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

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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

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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, <u>only two Small Solar participants</u> 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 written 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 **<u>multiple hundreds of MW of projects in a late stage of development will be cancelled</u>**
- 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

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 written 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

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

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

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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