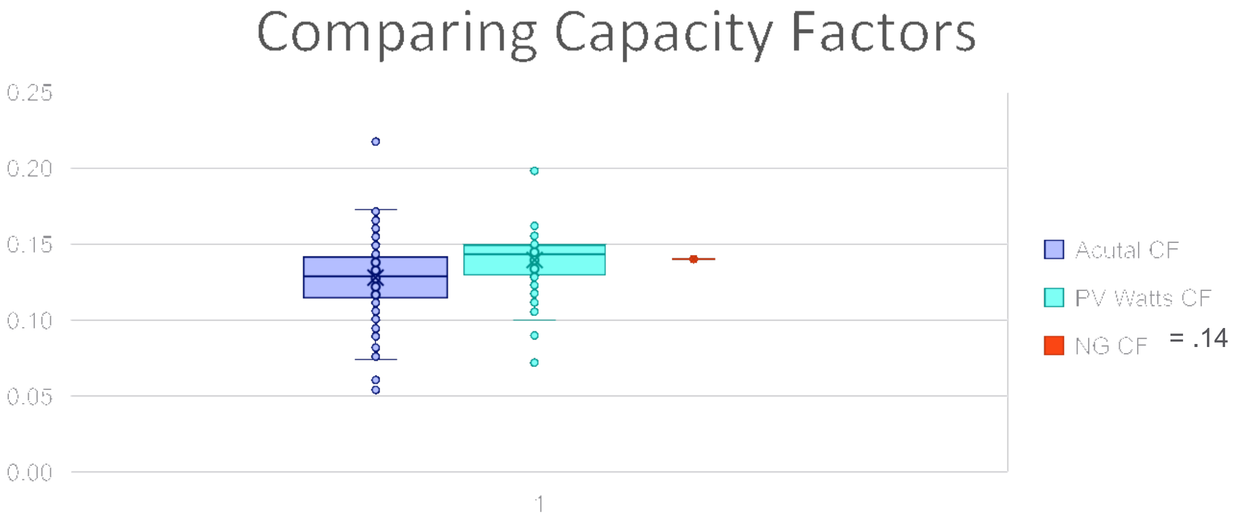
- **65% of systems fall between 120 and 239 degrees, southerly**
  - 25% of sample systems at 180˚
- **Optimal tilt is ~41.45 +/-15 depending on the season**
- **72% of sample systems fall in the ideal range for RI**
- **Table: Darker green = higher count of systems meeting these conditions**

Count of Input Ranges	Tilt				
Azimuth	0-9'	10-19'	20-29'	30-39'	40-50'
0-39		1			1
40-79		1	3	1	
80-119	2	3	26	4	6
120-159		6	13	12	3
160-199	2	17	59	34	13
200-239	1	7	15	9	6
240-279		10	20	17	7
280-319		1	2		
320-360					1

DC:AC Ratio

- **49% of projects have DC:AC ratios between 1.1 and 1.2**
- **13% systems with a ratio less than 1**
- **7% systems with a ratio greater than 1.5**
- **Higher ratio systems can produce more kWh per $ of installed cost, but have lower capacity factors**



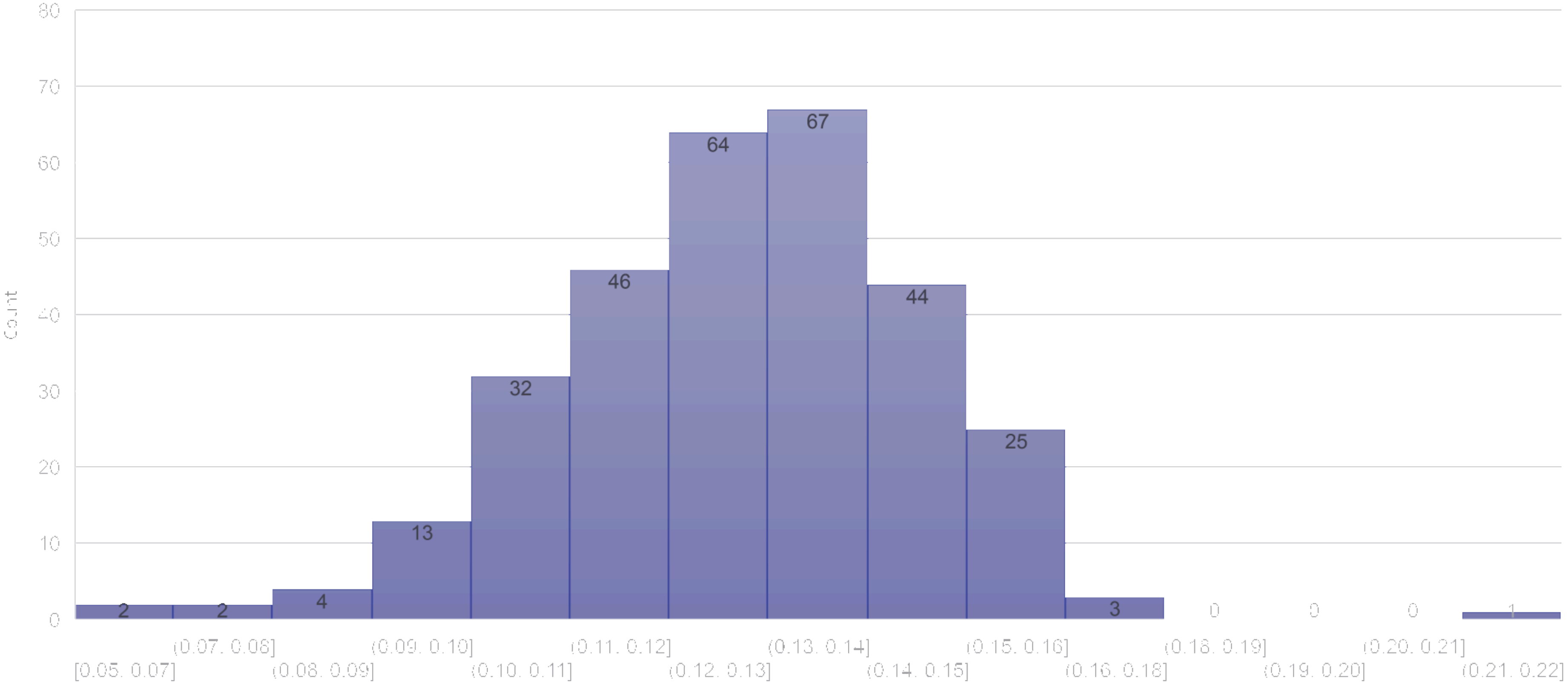


Actual CF	
Mean	.1278
Median	.1287
Min	.0541
Max	.2172

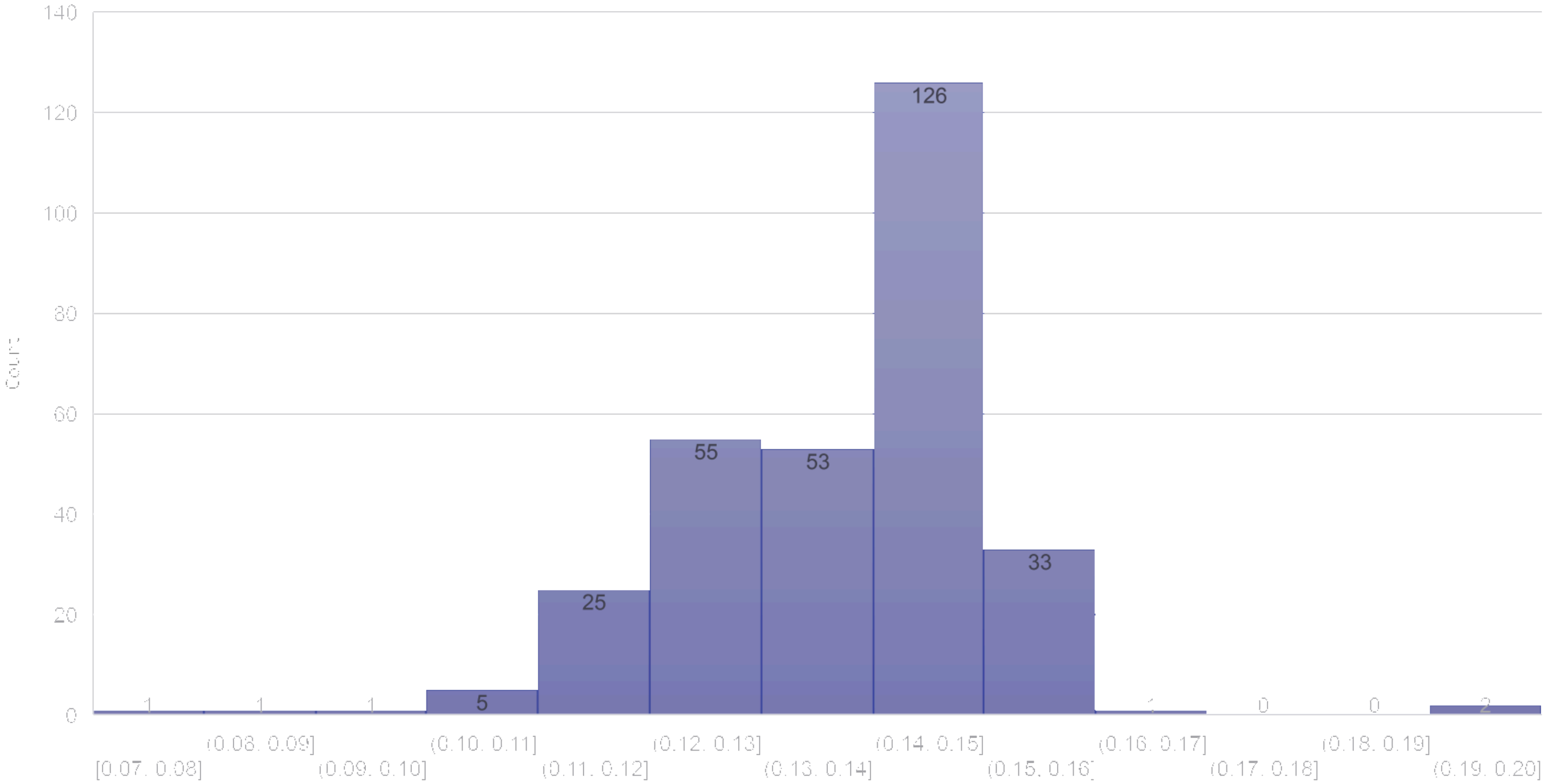
PV Watts CF	
Mean	.1394
Median	.1432
Min	.0718
Max	.1987

- **NG Estimate and PV Watts both appear to be overestimates**
- **Actual CF mean is 8.7% lower than 14%**
- **Actual CFs are more diverse and skewed downward, vs tighter and skewed upward with PV Watts**

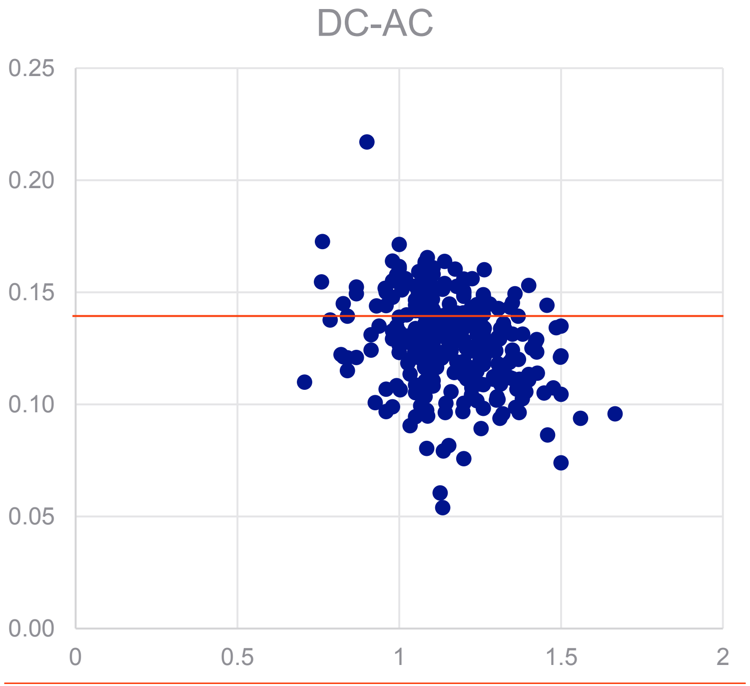
Actual Generation Capacity Factor Distribution



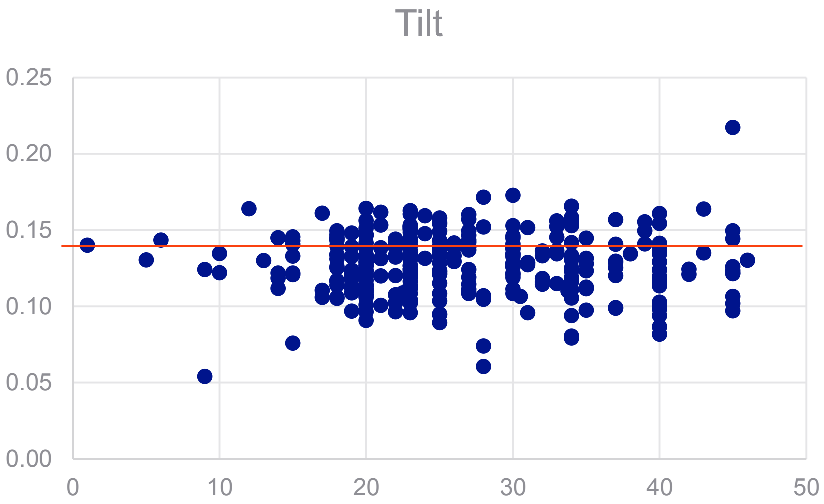
PV Watts Capacity Factor Distribution

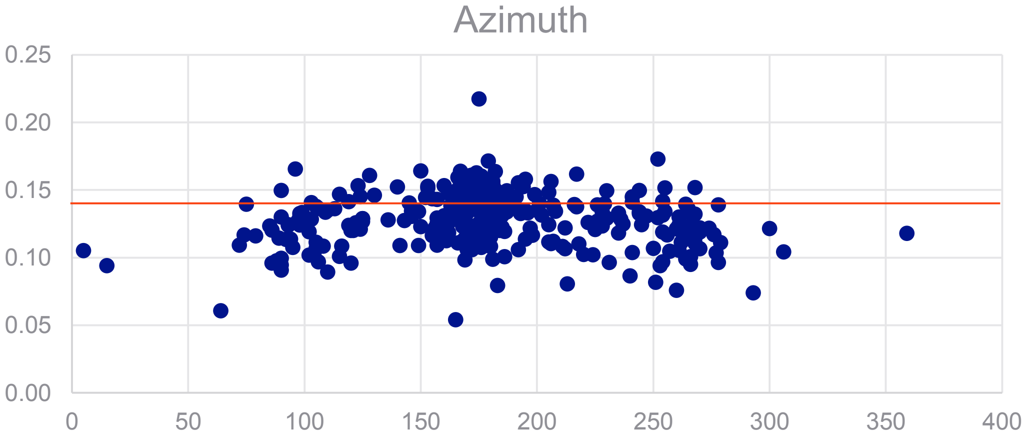


How do inputs affect actual CF?



NG Estimate in orange





Suggested Approach is a Table with CFs for Ranges of Angle and Azimuth

ACTUAL CFs		Tilt	
Direction	0-20	20-40	40-60
North	10.51%	9.37%	10.59%
East	12.76%	12.15%	11.50%
West	12.25%	12.15%	11.50%
SW & SE	12.54%	12.90%	13.21%
Due South	13.11%	13.57%	13.67%

PV WATTS		Tilt	
Direction	0-20	20-40	40-60
North	9.98%	8.37%	8.09%
East	12.80%	12.89%	12.60%
West	13.00%	12.83%	12.45%
SW & SE	14.15%	14.63%	14.38%
Due South	14.31%	15.14%	15.21%

- **Actuals vary from PV Watts with modest variation**
- **Need to investigate higher CFs for northerly systems**
- **May suggest a minimum CF to account for shading, snow and other factors**

Difference		Tilt	
	0-20	20-40	40-60
North	-0.53%	-1.00%	-2.50%
East	0.04%	0.74%	1.10%
West	0.75%	0.68%	0.95%
SW & SE	1.61%	1.73%	1.17%
Due South	1.20%	1.57%	1.54%

Takeaways and Next Steps

- Other factors outside of angle and azimuth likely drive the downward measures of actual CFs vs PV Watts
- Use of lower CFs like in table above will generally allow for larger systems at customer locations
- Further analysis of outliers, use of a potential minimum CF, and adjustment of the bands/ranges will further refine this
- Use of an installer supplied CF, validated with the table, is another approach under consideration – CF is currently not collected
- NG is investigating the technical requirements to automate the use of CF based on angle and azimuth inputs in Grid Force

Appendix

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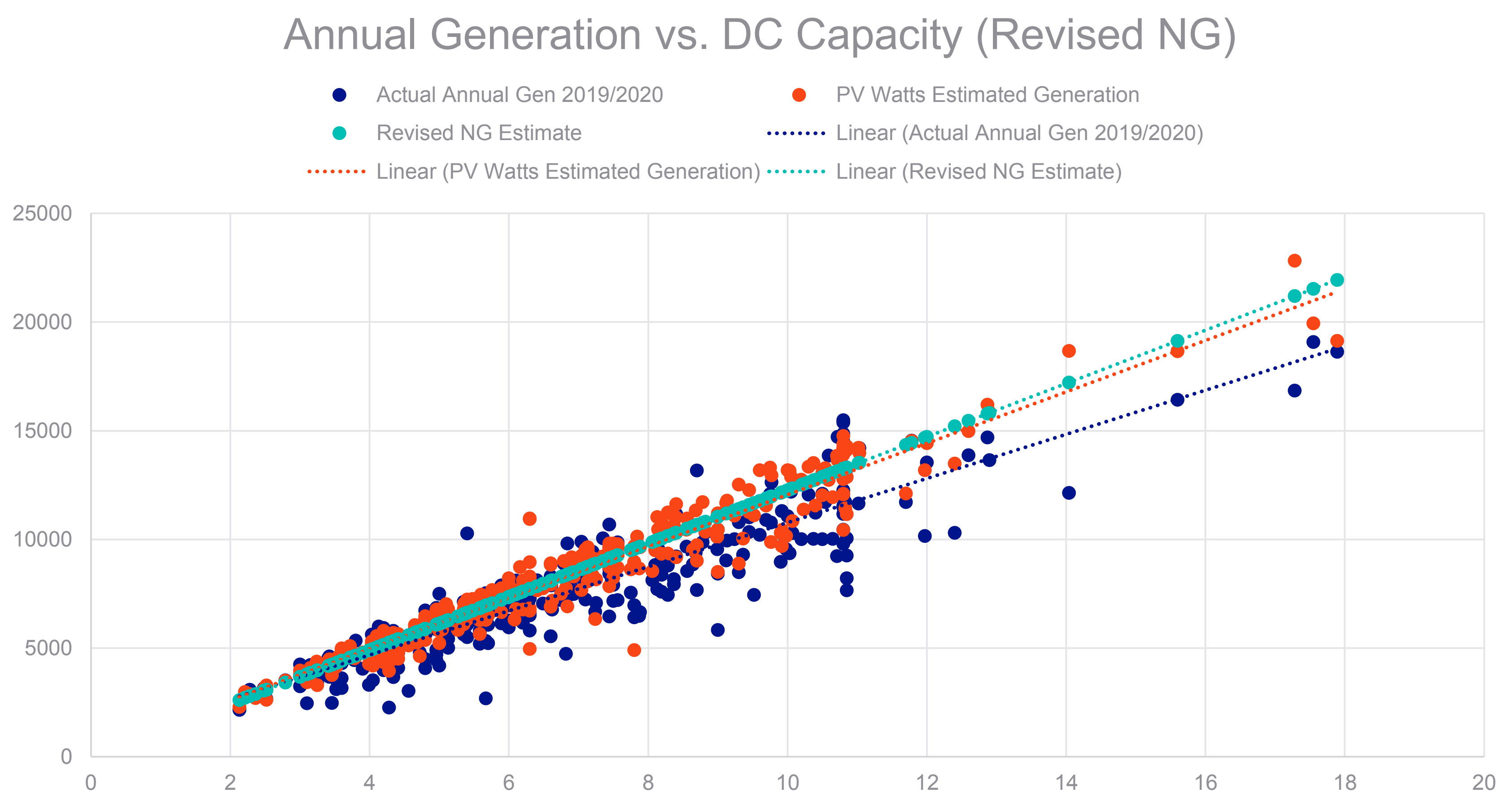
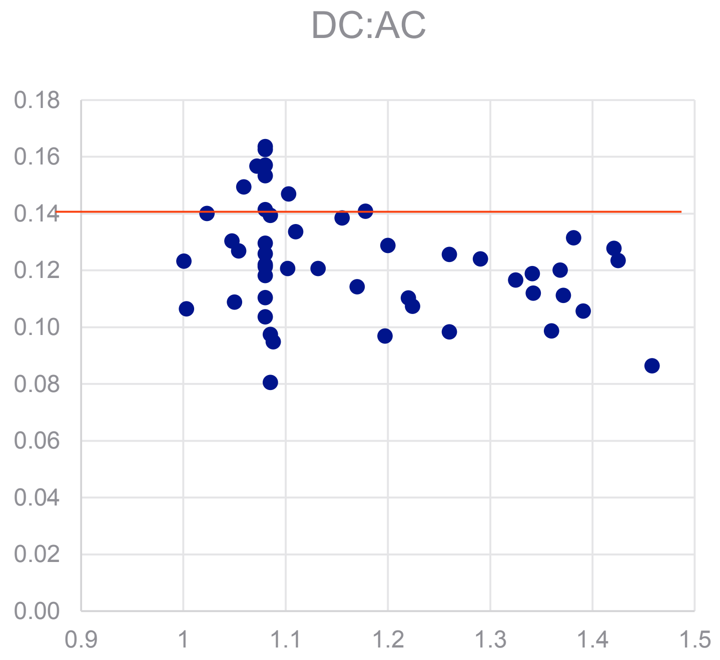
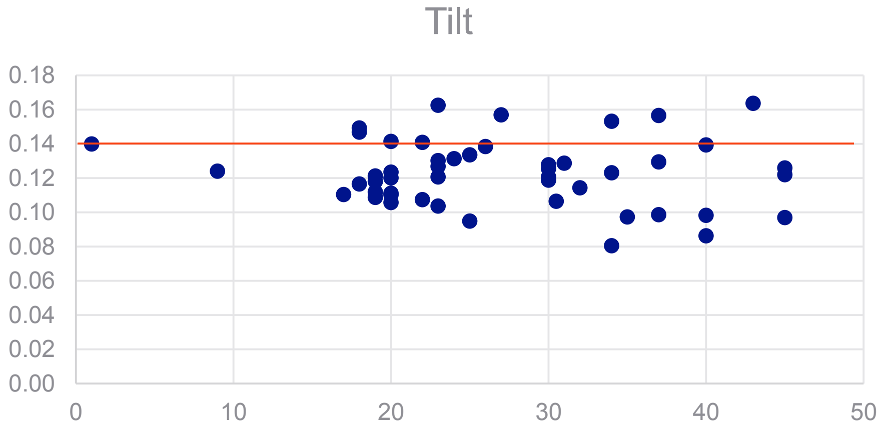
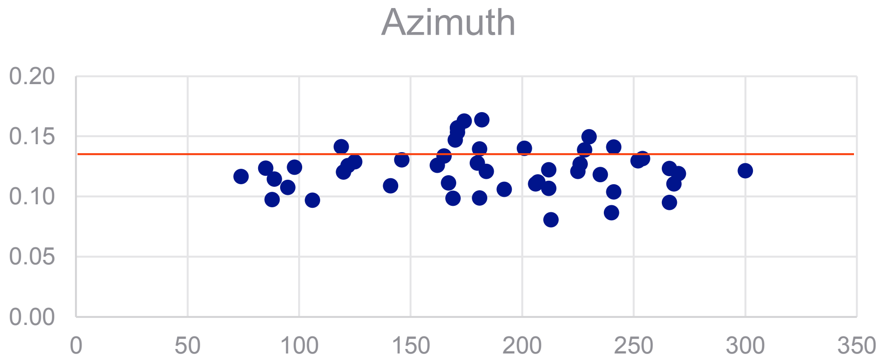

Annual Generation vs. DC Capacity (Revised NG)
Actual Annual Gen 2019/2020
PV Watts Estimated Generation
Revised NG Estimate
Linear (Actual Annual Gen 2019/2020)
Linear (PV Watts Estimated Generation)
Linear (Revised NG Estimate)
25000
20000
15000
10000
5000
0
0
2
4
6
8
10
12
14
16
18
20

How do inputs affect actual CF for large systems? (systems > 10 kw)







Sustainable
Energy
Advantage, LLC

Rhode Island Renewable Energy Growth Program:

Potential Approach for Mitigation of REG Project Owner Federal Tax Credit Risk Associated with Long Interconnection Construction Periods for 2023 Program Year

September 29, 2021

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Reminder RE: Institutional Roles Associated with the Renewable Energy Growth Program

- Under the Renewable Energy Growth Act, the Distributed Generation (DG) Board is explicitly charged with setting Ceiling Prices, based on factors listed in R.I.G.L. § 39-26.2-5(d)(1)-(5)
  - In that process, the **Office of Energy Resources** (OER) serves as dedicated staff to the Board, and serves as the Board's main liaison with the consulting team (SEA and Mondre Energy, Inc.). The consulting team's scope in recommending Ceiling Prices are limited to the factors discussed in § 39-26.2-5(d)(1)-(5) (the same factors the Board can utilize)
  - **Narragansett Electric Co (d/b/a National Grid)** is charged with developing and/or revising language in the REG tariffs, as well as development/revision of solicitation and enrollment rules and procurement of projects in line with the rules (and statute)
- The **Public Utilities Commission** (per R.I.G.L. § 39-1-3) has the sole authority to approve modifications to National Grid tariffs (which include the DG interconnection tariff, which governs interconnection to the distribution system)
- The **Federal Energy Regulatory Commission** (FERC) has the sole authority to approve changes to sections of the ISO-NE tariff surrounding Affected System Operator (ASO) studies, or changes to New England Power's Local Network Service (LNS) tariff (also part of the ISO-NE tariff)
- **Bottom Line:** OER and the DG Board **cannot recommend changes to interconnection policy or tariffs** through the annual Ceiling Price process, but **can recommend approaches related to Ceiling Price design** related to interconnection and interconnection cost issues

Stakeholder Feedback Regarding Impacts of Interconnection on Projects

- Since 2019, REG stakeholders have indicated that interconnection delays have (as in other jurisdictions) increased as a result of increased DG penetrations, which lead to longer timelines associated with both transmission-level and distribution-level interconnection studies and construction.
- This feedback from stakeholders includes, but is not limited to:
  - **Increased distribution study timelines and costs** (whether individually/for groups)
  - The increasing likelihood that any projects ≥1 MW will be **included in transmission-level Affected System Operator (ASO) studies** (along with associated costs and risks)
  - The increasing risk that projects (as in Massachusetts) **run the risk of being assessed extremely high ($100/kW-$2,000/kW) system modification costs** as a result of either ASO or distribution-level studies, and of being subject to **delays of up to 4-5 years**
  - The increasing **assessment of Direct Assignment Facilities (DAF) charges** by New England Power
  - 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%**, per current tax law)
- Consulting Team Assessment: A large number of currently-proposed projects (<u>including those already constructed</u>) subject to these delays, costs and uncertainties could potentially be canceled

Practical Challenges Related to Accounting for Potentially Increased Transmission Interconnection Costs in Ceiling Prices

1. Lack of (current) clarity from PUC following Docket 5077 regarding approach to Direct Assignment Facility (DAF) charges/other more complex questions of distribution or transmission interconnection cost allocation in the case of very costly transmission/distribution upgrades functionally caused by a group of projects (rather than just one “cost causer”)
   - **Impact/Implication:** Unclear what degree to which system modification costs may ultimately be shared, and thus unclear how to account for said cost sharing in the Ceiling Prices
2. Lack of finalized ASO results for any project in Rhode Island (as of this writing)
   - **Impact/Implication:** Inhibits accounting for actual transmission system modification costs and their prevalence amongst REG projects
3. Ongoing risk following initial ASO study of requirements for re-study following the attrition of other projects
   - **Impact/Implication:** Can render finalized study results unable to fully and finally account for actual cost of eventual system modification needs

Bigger-Picture Challenges/Concerns Related to Accounting for Potentially Increased Transmission Interconnection Costs in Ceiling Prices

4. Risk associated with (functionally) socializing costs of siting in locations that National Grid has said that development of >1 MW projects have a risk of requiring substantial costly upgrades
   - **Impact/Implication:** Increasing interconnection costs to account for transmission system modifications more broadly could incentivize development in inappropriate locations that require large and costly transmission upgrades
5. Strict "cost causation" methodology utilized by ISO-NE for transmission system modifications that focuses on the individual "cost causing" project
   - **Impact/Implication:** Difficult to know/understand how common it is that an individual project or projects will actually incur such system modification costs (or for developers to know how much they might possibly be)
6. The risk of project attrition resulting from project delays unrelated to system modification costs
   - **Impact/Implication:** Even if Ceiling Prices were increased to account for ASO impacts, the long delays (up to 4-7 years as observed in MA) might still not incentivize the project to reach commercial operation

Challenge/Concern Regarding Interaction of Current Rules with Emerging Interconnection Realities

- REG rules provide an indefinite extension for projects that are "mechanically complete" at the time of Output Certification, but…
  - "Safe harbor" deadlines in the federal tax credits provide for a firm requirement to be "placed in service" or otherwise lose eligibility for (in the case of the ITC) the expanded credit values of 26% and 22% by December 31, 2025
  - There is **no corresponding requirement that National Grid must interconnect projects by project "safe harbor" deadlines**, and developers cannot easily or clearly compel them or New England Power (the ASO) to act in a timely fashion
  - The ITC and ILoPTC, as upfront credits, provide a large proportion of the net present value of the project
- **Without an adjustment to their compensation rates**, a loss of tax credit eligibility at the safe-harbored rate would require projects to be re-priced, and there would be a credible risk that projects at risk of losing their ITC/ILoPTC eligibility by not being "placed in service" in time would be canceled.

Federal Investment Tax Credit (ITC) Eligibility and "Safe Harbor" Deadlines

- **Credit Amount:** provides a 26% Year 1 credit for eligible costs associated with Solar projects for both individual and "begin(ning)…construction" through December 31, 2022, and a 22% Year 1 credit for eligible costs associated with Solar projects **"begin(ning)…construction" through December 31, 2023**
- **Safe Harbor Eligibility:** Projects able to demonstrate compliance with the Five Percent Safe Harbor or Physical Work Test in IRS Notice 2018-59 (currently) qualify for credits at "safe harbored" 26% and 22% values by being **"placed in service" no later than December 31, 2025**
- **Treatment Post-Safe Harbor Date:** The value for projects financed by business taxpayers unable to meet the December 31, 2025 deadline will receive (under current law) is a 10% credit,
  - NOTE: The value available to projects financed by individual taxpayers is 0%.

Federal Investment Tax Credit in Lieu of Production Tax Credit (ILoPTC) Eligibility and "Safe Harbor" Deadlines

- Currently allows any projects eligible for the Production Tax Credit (PTC) to qualify as "energy property" under the ITC at a 30% value if they "begin…construction" no later than December 31, 2021 (but limits Wind projects to 60% of that value)
- Functionally, this allows 2021 PY Anaerobic Digestion (AD) projects to receive a 30% credit and allows Wind projects to receive an 18% credit (30%*60%), and can "safe harbor" that credit value for up to four years as long as a project undertakes "continuous program of construction" (per IRS Notice 2013-29)
- Projects unable to maintain a "continuous program of construction" following December 31, 2025 will receive no credit (0%)
- **NOTE:** Except for Small Scale Hydroelectric projects, the REG Ceiling Prices assume all eligible projects (except Small Scale Hydroelectric) can fully monetize available federal tax credits

Current REG Certificate of Eligibility Timelines

- Small- and Medium-Scale Solar Projects
  - No Output Certification required, but projects lose Certificate of Eligibility within 24 months if not operational
- All Other Projects
  - Output Certification must be provided within 24 months for Solar and Wind projects (excl. hydro and Anaerobic Digestion, which have 48 and 36 months, respectively), including that **both the project and "<u>all interconnection facilities necessary for operation</u>" must be completed**
  - Initial six-month extension available for no additional performance guarantee deposit, plus additional six-month extension for additional performance guarantee deposit equal to ½ of initial deposit, but no further extensions available
  - Importantly "interconnection facilities necessary for operation" **<u>does not</u>** include EDC or ASO-side upgrades, meaning that **projects that are constructed and otherwise able to certify mechanical completion projects have essentially unlimited allowance**

Initial Proposed Approach for 2023 Ceiling Price Development

- Allow projects ≥1 MW for which their statutory/IRS-determined “safe harbor” placed-in-service deadline has lapsed (resulting from ASO-related **circumstances beyond their control**) the option to have their compensation rate adjusted to account for tax credit eligibility loss
  - However, **value would be scaled based on the percentage difference between Ceiling Price and as-bid PBI value** (to preserve proportionate initial benefits of competition from Open Enrollment results)
- Eligibility would be subject to:
  - Successful Output Certification (as described herein and in the Solicitation and Enrollment Rules);
  - Certifying (to National Grid’s satisfaction) that:
    - The project has undertaken appropriate efforts to maintain “safe harbor” eligibility (as required by all relevant IRS Notices)
    - The project only awaits ASO/transmission system-related modifications with ASO-related construction or other delays beyond its control

Formula for Potential Solar Compensation Rate Adjustment (₵/kWh)

$$2023\ PY\ Accepted\ PBI\ Rate +$$

$$\left(\left(\begin{matrix}2023\ Ceiling\ Price_{10\%\ ITC} - \\ 2023\ Ceiling\ PriceFinal\ _{Approved}\end{matrix}\right) * \left(1 - \left(\frac{2023\ Ceiling\ PriceFinal\ _{Approved} - 2023\ PY\ Accepted\ PBI\ Rate}{2023\ PY\ Accepted\ PBI\ Rate}\right)\right)\right)$$

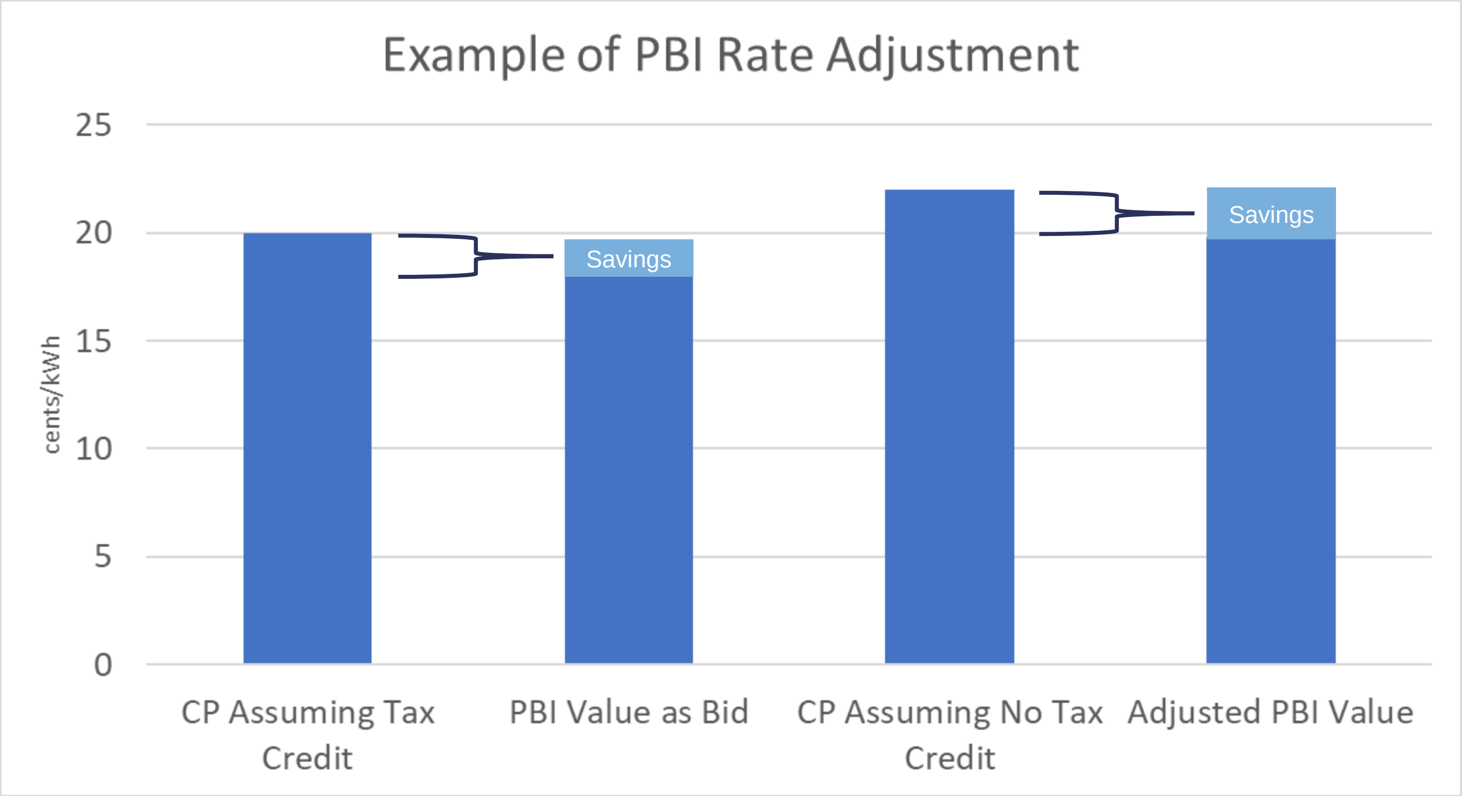
Formula for Potential Non-Solar Compensation Rate (As Adjusted) (₵/kWh)

$$2022\ PY\ Accepted\ PBI\ Rate +$$

$$\left(\begin{matrix} 2022\ Ceiling\ PriceNo_{\ ILoPTC} - \\ 2022\ Ceiling\ PriceFinal_{\ Approved} \end{matrix}\right) * \left(1 - \left(\frac{2022\ Ceiling\ PriceFinal_{\ Approved} - 2022\ PY\ Accepted\ PBI\ Rate}{2022\ PY\ Accepted\ PBI\ Rate}\right)\right)$$

Example of Adjusted Compensation Rate

- An illustrative example of how the adjustment would be applied is shown below



Note: Values above are illustrative

Big picture takeaway: Proposed adjustment would preserve cost-savings from bids below the CP value on a proportional basis while providing sufficient PBI to offset expiration of ITC eligibility

Questions/Requests for Stakeholders (1)

1) If a version of the Build Back Better Act (the budget reconciliation legislation currently under consideration in Congress) with a long-term federal tax credit extension for eligible REG projects is ultimately enacted, the proposal described herein may be rendered moot, given that projects may face system modification delays that are significantly shorter than their eligibility term for federal tax credits.
   a) Do you agree with this characterization? Why or why not?
2) What types of documents do you believe your firm could provide to National Grid in order to certify:
   a) The date by which the project availed itself of safe harbor eligibility; and
   b) That the project maintained its "safe harbor" eligibility for federal tax credits until the time of eligibility expiration?

Questions/Requests for Stakeholders (2)

3) Has your firm ever dealt with a distribution interconnection study and/or construction delay long enough to place your tax credit safe harbor eligibility at risk? If so, please describe the circumstances (e.g., the project size, renewable energy class, along with safe harbor eligibility and interconnection timelines).
4) Are there other approaches <u>unrelated to</u> either federal tax credits or accounting for the cost of either transmission or distribution interconnection in the Ceiling Prices you believe can and should be implemented during the 2023 program year?

Request for Comments

- Please submit written comments on the four questions discussed on the previous pages **no later than the close of business October 8, 2021** to jkennerly@seadvantage.com. **Comments not submitted in a PDF attachment or not submitted on company letterhead will not be considered.**

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September 30, 2021

Memorandum To: Jim Kennerly

From: Mike Brennan, Gregory L. Booth, PLLC
On Behalf of Rhode Island Division of Public Utilities and Carriers

RE: Request for Comments on 1st Draft Ceiling Prices and Other Matters

CC:
Jason Gifford
Toby Armstrong
Chris Kearns
Shauna Beland

Jim,

On September 8, 2021 SEA presented to stakeholders the second draft of the ceiling price calculations for the 2022 program year for the Rhode Island Renewable Energy Growth Program. In that meeting, you requested that stakeholders provide written comments on the materials presented by September 30th. The Division appreciates that opportunity to participate in this process and offers the following comments as requested. We look forward to continuing to engage with stakeholders in this process going forward.

Project Costs

The second draft ceiling prices include a range of prices based on different approaches to project upfront costs (high and low). This is an extension of the analysis completed in the first round and is informed by updated feedback from stakeholders and data regarding inflation (PPI) and recent estimates from NREL. The Division believes that it is prudent to continue to calculate the ceiling prices using a range of estimates for project costs but recognizes that this process must conclude with a single ceiling price for each class. The Division also recognizes that predicting the actual impacts of inflationary pressures, trade related impacts on key components, and potential easing or further constricting of supply chain constraints will be problematic at best. Absent any emerging evidence to support a different conclusion, the Division recommends using the low end capital cost estimates from the second draft analysis. This results in <u>increases</u> in the ceiling prices over the 2021 prices ranging from 2% to 21% for Wind and Solar (with the exception of Large Solar, which would see a 5% decrease). The Division understands that SEA is soliciting feedback directly from stakeholders in the Hydroelectric sector, to better understand current price pressures for that Class. The Division is withholding comment on that class until more information is provided.

The current complexity and uncertainty in estimating project costs, further supports the need to gather as much accurate and timely information as possible on project costs. To that end, the Division reiterates recommendations that National Grid and key stakeholders establish a mechanism in the bid submission process in 2022 to require submission of detailed capital cost estimates, and for awarded projects to provide details on actual costs once projects are completed. This will strengthen the process of estimating this key input to the ceiling prices going forward.

Post Tariff Market Prices

The Division reiterates its support of the recommended approach for estimating post tariff revenues based on escalated retail rates. The Division continues to believe that assuming more than 60% of escalated retail rates should be considered and recommends using 80%.

Tax Considerations

The Division observes that the Small Solar I class is targeted to residential installations. The current approach to setting the price for this class assumes that the value of the PBI's, which are realized as customer bill credits, and not cash payments, is taxable income for federal and state income taxes. It is the Division's understanding that these credits are typically not taxable income and notes that the tax policy guidance that National Grid publishes on this matter (see attached file). Specifically, that guidance states: "Bill credits provided to residential customers will not be reported as income because National Grid will not be procuring energy from such systems. Residential customers only receiving bill credits, and not receiving PBI payments as the Applicant, do not need to provide a W-9."

The Division believes that the Small solar I calculations for the Ceiling Price should not assume that the "revenue" received in the form of bill credits is taxable income. This recommendation would have no impact on the approach to the value of the ITC.

RE_Growth_Tax_Policy_2017.pdf