Rhode Island Renewable Energy Growth Program:

Research, Analysis, & Discussion in Support of Second Draft 2023 Program Year Ceiling Price Recommendations

September 22, 2022

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Summary Results, Solar Classes (¢/kWh)

Technology	Tariff Term (Years)	Size Range kW (Modeled Size kW)	2022 Approved CP	2023 1st Draft Proposed CP	2023 2nd Draft CP (Including Post-Tariff Revenue)	% Change (2022→2023)	2023 2nd Draft CP (No Post-Tariff Revenue)	% Change (2022→2023)
Small Solar I	15	0-15 (5.8)	31.05	29.85	**27.75**	**-11%**	**32.25**	**4%**
Small Solar II	20	>15-25 (25)	27.55	25.95	**26.15**	**-5%**	**26.85**	**-3%**
Medium Solar	20	>25-250 (250)	24.45	23.65	**25.25**	**4%**	**26.25**	**8%**
Commercial I	20	>250-500 (500)	19.25	19.35	**21.75**	**13%**	**22.65**	**18%**
Commercial I CRDG	20	>250-500 (500)	22.14	22.25*	**24.35**	**10%**	**25.35**	**14%**
Commercial II	20	>500-1,000 (1,000)	15.75	16.45	**18.35**	**17%**	**19.35**	**23%**
Commercial II CRDG	20	>500-1,000 (1,000)	18.11	18.92*	**21.10***	**17%**	**22.25***	**23%**
Large Solar	20	>1,000-5,000 (5,000)	10.95	12.55	**14.15**	**29%**	**15.95**	**46%**
Large Solar CRDG	20	>1,000-5,000 (5,000)	12.59	14.43*	**16.27***	**29%**	**18.34***	**46%**

*This is the maximum CRDG Ceiling Price allowed by law. For the CPs excluding post-tariff revenue, the calculated 2023 values are 22.45 for Commercial CRDG >500-1,000 and 19.05 for Large CRDG. For the CPs including post-tariff revenue, the calculated 2023 values are 21.45 for Commercial CRDG >500-1,000 and 17.25 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.

Summary Results, Non-Solar Classes (¢/kWh)

Technology	Tariff Term (Years)	Size Range kW (Modeled Size kW)	2022 Approved CP	2023 1st Draft Proposed CP	2023 2nd Draft CP (Including Post-Tariff Revenue)	% Change (2022→2023)	2023 2nd Draft CP (No Post-Tariff Revenue)	% Change (2022→2023)
Wind	20	<=5,000 (3,000)	22.4	19.10*	**18.55**	-17%	**20.25**	-10%
Wind - CRDG	20	<=5,000 (3,000)	24.6	21.15*	**20.55**	-16%	**22.35**	-9%
Hydroelectric	20	<=5,000 (500)	37.15	39.85	**38.35**	**3%**	**39.95**	**8%**
Anaerobic Digestion	20	<=5,000 (750)	25.55	19.65	**18.65**	-27%	**18.65**	-27%

*Average of (1) 90% bonus depreciation and (2) no bonus depreciation

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Overview of Key Stakeholder Feedback and Modeling Implications

Solar Installed Costs (1)

- Typically, most of the solar capacity is procured in the 1st Open Enrollment of each year
- However, 1st Open Enrollment of 2022 PY resulted in procurement of:
  - 1.455 MW of 5 MW in Medium Solar solicited;
  - 2.61 MW of 12 MW in Commercial Solar capacity solicited; and
  - **0 MW** of 24.5 MW solicited
- **Only one Large bid was received**, but was disqualified for exceeding the maximum per-project nameplate capacity
- SEA initially viewed the 1st Open Enrollment results as anomalous, and driven in part due to **confluence of enrollment with Biden Administration's anti-dumping/countervailing duty (AD/CVD) investigation** that froze a significant degree of project development regionally and nationally
- However, preliminary (and forthcoming) data from the 2nd Open Enrollment suggests a **similarly limited number of bids** (relative to typical recent experience)

Solar Installed Costs (2)

- Even though SEA attempted to foreshadow the increase in inflation (and the delayed response by the Federal Reserve), lack of bids suggests **the market is experiencing increased project costs beyond what was contemplated in 2022 PY ceiling prices**
- The main goal of setting bid price caps in a procurement-based program is to ensure that said caps **sufficiently reflect market conditions at the time of the procurement** and thus **encourage healthy competition**
- The results for the 1st Open Enrollment (and the forthcoming results of the 2nd Open Enrollment) suggest that both the 2022 PY prices are **too low to encourage bids**, and thus represent unhealthy competition
  - Crucially, the 1st Draft 2023 prices **were based on a similar installed cost methodology**
- Considering these results, **SEA believes it is necessary for the long-term health of the program to increase assumed installed costs** to **ensure sufficient and competitive bids are received** in 2023 PY and reduce the risk that the program will fail to meet its statutory objectives

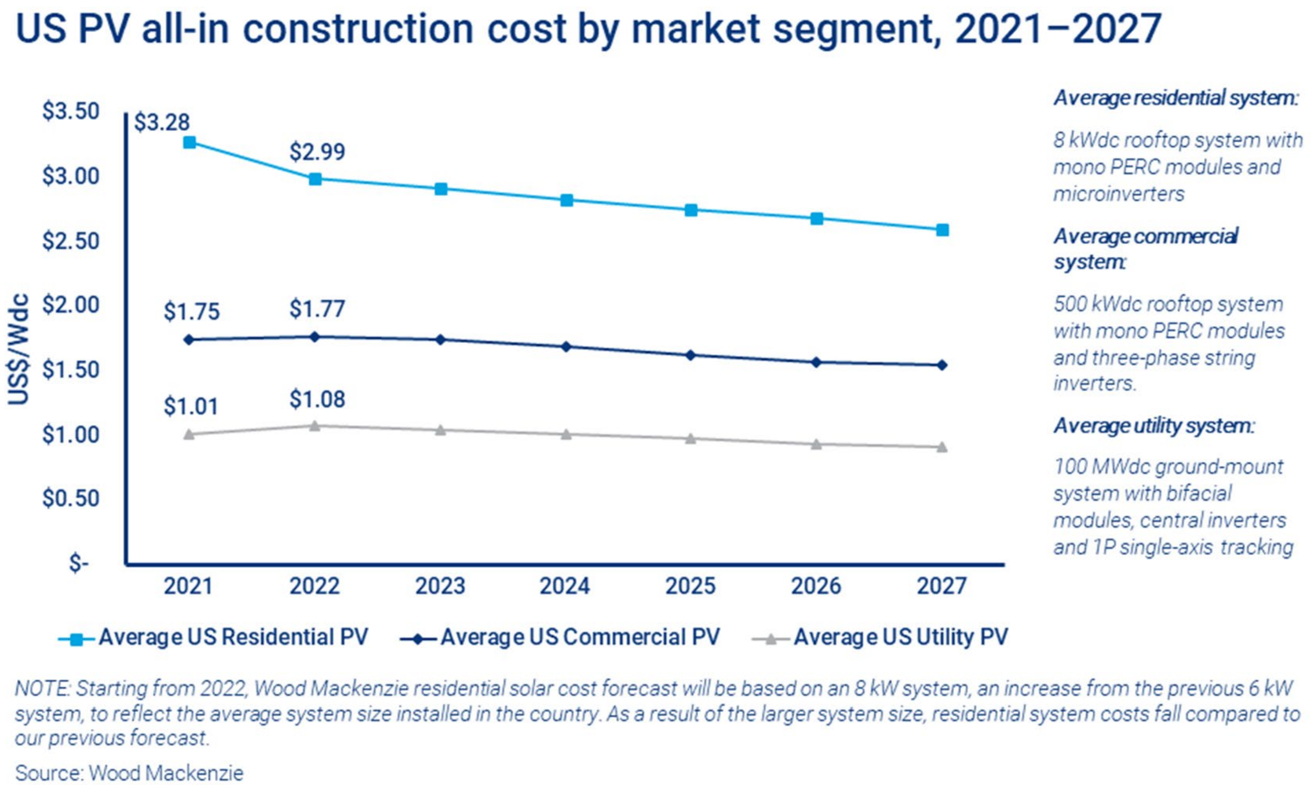
Solar Installed Costs (3)

NOTE: Highlighted bold red text = restatement of modeling assumption relative to initial PPT to reflect actual assumption modeled **(change to statement of M.I. =/= change in 2nd Draft CPs)**

- Historically, SEA has aimed to incent projects that represent the **lowest quartile** of project costs from other jurisdictions (save for NY, where Upstate build costs are much lower) in order to mitigate ratepayer costs
- However, as noted on prior slide, **recent Open Enrollment results suggest these values are too low**, and SEA plans to adjust the quartile of selected cost to **enable the receipt of competitive, market-based bids** representing projects **likely to reach commercial operation**
  - SEA also intends to limit the inclusion of bid data to the current program year (rather than the current and prior program year)
- **Modeling Implications:**
  - **Calibrate installed cost averaging based on (actual and expected) 2022 PY results**
    - **Utilize averages of median and 25th percentile (rather than 25th percentile) values from state databases and REG bid values for all Medium and Commercial projects**
    - **Utilize averages of average and median (rather than 25th percentile) values from state databases and REG bid values for all ~~Commercial and~~ Large Solar projects**
    - **No change for Small I/II**
  - **Eliminate use of bids from prior PYs (to ensure bids representing costs from up to two years ago are no longer included in proposed ceiling price calculations)**

Year-on-Year Cost Decline Assumptions (Solar)

- SEA initially adopted 2022 NREL ATB Moderate case
- A variety of stakeholders have indicated there has been **little reduction in either current costs or future expectations**
- Recent Wood Mackenzie analysis (at top right) suggests 2022-23 year-on-year reductions nationally **likely to be no greater than 2%**
- **M.I.: Adopt 2022 NREL ATB Conservative case for 2022-23 YoY decline over Moderate case (see specific values at bottom right)**



Solar Class	2023 1st Draft (2022-2023 Change, 2022 ATB Moderate Case)	2023 2nd Draft (2022-2023 Change, 2022 ATB Conservative Case)
Small Solar I & II	-7.4%	**-1.6%**
Medium/ Commercial Solar	-4.9%	**-0.8%**
Large Solar	-4.1%	**-0.2%**

Incremental Cost of Inflation Reduction Act Apprenticeship Requirements

- ***IRA provisions go further than RI law*** by requiring certified apprentices to complete successively larger proportions of project hours (10% in 2023)
- However, initial research (including **analysis from the U.S. Department of Commerce**) indicates that requiring certified apprentices in a variety of fields **could in fact <u>reduce</u> (rather than increase) installation labor costs**
- **M.I.s:**
  - **Continue to adopt $57.50/kW added value for prevailing wage**
  - **Considering both uncertainty about impact and significant change to installed cost methodology, defer any change related to certified apprentices (if any) until 2024 PY**

Interest Rate on Term Debt (1)

- For 1st Draft prices, SEA utilized the same approach as it used for the 2022 prices, which was to estimate the change in interest rates based on changes in 10- and 20-year US Treasury and overnight financing rates
- DPUC comments questioned this methodology
- However, for the 2nd Draft, **SEA has accessed a term sheet from a (redacted) debt financier**, indicating that current rates for a portfolio of Rhode Island projects can receive debt financing for:
  - A 10-year term
  - The equivalent US Treasury yield on the date of closing; and
  - A risk premium of +325 bps
- To adapt this value to wind and hydro, SEA assumed **an additional 25 bps premium** to account for the modest increase in production risk
- **M.I.: Adopt interest rates on term debt & debt tenor shown on next page**
  - **Debt tenor based on average of 10-year term with existing 15-year values for Medium and Commercial (the subject of the interest rate quote, based on the developer supplying the quote)**

Interest Rate on Term Debt (2)

Row	Solar Class	Notes	Medium Solar	Comm'l Solar/ Comm'l CRDG	Large Solar/ Large CRDG	Wind/Wind CRDG	Anaerobic Digestion	Small-Scale Hydroelectric
A	**Debt Term (Years)**	Med & Comm'l = average of 10 and 15 year values	13	13	15	15	15	20
B	**10-Year Treasury Yield**	Value on 9/9/2022	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%
C	**20-Year Treasury Yield (9/9/2022)**	Value on 9/9/2022	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
D	**Effective 15-Year Treasury Value (for Swap)**	Avg of B & C	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%
E	**Effective 13-Year Treasury Value (for Swap)**	Avg of B & D	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
F	**Applicable Treasury-Based Value**	Based on A	3.43%	3.43%	3.51%	3.51%	3.51%	3.70%
G	**Risk Premium**	Per stakeholder term sheet	3.25%	3.25%	3.25%	3.50%	3.25%	3.50%
H	**Estimate of Interest Rate on Term Debt**	**F + G**	**6.68%**	**6.68%**	**6.76%**	**7.01%**	**6.76%**	**7.20%**

Impact of Interest in Term Debt Increases on Debt/Equity Shares

- With reduction in interest rates on term debt relative to 1st Draft prices, **it is possible to increase the debt in the capital stack** without violating minimum debt service coverage ratios (DSCRs)
- For all REG-eligible resources, the functional impact of increasing the share of debt is to **reduce ceiling prices relative to the debt assumptions in the 1st Draft**
- **M.I.s:**
  - **Increase Medium Solar debt share to 50% (from 47.5% in 1st Draft), Commercial Solar to 48% (from 47.5%), and Large Solar to 45% (from 42.5%)**
  - **Increase Wind/Wind CRDG debt share to 44% (from 42.5%) and Hydro to 2022 approved level of 70% (from 66% in 1st Draft)**

Inflation Reduction Act (IRA) Financing Impact: Tax Credit Selection (ITC vs. PTC) for Large Solar and Non-Solar Classes

- Previous REG ceiling price modeling has confirmed that **the PTC's 10-year duration results in NPV benefits that are less than the ITC** (and thus result in less economic benefit, **and higher ceiling prices**, when applying)
- However, given the IRA makes solar PV eligible for the PTC, some market participants have indicated that ***at ~$1/W, PTC confers more value than the ITC for large-scale solar (and paired solar/storage)***
- SEA has since modeled PTC utilization for all Solar and Non-Solar classes and can confirm that **utilizing the PTC results in higher prices than the ITC** (see next page for results)
- **M.I.: No change. Based on the installed cost of RI projects, PTC utilization does not provide more value to ratepayers**

Inflation Reduction Act (IRA) Financing Impact: Tax Credit Selection (ITC vs. PTC) for Large Solar and Non-Solar Classes

Renewable Energy Class	2022 PY Approved Ceiling Prices	Estimated 2nd Draft Ceiling Price (Assuming ITC or ILoPTC, and Including Post-Tariff Revenue) (¢/kWh)	% Change from 2022 Approved Ceiling Price	Estimated 2nd Draft Ceiling Price (Assuming PTC, and Including Post-Tariff Revenue) (¢/kWh)	% Change from 2022 Approved Ceiling Price
Small Solar I	**31.05**	27.75	**-10.6%**	35.65	**14.8%**
Small Solar II	**27.55**	26.15	**-5.1%**	34.85	**26.5%**
Medium Solar	**24.45**	25.25	**3.3%**	30.05	**22.9%**
Commercial I	**19.25**	21.75	**13.0%**	25.95	**34.8%**
Commercial I-CRDG	**22.14**	24.35	**10.0%**	28.95	**30.8%**
Commercial II	**15.75**	18.35	**16.5%**	22.25	**41.3%**
Commercial II-CRDG	**18.11**	21.10	**16.5%**	25.55	**41.1%**
Large Solar	**10.95**	14.15	**29.2%**	16.75	**53.0%**
Large Solar-CRDG	**12.59**	16.27	**29.2%**	19.26	**53.0%**
Wind	**22.4**	18.55	**-17.2%**	22.25	**-0.7%**
Wind - CRDG	**24.6**	20.55	**-16.5%**	24.55	**-0.2%**
Anaerobic Digestion	**25.55**	18.65	**-27.0%**	24.95	**-2.0%**

Inflation Reduction Act (IRA) Financing Impact: Interaction of Bonus Depreciation with Tax Credit Transferability Provisions

- Despite the availability of bonus depreciation, market participants indicate **most tax equity investors continue to not utilize bonus depreciation**, to preserve their tax capital to invest in a higher volume of projects.
- DPUC, in comments, suggests that new tax credit transferability provisions should allow project owners to claim bonus depreciation, given that transferability allows investors other than the tax equity investor to benefit from depreciation
- **M.I.: SEA will not be utilizing bonus depreciation in any case, given that now, all 2023 PY resources are eligible for the ITC, PTC or ILoPTC**
  - **Regarding transferability, SEA believes that though transferability could allow some investors to use bonus depreciation when they could not before, it is very preliminary to assume this across the board, and whether it is possible to do it is very specific to the investor in question.**
    - **Furthermore, if in fact someone can use it, then they will be able to bid lower on the ceiling prices (and thereby lower the price), at which time its use will benefit ratepayers without unduly reducing the ceiling price (and limiting healthy competition)**
    - **SEA will continue to consider the impact of transferability as the market evolves post-IRA enactment**

Sponsor/Tax Equity Shares

- Ecogy Energy argues that SEA should not assume a full 30% ITC, given that:
  - Tax equity providers only provide 85 cents/$ in capital contributions to projects; and
  - (Using themselves as an example) that developers are now **unable to utilize their own tax equity** following the pandemic
- **M.I.: SEA will continue to use full-value credits, given that the 85 cents/$1 demands of tax equity investors:**
  - **Is already considered in the CP analysis via the tax equity investor's assumed capital contribution relative to expected benefits streams; and**
  - **Still allows the *project* to monetize the full tax credit value**
- **However, in further recognition of tax equity investor discounts to tax benefit streams, SEA is <u>capping the maximum share of tax equity for solar projects at 35%</u> (per Norton Rose Cost of Capital 2022 webinar data), which requires several (smallish) adjustments to sponsor/tax equity shares**

Inflation Reduction Act (IRA) Financing Impact: Consideration of Allowing Hydro to Qualify for Successor Investment/Production Credits

- For projects <=1 MW, ITC/ILoPTC value increases to 30% **without** min. labor standards
- For projects >1 MW, SEA is certain **the labor requirements' added cost (in exchange for full credit rates) is substantially less than the benefit** of the full 30% ITC (and is unaware of a broad likelihood of non-hydro projects being unable to monetize the credit fully)
  - **M.I.: Assume non-hydro resources are eligible for full tax credits under IRA**
- Separately, DPUC has argued that hydro projects are likely to be eligible for the successor Clean Energy Investment Credit (CEIC) or Clean Energy Production Credit (CEPC), despite risks associated with FERC licensing timelines, **given the CEIC/CEPC eligibility is based on a "placed in service" regime (rather than start construction-based regime)**
- **M.I.s:**
  - **SEA will consider inclusion of CEIC/CEPC for hydro in last round after discussing with hydro market participants**
  - **If such tax credits are applied, SEA will model based on assumed CEIC or CEPC for comparison of lowest relative cost for ratepayers**

Post-Tariff Project Revenue Assumptions (1)

- Stakeholders continue to argue that including post-tariff revenue in the ceiling price calculation is inappropriate, arguing:
  - For small/medium projects - uncertainty exists post-tariff regarding rooftop replacement and lease availability (and the cost of said lease if extension is available)
    - For rooftop facilities that are removed at year 20 for re-roofing, SEA must consider the costs of re-installing the facility (~$0.30/W) or it gives a competitive advantage to ground-mounted facilities
  - Financiers do not consider revenue beyond the term of the tariff
  - Switching to net metering would require a costly reconfiguration of the system from a front-of-meter generator to a behind-the-meter generator, and utility review of the project change (12-16 months)
  - Switching to net metering would require costly customer acquisition/management

Post-Tariff Project Revenue Assumptions (2)

- **Rooftop warranty and lease issues**
  - SEA's market research suggests lease terms of 20 years, with an option for extension for an additional 5 years, are common ➔ key question is, what are the provisions for extension and are they at the tenant/project owner's option?
  - Stakeholders (including Ecogy Energy) have supplied SEA with lease terms which give option to project owner or require mutual agreement
  - Overall, it initially appears that certain rooftop facilities will experience challenges extending the useful life beyond 20 years, but that extensions up to 25 years are sufficiently common to justify consideration of post-tariff revenue for such facilities
  - **M.I.: SEA intends to conduct additional research regarding cost increases to lease payments if an extension is elected**
- **Financiers' consideration of post-tariff revenue**
  - As discussed in the Draft 1 CP presentation, SEA accounts for post-tariff revenue not for the purpose of determining repayment of debt (which in all cases, will mature prior to the end of the REG tariff term), but rather to mirror the perspective of all project owners considering the economics of a project investment.

Post-Tariff Project Revenue Assumptions (3)

- **Reconfiguration and customer acquisition costs**
  - SEA agrees that it is not appropriate to include post-tariff revenue that requires significant re-engineering of a facility (and resulting re-study by the utility)
  - However, ambiguity exists regarding if statute requires REG facility to re-configure to behind-the-meter and acquire offtake in order to receive net metering compensation
  - *Statute provides that "**After the end of the term** **of the performance-based incentive tariff** applicable to a distributed-generation project, **net-metering credits for excess generation in any given month shall be credited to the net-metered account at the applicable rate allowed under the law (emphasis added)**."*
  - Key question: Are REG facilities entitled to post-tariff net-metering credits irrespective of project configuration?
  - **M.I.: Since SEA's role is not to interpret statute → will provide two sets of ceiling prices to PUC to allow PUC to determine appropriate set of assumptions based on their reading of statute**

Ceiling Price Options	CP Option 1	CP Option 2
Include Post-Tariff Revenue?	No	Yes
Include post-tariff re-configuration costs?	No	No
Assume statute allows for NM compensation post-tariff irrespective of project configuration?	No	Yes

Solar >25 kW Operating Expense Assumptions (1)

- **Fixed O&M Costs:**
  - One stakeholder provided O&M cost quotes that were marginally higher than SEA's current assumed values
  - SEA was able to verify the scope of such costs and concluded that a portion of costs are already accounted for in project management cost inputs
  - However, O&M costs sans project managements costs were still higher than SEA's prior inputs for Large Solar
  - **M.I.: Adopt stakeholder fixed O&M input for large solar ($8 ➔ $11/kW/yr.)**
- **Decommissioning Costs:**
  - One stakeholder provided SEA with decommissioning cost estimates that were atypically high, while a separate stakeholder provided estimates in line with SEA's current inputs
  - SEA also found a study conducted on behalf of Revity Energy regarding a solar facility in Hopkinton RI that estimated decommissioning costs lower than SEA's current inputs
  - **M.I.: No change for Draft 2. SEA to engage stakeholder to better understand driver of atypically high costs quoted**
- **Insurance (% of Project Costs):**
  - One stakeholder provided SEA with insurance cost estimates that were lower than SEA's current inputs
  - Given conflicting feedback, SEA has been unable to conclusively verify if the services provided under such quotes are comparable to those included in SEA's currently adopted inputs
  - **M.I.: No change. SEA to engage stakeholder to better understand scope of services provided under quoted costs**

Hydro Cost Assumptions

- **Insurance (Hydro):**
  - During the 2022 PY CP development process, SEA increased the insurance costs (expressed as a % of total costs) for hydro from 2.7% to 4%
  - In its testimony before the PUC the DPUC opposed this increase and requested that SEA further substantiate the increase
  - In SEA's Draft 1 presentation, we noted a stakeholder provided SEA with insurance costs in excess of 4% of total costs
  - SEA has since clarified the scope of costs included in the quote leading to a revision of the quote to 3.19% of total costs
  - **M.I.: SEA to adjust 2023 PY insurance cost input from 4% to 3.19%**

- **Other Inputs:**
  - SEA received a detailed cost-breakdown of O&M and FERC licensing costs from a stakeholder, and was able to substantiate the scope of costs through further clarification
  - **M.I. SEA to increase numerous hydro O&M and equipment replacement cost inputs (see appendix for details)**

Small Solar I Taxation Assumptions

- During 2022 PY, DPUC raised the question of taxation assumption impacts on the Small Solar I price
- SEA has received data from Rhode Island Energy containing 1,790 months worth of billing information (representing one year of billing and crediting data from customers also selected for REG quality assurance inspections)
    - Based on this sample, the average customer received 52% of their PBI through cash payments (as opposed to bill credits) ➔ assume 52% of PBI is taxable
- LBNL analysis of income of solar adopters ➔ RI adopters' income at 150% of county median
- Using county-level Census data, SEA calculated a household-adjusted median statewide income of $70,812 (which suggests household adopter income is $106,218)
- Using 2022-23 marginal tax rate thresholds from the IRS, SEA calculated that a married couple filing jointly with the above AGI would have an effective tax rate of **14%**
- **M.I.s:**
    - ***Maintain revision of input for % of PBI taxable from prior estimate of 65% ➔ 52%***
    - ***Replace current 26% effective tax rate with 14% effective tax rate***

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Appendix

Summary: Solar <=25 kW Financing Assumptions

	Small I (1-15 kW)			Small II (15-25 kW)		
	2022 Final	***2023 1st Draft***	***2023 2nd Draft***	***2022 Final***	***2023 1st Draft***	***2023 2nd Draft***
Federal Investment Tax Credit (%)	26%	30%	**30%**	26%	30%	**30%**
% Debt	60%	52.5%	**52.5%**	50%	45%	**45%**
Debt Term (years)	13	13	**13**	10	10	**10**
Interest Rate on Term Debt	6.3%	8.4%	**6.3%**	7.0%	9.1%	**7.0%**
Lender's Fee (% of total borrowing)	4.25%	4.25%	**4.25%**	2.3%	2.3%	**2.3%**
Target After-Tax Equity IRR	7%	7%	**7%**	12.5%	12.5%	**12.5%**

Summary: Solar >25 kW Financing Assumptions

	Medium (>25-250 kW)			Comm'l & Comm'l CRDG (>250-1 MW)			Large & Large CRDG (>1 MW-5 MW)		
Assumption Set	***2022 Final***	***2023 1st Draft***	***2023 2nd Draft***	***2022 Final***	***2023 Proposed***	***2023 2nd Draft***	***2022 Final***	***2023 Proposed***	***2023 2nd Draft***
Federal Investment Tax Credit (%)	26%	30%	**30%**	26%	30%	**30%**	26%	30%	**30%**
% Debt	55%	47.5%	**50%**	55%	47.5%	**48%**	52.5%	42.5%	**45%**
Debt Term (years)	15	15	**13**	15	15	**15**	15	15	**15**
Interest Rate on Term Debt	6.6%	8.7%	**6.7%**	5.85%	7.95%	**6.7%**	5.85%	7.95%	**6.8%**
Lender's Fee (% of total borrowing)	1.0%	1.0%	**1.0%**	1.0%	1.0%	**1.0%**	2.0%	2.0%	**2.0%**
% Equity Share of Sponsor Equity	25%	25%	**30%**	25%	25%	**33.3%**	25%	25%	**35%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	13.0%	13.0%	**12.5%**	12.0%	12.0%	**12.0%**	11.0%	11.0%	**11.0%**
% Equity Share of Tax Equity	75%	75%	**70%**	75%	75%	**66.7%**	75%	75%	**65%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	9.5%	**9.5%**	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**	5-Year MACRS	5-Year MACRS	**5-Year MACRS**

Summary: Non-Solar Financing Assumptions

	Wind & Wind CRDG			Hydroelectric			Anaerobic Digestion		
Assumption Set	***2022 Final***	***2023 1st Draft***	***2023 2nd Draft***	***2022 Final***	***2023 1st Draft***	***2023 2nd Draft***	***2022 Final***	***2023 1st Draft***	***2023 2nd Draft***
Federal Investment Tax Credit	0%	30%	**30%**	0%	0%	**0%**	0%	**30%**	**30%**
% Debt	60%	42.5%	**44%**	70%	66%	**70%**	45%	**45%**	**42%**
Debt Term (years)	15	15	**15**	20	20	**20**	15	**15**	**15**
Interest Rate on Term Debt	6.6%	8.7%	**7.0%**	7.15%	9.15%	**7.2%**	6.85%	**8.95%**	**6.8%**
Lender's Fee (% of total borrowing)	1.0%	1.0%	**1.0%**	1.88%	1.88%	**1.88%**	1.5%	**1.5%**	**1.5%**
% Equity Share of Sponsor Equity	60%	25%	**25%**	80%	80%	**80%**	60%	**25%**	**25%**
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	12.0%	12.0%	**12.0%**	12.0%	12.0%	**12.0%**	12.0%	**12.0%**	**12.0%**
% Equity Share of Tax Equity	40%	75%	**75%**	20%	20%	**20%**	40%	**75%**	**75%**
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	9.5%	**9.5%**	9.5%	9.5%	**9.5%**	9.5%	**9.5%**	**9.5%**
Depreciation	Average of 100% bonus and 5-Year MACRS	5-Year MACRS	**5-Year MACRS**	7-year MACRS	7-year MACRS	**7-year MACRS**	5-year MACRS	**5-year MACRS**	**5-year MACRS**

Summary: Solar Cost & Production Assumptions

	Small I	Small II	Medium	Comm'l I	Comm'l I (CRDG)	Comm'l II	Comm'l II (CRDG)	Large	Large CRDG
Nameplate Capacity (kW)	5.8	25	250	500	500	1,000	1,000	5,000	5,000
Capacity Factor	13.4%	13.4%	14.5%	14.6%	14.6%	14.6%	14.6%	15.10%	15.10%
Annual Degradation	1.0%	1.0%	0.8%	0.8%	0.8%	0.8%	0.8%	0.5%	0.5%
Useful Life (Years)	25	25	25	25	25	25	25	30	30
Total Capital Cost ^ ($/kW)	$3,566 [$3,355] [$3,377]	$3,058 [$2,878] [$3,103]	$2,485 [$2,085] [$2,408]	$2,352 [$1,953] [$2,108]	$2,452 [$2,053] [$2,208]	$2,218 [$1,821] [$1,938]	$2,318 [$1,921] [$2,038]	$1,964 [$1,677] [$1,444]	$2,064 [$1,777] [$1,544]
Fixed O&M ($/kW-yr)	$29	$24	$14.57	$12.03	$34.03	$12.03	$34.03	$11.00 [$8.00]	$30.00
O&M Escalation Factor	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.34%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%
Project Management ($/yr)	$0	$0	$3,000	$4,000	$4,000	$4,000	$4,000	$20,000	$20,000
Site Lease ($/yr)	$0	$0	$18,090 [$15,000]	$24,500 [$20,000]	$24,500 [$20,000]	$32,458 [$20,000]	$32,458 [$20,000]	$94,530 [$67,500]	$94,530 [$67,500]

Values in [Purple Brackets] represent 2022 ceiling price inputs, [Blue Bracketed] values are 1st Draft inputs that were changed for the 2nd Draft prices.

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

^ Total cost includes interconnection cost

Summary: Non-Solar Cost & Production Assumptions

	Wind	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	$3,258	$11,918	$11,408
Fixed O&M ($/kW-yr)	$26.50	$48.50	$245 [$2.00]	$600
O&M Inflation	2.0%	2.0%	0% [2.0%]	2.0%
Insurance (% of Cost)	0.29%	0.29%	3.19% [4.0%]	1.5%
Project Management ($/yr)	$18,000	$18,000	$24,000 [$3,000]	$75,000
Property Tax ($/kW)	$5	$5	$5 [$0]	$5
Site Lease ($/yr)	$162,000	$162,000	$8,750	$35,000

1. *Note: For Anaerobic Digestion we use an Availability Factor*
2. Value in [Blue Brackets] are 1st Draft inputs that were changed for the 2nd Draft prices.

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