



Rhode Island REG Program: Final 2026 Program Recommendations

October 27

Sustainable Energy Advantage, LLC

Discussion of Recommended Program Prices



Summary of Changes from September Meeting

- OER has revised its pricing proposal in three primary ways following the September DG Board meeting:
 1. Movement from differentiated Small Solar I Third-Party Owned and Host Owned price → Single Small Solar I Price based on Third-Party Owned project
 2. Revision to Small Solar I Third-Party Owned Price to account for subscriber discount costs
 3. Decision not to pursue updated prices for non-small solar

Small Solar Price Recommendations



Small Solar I Prices – TPO vs Host Owned

- Historically, the REG program has been dominated by host-owned projects for Small Solar
- However, such projects will no longer be eligible for federal tax credits in 2026, while Third-Party Owned projects retain eligibility
- In second draft pricing (presented to DG Board in September), OER presented differentiated prices for Third-Party Owned and Host Owned
- OER has determined that ratepayer costs can be minimized by providing a Small Solar I price that assumes such facilities will qualify for the ITC while such tax benefits are still available → **Adoption of a single Small Solar I price based on Third-Party Owned system**
- **Host-owned projects are still eligible for Small Solar I**, but the price is not calculated assuming host-owned costs and (lack of) federal tax benefits

Recommended Small Solar Prices

- Final proposed Small Solar prices are shown below

Class	Tariff Term	Size Range kW (Modeled Size kW)	2025 Approved Price	2026 1 st Draft Revised Price	2026 2 nd Draft Revised Price	2026 3 rd Draft Revised Price	2026 Final Proposed	% Change (2025→2026)
Small Solar I	15	≤15 (5.8)	33.85	39.45	Host-Owned: 38.35 Third-Party Owned: 28.35	31.75	31.55	-6.8%
Small Solar II	20	>15-25 (25)	32.35	28.05	28.65	28.85	28.65	-11.4%

- In third draft pricing, SEA revised Small Solar I TPO prices to appropriately account for costs associated with providing project hosts with bill discounts
 - Inclusion of such costs is critical to ensure that the adopted price includes sufficient incentives for hosts to accept third-party-owned offerings
 - For non-small solar classes, such payment takes the form of roof/land lease payments, but for residential customers, a bill discount is a more typical compensation structure

Non-Small Solar Price Recommendations



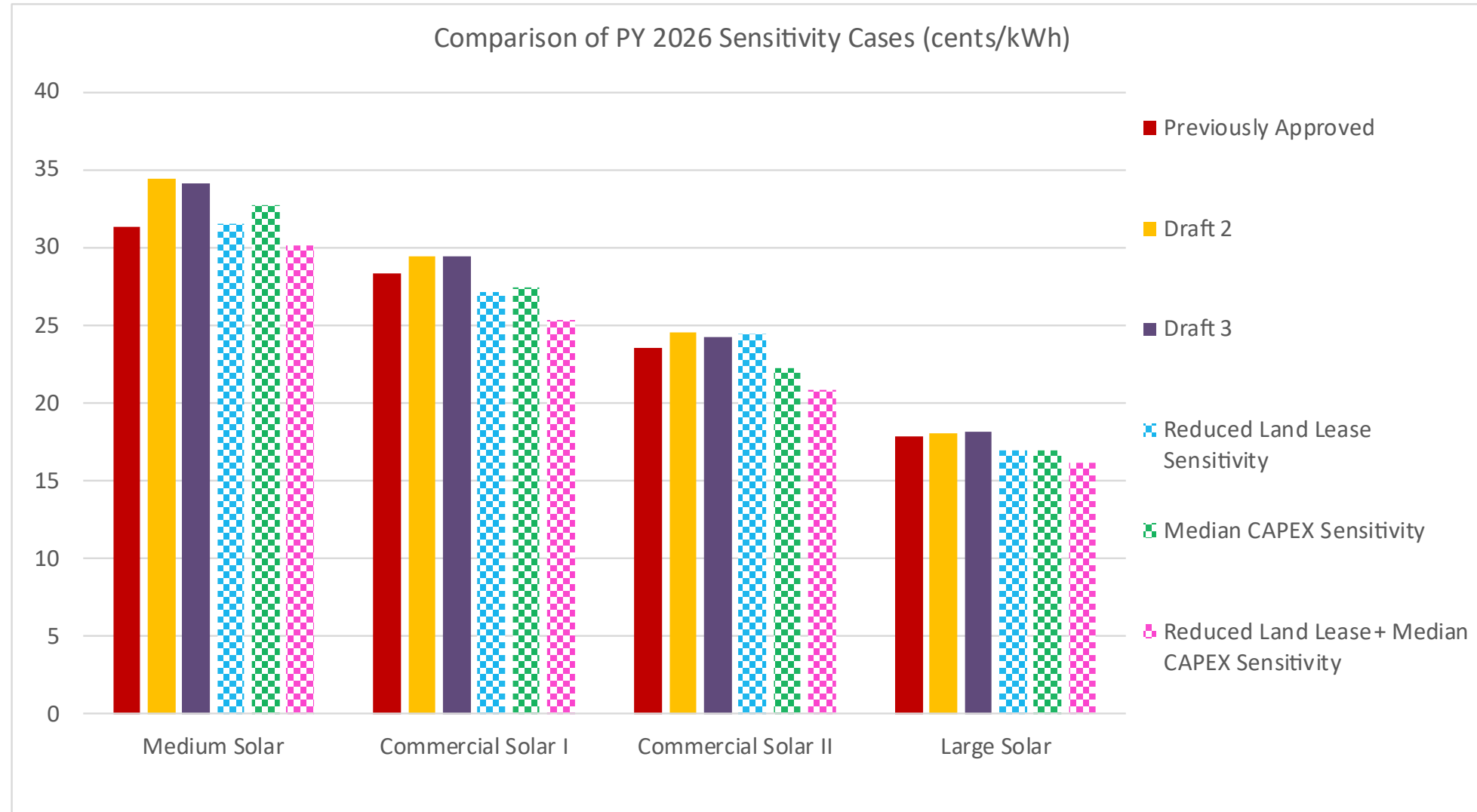
Reasonable Investor Rates of Return (1)

- PUC [Written Order](#) in [Docket 23-44-REG](#) specifies that changes to CPs already approved in the 2024-2026 program plan will require that the requesting party must “provide evidence that the established prices will not result in the statutorily “reasonable rate of return”
- Following the release of second-draft pricing, SEA’s focus turned to assessing the reasonableness of current prices given SEA’s assessment of updated project costs
- SEA assessed the reasonableness of currently-approved ceiling prices by comparing the cost variance introduced by FEOC costs against other typical cost variances

Reasonable Investor Rate of Return (2)

- The following sensitivity cases were explored:

- Third Draft:** Includes reduced Tax Equity IRR
- Reduced Land Lease:** Assumes 25% reduced land lease costs
- Median CAPEX:** Utilizes median installed cost from installed cost databases (vs average of median and 75th percentile)
- Reduced Land Lease + Median CAPEX**



Reasonable Investor Rate of Return (3)

- Sensitivity analysis confirms that current ceiling prices are expected to be workable for a significant segment of the market → **Current ceiling prices result in a “reasonable rate of return” for a sufficient share of the market to justify keeping them in place**
 - Supported by second-draft comments provided by RI Energy
 - In addition, updated modeling results in minimal difference between Third Draft and already-approved CPs for certain classes
 - **Conclusion: OER is not recommending updated 2026 ceiling prices for non-small solar**
- However, SEA maintains that IRR targets should be utilized in future decision-making, especially during the development of a three-year program plan
 - Given that RI is a relatively smaller market with a challenging development environment, sufficiently high returns are needed to keep investors active

MW Allocation Plan



2026 MW Allocation Plan

- The proposed MW Allocation plan differs from the previously presented draft in the following ways:
 - **Small Solar I and II:** Reduced from 6 MW to 3 MW, given reduced program participation in recent years and ratepayer cost concerns
 - **Commercial Solar I and II:** Increased from 7 and 8 MW, respectively, to 9 MW
 - Commercial Solar has had relatively stronger participation in recent enrollments
 - Keeps capacity in classes under 1 MW at 30 MW statutory minimum
 - Results in more capacity subject to competitive bidding
- OER plans to monitor Small Solar I and II enrollment, and may request capacity be re-allocated to such classes if the 3 MW allocation is expected to constrain deployment based on observed enrollment rates
- Consistent with PY 2025, SEA assumes that all Large Solar capacity would be offered in the Third OE
 - Maximizes chances that ASO #4 concludes prior to enrollment

Final Proposed 2026 MW Allocation Plan

Renewable Energy Class	2026 MW Allocation
Large Scale IV (15 - <39MW)	0
Large Scale III (10 - <15MW)	15
Large Scale II (5 - <10MW)	20
Large Scale I (1 - <5MW)	20
Large Scale I - CRDG (1 - <5MW)	5
Commercial Scale II (>500 - <1000kW)	8
Commercial Scale II - CRDG (>500 - <1000kW)	1
Commercial Scale I (>250 - 500kW)	8.5
Commercial Scale I - CRDG (>250 - 500kW)	0.5
Medium Scale (>25 - 250kW)	9
Small Scale II (>15 - 25kW)	3
Small Scale I (0 - 15kW)	3
Wind	3
Wind CRDG	3
Anerobic Digestion	1
Small Scale Hydropower	1
Total	94

REG 2026 PY Benefit-Cost Analysis Results



Overview of Benefit-Cost Analysis (1)

- Consistent with SEA's filing before the PUC during the 2024 and 2025 ceiling price development process, SEA conducted a benefit-cost analysis of the **solar classes** under the proposed program plan
 - Non-solar was not tested given the REG program predominantly focuses on solar
- The analysis utilizes inputs and assumptions from the [2024 Avoided Energy Supply Cost \(AESC\)](#) study
 - The AESC study is conducted once every three years to establish assumptions regarding the benefits of DG and demand-side management/energy efficiency programs
 - Development is overseen by EDCs (including RI Energy), state energy offices and other regulators, and select stakeholders
 - Overall, AESC is accepted as a high-quality source for benefit-cost analysis data, and is currently utilized to assess RI Energy's various energy efficiency programs
- SEA conducted analysis from three perspectives (or "tests"), which are described on the following slides

Overview of Benefit-Cost Analysis (2)

- The total benefits or costs (from either a market value or societal perspective) are the product of:
 - The total capacity assumed to be deployed; and
 - The net present value (NPV) of benefits or REG tariff costs per MW of deployed capacity (including assumed delay from selection to commercial operation)
- SEA also conducted its analysis assuming the following bounded range of benefits and costs:
 - **Assumed high bound:** Full selection and deployment of available capacity in the MW Allocation Plan
 - According to RI Energy data, the full subscription of available capacity AND the 100% attainment of commercial operation by all selected projects has never happened in the history of the REG program
 - In SEA's experience, it is rare (to the point of being functionally unheard of) for a multifaceted portfolio of selected projects in a procurement to **all** reach commercial operation, given many (if not most) projects in development fail to reach critical milestones
 - **Assumed Mid bound:** Assumes 50% of MW allocation comes online
 - Informed by Historical average deployment levels in the program, which are equivalent to 51% of the capacity in the total MW Allocation Plan
 - 51% is equivalent to 78% of the total plan ultimately being selected, and 66% of that population reaching commercial operation
 - SEA notes that this is a conservative assumption of a lower bound given that in recent years selection has been even lower than this historical average
 - **Assumed Low bound:** Assumes 25% of MW allocation comes online
 - **NOTE:** More in line with recent program enrollment
 - **Assumed Lowest bound:** Assumes 10% of MW allocation comes online

BCA Methodology – Rhode Island Test

- First, SEA conducted analysis using the Rhode Island Test (RI Test)
- The PUC adopted the test in Docket 4600, and considers a range of benefits and costs that go beyond those realized by ratepayers
- The test is intended to represent the following:
 - All monetizable energy and capacity benefits; and
 - Benefits associated with avoided GHG emissions; and
 - Reliability benefits
- The RI Test is presented to the Distributed Generation Board both with and without economic development to provide the full range of benefits that the Distributed Generation Board, state agencies and stakeholders may want to consider



BCA Results – Rhode Island Test

Deployment Case	<i>Full Allocation Deployed</i>	<i>50% Allocation Deployed</i>	<i>25% Allocation Deployed</i>	<i>10% Allocation Deployed</i>
MW Assumed Deployed	90	45	22.5	9
Total Benefits (m\$)	\$339.04	\$169.52	\$84.76	\$33.90
Total Cost (m\$)	\$266.21	\$133.11	\$66.55	\$26.62
Net Benefits/Costs (m\$)	\$72.83	\$36.42	\$18.21	\$7.28
Benefit/ Cost Ratio	1.27			

Note: Totals may not equal sum of above components due to rounding



BCA Results – Rhode Island Test + Econ. Dev. Benefits

Deployment Case	<i>Full Allocation Deployed</i>	<i>50% Allocation Deployed</i>	<i>25% Allocation Deployed</i>	<i>10% Allocation Deployed</i>
MW Assumed Deployed	90	45	22.5	9
Total Benefits (m\$)	\$445.04	\$222.52	\$111.26	\$44.50
Total Cost (m\$)	\$266.21	\$133.11	\$66.55	\$26.62
Net Benefits/Costs (m\$)	\$178.83	\$89.42	\$44.71	\$17.88
Benefit/ Cost Ratio	1.67			

Note: Totals may not equal sum of above components due to rounding



BCA Methodology – Cost of Supply Test

- Second, SEA utilized a “Cost of Supply” or “New England Ratepayer” test (previously referred to as the “Market Value Test”)
 - The test considers only benefits and costs that are **monetizable** (e.g., no consideration of non-monetized societal benefits)
 - **No inclusion** of benefits associated with avoided GHG emissions
 - **No inclusion** of reliability benefits (which capture a customer's willingness to pay for uninterrupted service)
 - In prior dockets, the PUC has used this test to determine the excess cost of the REG program
 - Includes benefits associated with energy, capacity, market effects of additional supply
- A benefit/cost ratio (BCR) greater than 1 = the proposal’s cost to New England ratepayers < potentially monetizable benefits



BCA Results – Cost of Supply/New England Ratepayer Test

Deployment Case	<i>Full Allocation Deployed</i>	<i>50% Allocation Deployed</i>	<i>25% Allocation Deployed</i>	<i>10% Allocation Deployed</i>
MW Assumed Deployed	90	45	22.5	9
Total Benefits (m\$)	\$244.74	\$122.37	\$61.18	\$24.47
Total Cost (m\$)	\$266.21	\$133.11	\$66.55	\$26.62
Net Benefits/Costs to NE Ratepayers (m\$)	(\$21.47)	(\$10.74)	(\$5.37)	(\$2.15)
Benefit/ Cost Ratio	0.92			

Note: Totals may not equal sum of above components due to rounding



BCA Methodology – Rhode Island Ratepayer Test

- Third, SEA utilized a “Rhode Island Ratepayer” test
 - The test considers only benefits and costs that are **monetizable** (e.g., no consideration of non-monetized societal benefits) to Rhode Island Ratepayers
 - **No inclusion** of benefits associated with avoided GHG emissions
 - **No inclusion** of reliability benefits (which capture a customer's willingness to pay for uninterrupted service)
 - **No inclusion** of price suppression benefits accruing to neighboring states
- A benefit/cost ratio (BCR) greater than 1 = the proposal’s cost to Rhode Island ratepayers < potentially monetizable benefits



BCA Results – Rhode Island Ratepayer Test

Deployment Case	<i>Full Allocation Deployed</i>	<i>50% Allocation Deployed</i>	<i>25% Allocation Deployed</i>	<i>10% Allocation Deployed</i>
MW Assumed Deployed	90	45	22.5	9
Total Benefits (m\$)	\$166.44	\$83.22	\$41.61	\$16.64
Total Cost (m\$)	\$266.21	\$133.11	\$66.55	\$26.62
Net Benefits/Costs to RI Ratepayers (m\$)	(\$99.78)	(\$49.89)	(\$24.94)	(\$9.98)
Benefit/ Cost Ratio	0.63			

Note: Totals may not equal sum of above components due to rounding



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Appendix A: Discussion of Third Draft Stakeholder Comments



Post-Tariff Revenue (1)

- In its comments, the DPUC and RI Energy argued that the discounting of post-tariff revenues is excessive
 - The DPUC argued the required return on equity takes into account project-specific risks related to pricing and operations
 - RI Energy argued that the adopted AEO 2025 forecast is already conservative (2.1% annual retail rate increase vs. RI Energy historical average of 4.6%)
- Although SEA agrees that the AEO forecasted growth is low relative to historical growth, SEA is concerned that it would be premature to reduce the discount at this stage
 - AEO forecast may inform investor revenue outlooks
 - The cost of reconfiguring a system to comply with net metering regulations is not currently modeled in CREST → discount helps to offset unmodeled costs
 - SEA's prior research findings regarding appropriate discounts, and the need to discount post-tariff revenue to capture risk and uncertainty from an investor perspective still apply
 - There is substantial policy risk that NEM in its current form will not exist in 15-20 years
 - SEA's research suggests that debt providers do not value post-tariff revenue and equity heavily discounts post-tariff revenue as a standard practice
- **Modeling Implication (M.I.): No change, but SEA to consider alternative approaches in the next three-year program plan, including potentially assessing the cost of reconfiguration to net metering**



Post-Tariff Revenue (2)

- RI Energy further argued that the 20% reduction to retail rates to reflect the **HB 5853 / SB 684, An Act Relating To Public Utilities And Carriers - Net Metering**, should not be applied to rooftop facilities, given the law applies to “off-site solar installations”
- Upon review of the statute SEA agrees that application of the 20% haircut to net metering revenue for Small Solar I and II is not supported by statute, as projects subject to reduced rates must be “ground-mounted”
- **M.I.: Remove 20% reduction to modeled post-tariff net metering revenue for Small Solar I and II**

Post-Tariff Revenue (3)

- Lastly, RI Energy requested clarification regarding why the “Residential net metering” rates in column K differed from the “Residential Retail Rate Forecast” in column T of the public CREST model
- Upon further review, SEA can confirm that the values in column T represented an unaltered AEO retail rate forecast, whereas the values in Column K represented the averaged trailing 12-month retail rates specific to RI indexed to the AEO retail rate forecast
- **M.I.: Revise “Residential Retail Rate Forecast” in column T to be consistent with other input set → both inputs use RI-specific values as starting points and index to AEO retail rate forecast**

Post-Tariff Revenue (4)

- Draft 2 Small Solar I Third-Party Owned pricing did not include any costs associated with subscriber discounts provided to compensate the host for leasing their rooftop
 - Inclusion of such costs is critical to ensure that the adopted price includes sufficient incentives for hosts to accept third-party-owned offerings
- In third-draft pricing, SEA included such costs, but only applied such costs to the tariff term
- Upon review, SEA determined it was more appropriate to apply such costs to the useful life of the project, given that hosts are expected to be compensated over the useful life of a project
- **M.I.: Apply subscriber discount costs over the duration of the project useful life, but apply a 40% discount to such costs post-tariff, consistent with the energy value**

Tax Credit Assumptions

- In its comments, RI Energy argued that SEA did not account for the continued availability of tax credit transferability and that transferability provisions should reduce the cost of capital for clean energy developers
- SEA disagrees that transferability was not considered
 - Interviews with developers discussing the applicability of 100% bonus depreciation included consideration of transferability provisions
 - Although not explicitly considered, SEA's updated research on tax equity IRR (which, would implicitly include the influence of transferability on current financing environments), presented in third-draft pricing, suggested that SEA's prior inputs were too high → downward revision of tax equity returns, in line with RI Energy's recommendation
- Given that RI Energy did not present specific evidence that any of the financing inputs assumed by SEA were incorrect, or propose alternatives, it is difficult to evaluate what modeling revision is being requested
- **M.I.: No change. SEA to re-evaluate all inputs, including those potentially impacted by transferability, at the start of the next three-year program proposal**



FEOC Costs

- In its comments, RI Energy argued that SEA's inclusion of FEOC costs is premature and inconsistent with past practice
 - RI Energy argued that, in prior program years, SEA cited "the unavailability of Treasury guidance as an impediment to factoring such provisions into ceiling price assumptions," and FEOC provisions are subject to forthcoming Treasury guidance
- SEA disagrees with RI Energy's characterization
 - In prior program years, there was significant uncertainty regarding if IRA transferability provisions would meaningfully lower project financing → provisions did not have realized cost reductions for projects in development at the time research was being conducted → premature to assume cost reductions
 - In the case of FEOC costs, SEA's research indicated that developers are **currently** experiencing cost increases as a result of FEOC provisions, including:
 - Costs associated with additional legal, contracting, and auditing hurdles
 - Costs associated with the purchase of specialty FEOC insurance
 - Costs associated with re-sourcing equipment
 - Given this, SEA's research concluded that there is minimal uncertainty regarding **if** FEOC requirements would increase costs → uncertainty centered around **what** those costs would be for a given project
- Treasury guidance on FEOC provisions is not required to be published until December 31, 2026 → Waiting until guidance is issued could be impossible in the context of the 2026 PY
- **M.I.: No change.**



Other Comments

- Newport Solar argued that the REG program is not meeting its statutory obligation given persistent low enrollment, that incentive levels are the primary driver of participation, and that the Small Scale I ceiling price should remain at least at 39.45 cents/kWh
- Given the decision to model Small Solar I prices based on a Third-Party Owned system that are able to retain federal tax benefits, a rate of 39.45 cents/kWh is not supported by SEA's modeling
- However, SEA welcomes suggestions regarding specific inputs that should be revised in its modeling during the forthcoming three-year ceiling price process
- **M.I.: No change**

Appendix B: Detailed Non- Small Solar CREST Results



Non-Small Solar - Summary Results (¢/kWh)

- As discussed in this presentation, **OER is not pursuing updated ceiling prices for non-small solar classes in 2026** → Updated CREST results are provided for informational context only

Technology	Tariff Term	Size Range kW (Modeled Size kW)	2026 CP (Approved)	Third Draft CREST Results - 2026 CP	% Change
Medium Solar	20	>25-250 (250)	31.35	34.15	8.9%*
Commercial I	20	>250-500 (500)	28.35	29.45	3.9%
Commercial I CRDG	20	>250-500 (500)	31.25	32.25	3.2%
Commercial II	20	>500-1,000 (1,000)	23.55	24.45	3.8%
Commercial II CRDG	20	>500-1,000 (1,000)	26.35	27.35	3.8%
Large Solar	20	>1,000-5,000 (5,000)	17.85	18.15	1.7%
Large Solar-CRDG	20	>1,000-5,000 (5,000)	20.52	20.85	1.6%
Large Solar II	20	5,000-<10,000 (9,999)	17.25	17.45	1.2%
Large Solar III	20	10,000-<15,000 (14,999)	17.25	17.75	2.9%*
Large Solar IV	20	15,000-<39,000 (20,000)	17.25	17.45	1.2%*
Wind	20	<=5,000 (3,000)	19.85	20.35	2.5%
Wind CRDG	20	<=5,000 (3,000)	21.75	22.25	2.3%

*Note: The % change for these classes does not reflect the change in pure economics from the 2024 process, as the approved CPs for these classes were revised downward by the PUC relative to OER's recommended values to ensure directionally consistent economies of scale → inflates the % change



Appendix C: Detailed Cost, Performance and Financing Assumptions



Summary: Solar ≤25 kW Financing Assumptions

	Small I - Host Owned (1-15 kW)					Small I - TPO (1-15 kW)					Small II (15-25 kW)				
	<i>2025 Adopted</i>	<i>2026 1st Draft</i>	<i>2026 2nd Draft</i>	<i>2026 3rd Draft</i>	<i>2026 Final</i>	<i>2025 Adopted</i>	<i>2026 1st Draft</i>	<i>2026 2nd Draft</i>	<i>2026 3rd Draft</i>	<i>2026 Final</i>	<i>2025 Adopted</i>	<i>2026 1st Draft</i>	<i>2026 2nd Draft</i>	<i>2026 3rd Draft</i>	<i>2026 Final</i>
Federal Investment Tax Credit (%)	30%	0%	0%	0%	N/A	N/A	N/A	30%	30%	30%	30%	30%	30%	30%	30%
% Debt	43.4%	60.1%	60.2%	61.1%	N/A	N/A	N/A	47.0%	43.4%	42.9%	45.2%	45.3%	45.8%	45.9%	45.8%
Debt Term (years)	13	10	10	10	N/A	N/A	N/A	10	10	10	10	10	10	10	10
Interest Rate on Term Debt	6.91%	7.58%	6.96%	6.99%	N/A	N/A	N/A	6.96%	6.99%	6.99%	6.78%	7.58%	6.96%	6.99%	6.99%
Lender's Fee (% of total borrowing)	4.25%	4.25%	4.25%	4.25%	N/A	N/A	N/A	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
Target After-Tax Equity IRR	7%	7%	7%	7%	N/A	N/A	N/A	10.6%	10.1%	10.1%	12.5%	12.5%	12.5%	12.5%	12.5%

Summary: Solar Cost & Production Assumptions

	Small I (Host Owned)	Small I (TPO)	Small II
Nameplate Capacity (kW)	5.8	5.8	25
Capacity Factor	13.4%	13.4%	13.4%
Annual Degradation	1.0%	1.0%	1.0%
Useful Life (Years)	25	25	25
Total Capital Cost (\$/kW)	\$3,539 [\$4,270]	\$3,539	\$3,443 [\$3,942]
Fixed O&M (\$/kW-yr)	\$29	\$29	\$24
O&M Escalation Factor	2.0%	2.0%	2.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.0%
Project Management (\$/yr)	\$0	\$0	\$0
Site Lease (\$/yr)	\$0	\$0	\$0
Property Tax/PILOT (\$/kW)	\$0	\$0	\$5

* Values in [Purple Brackets] represent 2025 ceiling price inputs

Summary: Revised Non-Small Solar Assumptions

	Total Capital Costs (\$/kW)	Interest Rate	Target After-Tax Equity IRR	% Debt
Medium Solar	\$3,254 [\$2,971]	7.11% [6.95%]	10.1% [10.5%]	47.50%
Commercial Solar I	\$2,994 [\$2,779]	7.11% [6.95%]	10.0% [10.3%]	47.10%
Commercial Solar I CRDG	\$3,094 [\$2,879]	7.11% [6.95%]	10.0% [10.3%]	47.40%
Commercial Solar II	\$2,728 [\$2,588]	7.11% [6.95%]	10.0% [10.3%]	46.50%
Commercial Solar II CRDG	\$2,828 [\$2,688]	7.11% [6.95%]	10.0% [10.3%]	46.50%
Large Solar	\$2,414 [\$2,328]	7.20% [7.03%]	9.6% [10%]	45.20%
Large Solar CRDG	\$2,514 [\$2,428]	7.17% [7.03%]	9.6% [10%]	45.20%
Large Solar II	\$2,113 [\$2,109]	7.20% [7.03%]	9.6% [10%]	50.50%
Large Solar III	\$2,027 [\$2,021]	7.20% [7.03%]	9.6% [10%]	54.50%
Large Solar IV	\$1,981 [\$1,973]	7.20% [7.03%]	9.6% [10%]	54.60%
Large Wind	\$3,648 [\$3,548]	7.45% [7.25%]	9.75% [10.1%]	42.80%
Large Wind CRDG	\$3,748 [\$3,648]	7.45% [7.25%]	9.75% [10.1%]	42.80%

- Values in **[Purple Brackets]** represent previously approved 2026 ceiling price inputs
- For all other CP inputs, see Appendix A of [2024-2026 Program Year Ceiling Price Recommendations](#)

Appendix D: Detailed Capital Cost Data for Solar Projects



Small Solar I Installed Cost Summary Statistics

Small Solar I, Installed Costs											
0-15 kW											
Time Period		2024 (Full Year)						2025 (Partial Year)			
Dataset	Sample Size	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	N	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	
MA SMART (Qualified & Operational)	156	\$4,007	\$3,786	\$3,287	\$4,425	11	\$3,339	\$3,009	\$2,855	\$3,574	
CT RRES	9,703	\$3,865	\$3,854	\$3,352	\$4,336	4,592	\$3,765	\$3,752	\$3,240	\$4,229	
CT CGB ESS	123	\$3,592	\$3,723	\$3,098	\$4,019	93	\$3,294	\$3,170	\$2,995	\$3,371	
NY - NYSERDA Solar Electric Programs	12,985	\$3,967	\$3,769	\$3,108	\$4,607	5,316	\$4,132	\$3,944	\$3,273	\$4,800	
RI Small Scale REG	78	\$4,216	\$4,179	\$2,979	\$5,333	21	\$3,353	\$2,510	\$2,034	\$4,917	
RI REF	150	\$4,542	\$4,080	\$3,622	\$5,467	46	\$3,827	\$3,573	\$3,190	\$4,097	
Energy Sage - RI Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - MA Accepted Bids*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - NY Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - CT Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - ME Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage Accepted Averages	N/A	\$3,062	\$3,008	\$2,917	\$3,164	N/A	\$2,911	\$2,855	\$2,788	\$2,985	
LBNL Tracking the Sun Advance Dataset RI	299	\$4,360	\$3,966	\$3,498	\$5,055	N/A	No Data	No Data	No Data	No Data	
LBNL TTS - All NE States	18,976	\$4,480	\$4,140	\$3,278	\$5,350	N/A	No Data	No Data	No Data	No Data	

*NOTE: SEA has withheld the state-specific summary statistics, since these values represent the output of non-public datasets that are normally provided for a fee that were generously provided to SEA by EnergySage specifically for this analysis.

Small Solar II Installed Cost Summary Statistics

Small Solar II, Installed Costs											
15-25 kW											
Time Period		2024 (Full Year)						2025 (Partial Year)			
Dataset	Sample Size	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	N	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	
MA SMART (Qualified & Operational)	61	\$3,371	\$3,349	\$2,680	\$3,741	2**	\$3,517	\$3,517	\$3,253	\$3,781	
CT RRES	1,087	\$3,538	\$3,544	\$2,989	\$4,100	696	\$3,399	\$3,368	\$2,899	\$3,909	
CT CGB ESS	34	\$3,664	\$3,664	\$3,065	\$3,907	18	\$3,245	\$3,199	\$2,954	\$3,571	
NY - NYSERDA Solar Electric Programs	1,354	\$3,378	\$3,185	\$2,773	\$3,719	618	\$3,385	\$3,115	\$2,800	\$3,809	
RI Small Scale REG	3***	\$4,336	\$4,965	\$3,839	\$5,147	N/A	No Data	No Data	No Data	No Data	
RI REF	21	\$3,624	\$3,370	\$3,017	\$3,923	13	\$3,406	\$3,350	\$3,188	\$3,729	
Energy Sage - RI Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - MA Accepted Bids*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - NY Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - CT Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage - ME Accepted*	N/A	Withheld	Withheld	Withheld	Withheld	N/A	Withheld	Withheld	Withheld	Withheld	
EnergySage Accepted Averages	N/A	\$2,802	\$2,814	\$2,708	\$2,891	N/A	\$2,795	\$2,787	\$2,742	\$2,831	
LBNL Tracking the Sun Advance Dataset RI	17	\$3,569	\$3,496	\$3,017	\$3,796	N/A	No Data	No Data	No Data	No Data	
LBNL TTS - All NE States	2,527	\$3,527	\$3,265	\$2,800	\$4,000	N/A	No Data	No Data	No Data	No Data	

*SEA has withheld the state-specific summary statistics, since these values represent the output of non-public datasets that are normally provided for a fee that were generously provided to SEA by EnergySage specifically for this analysis.

**Excluded from analysis due to small sample size

***Averaged with 2024 RI REF due to small sample size

Medium Solar Installed Cost Summary Statistics

Medium Solar, Installed Costs											
>25-250 kW											
Time Period		2024 (Full Year)						2025 (Partial Year)			
Dataset	Sample Size	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	N	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	
MA SMART (Qualified & Operational)	86	\$2,908	\$2,571	\$2,225	\$3,392	9	\$2,152	\$2,145	\$2,021	\$2,175	
CT Residential Renewable Energy Solutions	35	\$3,501	\$3,512	\$2,912	\$3,838	N/A	No Data	No Data	No Data	No Data	
NY - NYSEDA Solar Electric Programs	412	\$3,371	\$3,200	\$2,672	\$3,776	172	\$3,316	\$3,149	\$2,582	\$3,807	
CT NRES	195	\$2,822	\$2,706	\$2,375	\$3,062	N/A	No Data	No Data	No Data	No Data	
RI REG	23	\$2,648	\$2,554	\$2,460	\$3,001	4	\$2,845	\$2,687	\$2,559	\$3,290	
RI REF	19	\$3,238	\$3,150	\$2,650	\$3,700	12	\$3,144	\$3,040	\$2,405	\$3,418	
LBNL Tracking the Sun Advance Dataset RI	14	\$3,271	\$3,352	\$2,814	\$3,549	N/A	No Data	No Data	No Data	No Data	
LBNL TTS - All NE States	586	\$3,215	\$2,997	\$2,454	\$3,600	N/A	No Data	No Data	No Data	No Data	

Commercial Solar Installed Cost Summary Statistics

Commercial Solar, Installed Costs											
>250-1 MW											
Time Period		2024 (Full Year)						2025 (Partial Year)			
Dataset	Sample Size	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	N	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	
MA SMART (Qualified & Operational)	19	\$3,063	\$2,668	\$2,102	\$3,948	N/A	No Data	No Data	No Data	No Data	
NY - NYSERDA Solar Electric Programs	43	\$2,148	\$2,130	\$1,892	\$2,455	30	\$2,633	\$2,240	\$2,031	\$2,813	
CT NRES	7	\$2,546	\$2,259	\$2,066	\$2,750	N/A	No Data	No Data	No Data	No Data	
RI REG	7	\$3,644	\$3,648	\$3,248	\$4,012	N/A	No Data	No Data	No Data	No Data	
LBNL Tracking the Sun Advance Dataset RI	N/A	N/A	N/A	N/A	N/A	N/A	No Data	No Data	No Data	No Data	
LBNL TTS - All NE States	104	\$2,469	\$2,265	\$1,999	\$2,793	N/A	No Data	No Data	No Data	No Data	

Large Solar Installed Cost Summary Statistics

Large Solar, Installed Costs										
1-5+ MW										
Time Period		2024 (Full Year)					2025 (Partial Year)			
Dataset	Sample Size	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)	N	Average (\$/kW)	Median (\$/kW)	25th Percentile (\$/kW)	75th Percentile (\$/kW)
MA SMART (Qualified & Operational)	2	\$1,746	\$1,746	\$1,693	\$1,799	N/A	No Data	No Data	No Data	No Data
NY - NYSERDA Solar Electric Programs	28	\$1,919	\$1,735	\$1,641	\$2,158	9	\$1,964	\$1,720	\$1,660	\$2,038
CT NRES	27	\$2,335	\$2,255	\$2,034	\$2,683	N/A	No Data	No Data	No Data	No Data
RI REG	1	\$2,275	\$2,275	N/A	N/A	N/A	No Data	No Data	No Data	No Data
LBNL Tracking the Sun Advance Dataset RI	N/A	No Data	No Data	No Data	No Data	N/A	No Data	No Data	No Data	No Data
LBNL TTS - All NE States	34	\$2,050	\$1,895	\$1,507	\$2,495	N/A	No Data	No Data	No Data	No Data

Solar Cost Adjustments

- The following costs are added onto the “base” costs derived through state databases (all in \$/kW)

IC Cost Adder	IC Cost Adj.	Meter Relocation Adj.	Prevailing Wage Adj.	Electrician Labor Adj.	FEOC Compliance Adj.
Small Solar I	N/A	N/A	N/A	\$26**	\$150 (TPO Only)
Small Solar II	N/A	N/A	N/A	\$28**	\$150
Medium Solar	N/A	\$65*	N/A	\$25**	\$150
Commercial Solar I	N/A	\$33*	N/A	\$30	\$150
Commercial Solar II	N/A	N/A	N/A	\$30	\$150
Large Solar I	\$263	N/A	N/A***	\$30	\$100

*Adjusted downward from the full value of \$120 for Medium and \$65 for Commercial I, as 5 of 11 data sources contributing to CAPEX estimates are RI-specific, and are assumed to contain such costs already

**Adjusted downward from full value of \$30 to reflect share of databases reflecting RI-specific 2025 costs, which are assumed to include cost adj already

*** Removed given majority of projects in installed cost databases assumed to comply in 2024/2025

