Solar Massachusetts Renewable Target (SMART) Programmatic Review

Task 1 Final Report: Evaluation of Solar Costs and Needed Incentive Levels across Sectors from 2025-2030

Prepared by Jim Kennerly, Cal Brown, Tobin Armstrong, Jacob Nichols, and Tom Michelman of Sustainable Energy Advantage, LLC (SEA) for the Massachusetts Department of Energy Resources

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Glossary of Acronyms

- AOBC- Alternative On Bill Credit
- ATB- Annual Technology Baseline
- BCR- Base Compensation Rate
- BOS- Balance of system
- C&I- Commercial and industrial
- CapEx- Capital expenditure
- CEIC- Clean Energy Investment Credit
- CIP- Capital Improvement Project
- CREST- Cost of Renewable Energy Spreadsheet Tool
- CSS- Community Shared Solar
- DO- Direct owned
- DOER- Massachusetts Department of Energy Resources
- DSCR- Debt service coverage ratio
- DPU- Department of Public Utilities
- EDC- Electric distribution company
- ESS- Energy storage system
- IRA- Inflation Reduction Act of 2022
- IRR – Internal rate of return
- ITC- Investment Tax Credit
- LCOE- Levelized cost of energy
- LICSS- Low-Income Community Solar
- LIPS- Low-Income Property Solar
- LIS- Low-Income Solar
- NREL- National Renewable Energy Laboratory
- NPV- Net present value
- O&M- operations and maintenance
- OpEx- operational expenditure
- PV- Photovoltaic
- SEA- Sustainable Energy Advantage, LLC
- SMART- Solar Massachusetts Renewable Target program
- T&D- Transmission and distribution
- TPO- Third-party owned
- VOE- Value of Energy

Introduction: How Did We Get Here? A Brief History of Distributed Solar and Storage in Massachusetts

The World Before Late 2019: Macroeconomic Conditions & Market Fundamentals for MA Distributed Solar in the 2010s

- In 2010, DOER established the 400 MW Solar Carve-Out (known by many as SREC I) to the Class I Renewable Portfolio Standard. By 2013, DOER created the 1,600 MW Solar Carve-Out II (known by many as SREC II)– the first program to establish many of the market sectors included in the present SMART program.
- By 2016, the 1,600 MW in SREC II was exhausted, at which time DOER extended SREC II while it considered the development of a successor program, which would eventually become the declining-block incentive-based Solar Massachusetts Renewable Target (SMART) program.
- By the late 2018 opening of the 1,600 MW SMART program (and closing of SREC II), the relative delay in approval of the program following the proposal of emergency regulations in mid-2017, as well as the fact that compensation rates were based in significant part upon 2016-2017 economics, led to much of the capacity in the program being secured by entities seeking qualifications for their projects very quickly.
- As a result of this rapid qualification of the available capacity in the SMART Program, during late 2018 and 2019, DOER developed plans for a second 1,600 MW tranche of program capacity, which were ultimately proposed and approved in 2020 and 2021, respectively.
- Thus, in mid-2019, nearing the close of the 2010s, the cost of solar PV projects in New England – though elevated relative to the rest of the country – had experienced a decade-long, uninterrupted 10-year period of decline.
- At that time, there was little evidence to suggest this would change – but change it did.

Macroeconomic/Market Fundamentals of Distributed Solar/Storage in Massachusetts: Late 2019 and Thereafter (1)

- During the latter half of 2019, it became clear that the large influx of SMART projects (particularly those not associated with an on-site load in various parts of the Commonwealth), when layered upon already-operating SREC I and II projects, would require extremely significant and costly distribution and transmission system modifications and upgrades.
- As 2019 turned to 2020 and the years thereafter, it became very clear that interconnection costs would not return to the pre-SMART norm and would instead continue to grow and reach levels that, in the absence of major changes to interconnection cost allocation, would be unaffordable if fully assigned to project developers. As a result, and following processes to determine an approach to the development of Capital Improvement Projects (CIPs) in designated areas of the EDCs' territories, the relative cost of interconnection became more broadly stabilized, though at a rate well beyond the pre-2020s norm.
- In response to the COVID-19 pandemic, which began to affect the world at large in Spring 2020, governments and central banks around the world utilized extraordinary fiscal and monetary stimulus measures in order limit the damage of sharp drops in economic activity. The results of these extraordinary actions led to record injections of (relatively) cheap money into the money supply at near-zero interest rates.
- When paired with the stop/start nature of the public health response to the pandemic around the world, this injection of money into the money supply exacerbated a historic misalignment of demand for goods necessary for project development in the solar industry relative to their supply and availability. The unprecedented inflation (and substantial delays) led to shortages for (and unprecedented spikes in the cost of) critical materials, components and labor for solar PV and energy storage projects.

Macroeconomic/Market Fundamentals of Distributed Solar/Storage in Massachusetts: Late 2019 and Thereafter (2)

- During early 2022, while the impacts of this inflation were broadly rippling through the solar industry writ large, the Russian invasion of Ukraine led to a realignment of the economics of natural gas markets in the United States, for which it assumed the role of swing producer and exporter to the Western world, and away from Russia. The main impact of this for the Massachusetts solar and storage markets, however, was a sharp rise in retail rates for electric service.
- Though P.L. 117-169 - Inflation Reduction Act of 2022 ("the IRA") provided for unprecedented incentives for solar PV and energy storage projects and their supply chain, the primary response to this inflation was a large increase in interest rates by central banks worldwide. Furthermore, the IRA also requires paying local Davis-Bacon prevailing wages to receive the full value of the tax credits, which requires increases in installed capital costs to address this increase in the cost of installation labor.
- The increase in interest rates, as well as new prevailing wage requirements, led to another wave of cost increases for SMART-eligible projects, for which the incentive provisions for distributed energy projects in the IRA simply could not fully compensate for.
- Overall, the product of all these factors has become clear: **there is now a historic and structural misalignment between the cost of project development, which resides in the here-and-now of the post-COVID world – while SMART program incentives continue to reflect a pre-COVID outlook for the solar PV and energy storage industries.**
- A significant impact of this misalignment has been, for some market sectors, the creation of a vicious cycle in which an explosion in the development of projects strictly utilizing retail and/or net metering compensation enabled by the sharp increases in rates following the invasion of Ukraine eliminates the gap between values of energy (VOEs) and SMART incentive caps, leading to more utilization of net metering, and less utilization of the SMART program, which is intended to balance the cost of distributed energy to ratepayers. For other market sectors – including those in which development is targeted to preferred sites, such as disturbed parcels of land – the pace of projects reaching commercial operation has, in many cases, come to nearly a full halt.

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Overview of SMART Programmatic Review and Summary of Task 1 Scope

Overview of Analyses Requested by DOER

- To determine the nature of the present misalignment between SMART program compensation levels and current solar PV and energy storage costs, DOER has engaged Sustainable Energy Advantage, LLC (SEA) to conduct two main analytical tasks:
  - Task 1: Evaluation of Solar Costs and Needed Incentive Levels Across Sectors from 2025-2030
  - Task 2: Evaluation of Potential SMART Program Improvements
- SEA's Task 1 analysis and support to DOER involved the following activities:
  - The issuance of a Data Request and Survey to Massachusetts solar PV and energy storage market participants regarding current cost, performance and financing assumptions for projects eligible for the program;
  - The development of a methodology to synthesize the survey responses into estimates of inputs to an analysis of the current costs of solar PV and energy storage in Massachusetts, as well as trajectories of said cost, performance and financing assumptions from 2025 through 2030;
  - Modeling (utilizing SEA's Cost of Renewable Energy Spreadsheet Tool (CREST)) the levelized base revenue requirements for projects ≤ 25 kW_{AC}, 25-250 kW_{AC} , 250-500 kW_{AC} , 500 kW_{AC} -1 MW_{AC}, and >1 MW_{AC} (up to 5 MW_{AC});
  - Modeling the levelized incremental revenue requirements of projects in the Community Shared Solar, Low-Income Community Shared Solar, Low-Income Property Solar, Landfill, Brownfield, Solar Canopy, Rooftop Solar, Dual Use Agricultural, and Solar + Storage market segments; and
  - The incorporation of elements introduced by the IRA, including elective payment for non-taxable entities, the allowance to count interconnection costs in a project's basis for the Investment Tax Credit (ITC), bonus credits available under the existing Section 48 ITC, as well as the extension and creation of a successor Clean Energy Investment Credit under Section 48E of the Internal Revenue Code.

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Data Request to (and Survey of) SMART Market Participants

Data Request and Survey Process/Approach (1)

- SEA, with input from DOER throughout the process, fielded a survey of market participants to collect data on solar and storage costs to better inform modeling inputs with up-to-date, Massachusetts-specific costs.
- To select an initial subset of market participants to distribute the survey to, SEA analyzed the Qualified SMART Solar Tariff Generation Units list, and identified the top 10 developers, as measured in total MW qualified, for each projects size, and for the offtaker and location-based adders (there was some overlap, and several developers were in the top 10 for different sizes and adder categories).
- SEA also utilized solar and storage industry organization channels to solicit participation from any other interested stakeholder.
- Where requested, SEA provided orientations and question-and-answer sessions to individual stakeholders on how to complete the survey elements.
- The survey included both a quantitative Excel cost component for bottom-up modeling, as well as a qualitative questionnaire about MA-specific costs and stakeholder involvement in the MA solar and storage market.

Data Request and Survey Process/Approach (2)

- The quantitative survey requested Massachusetts-specific costs for each of the current SMART size categories and project configurations that are supported by specific program elements (as noted above on slide 8).
- The survey requested project-level data by the following categories:
  - Interconnection Costs
  - PV System Production
  - Solar PV Capital Costs
  - Solar PV Operating Expenses
  - Incremental ESS Non-Interconnection Capital Costs
  - Incremental ESS Fixed O&M Costs
  - Capital Equipment Replacement Costs
  - Financing Information
  - 3rd Party v Host Owned Differences

Data Request and Survey Process/Approach (3)

- SEA received 18 total quantitative survey stakeholder responses, and in total, 24 stakeholders responded to the qualitative survey.
- Overall, SEA received some survey input from 45% of stakeholders who were provided with the survey.
- To avoid skewing results, stakeholders were asked to only provide data on project sizes and types where they have significant experience.

Adder Category Responses	Total Respondents by Sector	Total In Top 10 Market Share by Category
Brownfield	5	2
Community Shared Solar	6	3
Landfill	5	2
Solar Canopy	11	5
Rooftop Solar	14	7
Dual-Use Agricultural	5	3
Low-Income Community Solar	4	1
Low-Income Property Solar	4	1
Low-Income Solar	1	0
Solar + Storage	11	8

Data Request and Survey Process/Approach (4)

- SEA collected responses, quality-controlled the data, and contacted stakeholders for further clarification where necessary.
- SEA then used the survey responses to help derive CREST model inputs relating to project cost, performance, and financing (see methodology section for more detail).
- The inputs used for CREST modeling were heavily influenced by the survey responses, supplemented with data collected by the SEA team from regional sources.

Size category (AC)	Total Ground Mounted Solar Respondents	Total Top 10 Ground Mount Capital Cost respondents
<= 25 kW	2	1
25 – 250 kW	2	2
250-500 KW	4	2
500- 1 MW	6	2
1-5 MW	8	4

NOTE: In calculating the number of respondents, SEA counted the number of capital cost respondents, as capital costs are the single largest factor driving overall costs. Some stakeholders, however, provided information on size categories or adder categories, such as capacity factors or operational expenses, but not capital costs.

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Calculating Solar PV and Solar + Storage Revenue Requirements: Modeling Approach, Inputs and Assumptions

Modeling Process Overview

- SEA utilized a Massachusetts-customized version of the Cost of Renewable Energy Spreadsheet Tool (CREST) Model (a tool Sustainable Energy Advantage, LLC developed for the National Renewable Energy Laboratory (NREL)).
- The purpose of the MA SMART version of CREST is to establish revenue requirements (on a levelized cost of energy basis) for existing SMART solar project resource blocks closing financing from 2025-2030.
- Standard (and customized) modeled inputs in MA CREST include:
  - Capacity Factor and Production Degradation (by project type);
  - Installed Costs;
  - Financing Costs (interest on term debt, debt tenor, % of debt, after-tax equity IRR, development and fees (if not captured in equity return));
  - O&M Costs;
  - Project Management Costs;
  - Land Lease; and
  - Incremental operating and CapEx costs for certain project types (e.g., brownfield, rooftop, low income, community solar, canopy).

Simplified Representation of CREST Calculation of Project Revenue Requirement

Net Present Value (NPV)/ Discounted Cash Flows Resulting From:

PV Total Capital and Operating Costs (Various)

Compounded/Grossed-Up by…

Risk-Adjusted Financing Costs & Taxes (Various Terms)

LESS…

Expected Federal Tax & Depreciation Benefits During and After Incentive Term

All Divided By…

PV Performance over Useful Life (MWh) derived from Degradation-Adjusted Capacity Factor

Put it all together and you get…

Revenue Requirement/ LCOE by Resource Block ($/MWh)

Inputs Development and Modeling Methods

- SEA utilized the survey response data to derive the inputs for the CREST model.
- To provide a range of possible resource costs, SEA varied certain key inputs to produce high/base/low-cost cases:
  - Solar capital cost inputs were varied as follows (specific values provided on Slide 21)
    - High Costs – average of median and 75th percentile costs
    - Base - 50th percentile costs
    - Low - average of the median and the 25th percentile costs
  - The high- and low-cost cases also vary Capacity Factors +/- 2.5% (relative)
- SEA used 2023 as the reference year and projected future solar capital costs using the [2023 NREL Annual Technology Baseline] (ATB) conservative cost case.
  - While solar and storage costs have recently and sharply increased due to global events, the ATB projects moderate cost declines going forward.
- SEA used an internal forecast of storage capital costs to project future storage capital costs.
  - Cost declines for storage are projected to be steeper than solar, due to the relative maturity of the technology.

PV Cost/Performance Inputs and Modeling Methods (1)

- Specific PV cost and performance inputs, by size bin, are provided below and on the next slide.
- These "base" inputs may be transformed or added to based on specific project characteristics (e.g., siting, offtakers), as described on the following slides.
- Note that all ≤ 25 kW_{AC} projects are assumed to be rooftop mounted. As such, certain incremental costs are assumed to be zero.

Component	≤ 25 kW_{AC} (Residential)	≤ 25 kW_{AC} (Small C&I)	>25-250 kW_{AC}	>250-500 kW_{AC}	>500 kW-1.0 MW_{AC}	>1-5 MW_{AC}
Nameplate Capacity (kW_{DC})	7.7	27.5	275	600	1300	6500
Capacity Factor	12.34%	12.34%	13.63% (13.12%)	13.63% (13.17%)	13.82% (13.35%)	14.37%
Annual Degradation	1.00%	1.00%	0.80%	0.80%	0.80%	0.50%
Useful Life (Years)	20	20	20	20	20	20
Total Installed Cost ($/kW)	$4,530	$4,012	$2,890 ($3,222)	$2,674 ($2,850)	$2,504 ($2,755)	$2,229
Inverter Replacement (Year)	12	12	12	12	12	12
Inverter Replacement Cost ($/kW)	$185.00	$185.00	$74.06	$74.06	$74.06	$74.06

Purple = Alternate "base" inputs for C&I Rooftop projects provided inside "()"

PV Cost/Performance Inputs and Modeling Methods (2)

Component	≤ 25 kW_{AC} (Residential)	≤ 25 kW_{AC} (Small C&I)	>25-250 kW_{AC}	>250-500 kW_{AC}	>500 kW-1.0 MW_{AC}	>1-5 MW_{AC}
Fixed O&M ($/kW-yr)	$29	$24	$14	$12	$12	$11
O&M Escalation Factor	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation Factor	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	---	---	0.3429%	0.5715%	0.5715%	0.5715%
Project Management ($/yr)	---	---	$3,406	$4,688	$5,750	$18,292
Site Lease ($/yr)	---	---	$16,500	$21,500	$22,500	$81,750
Property Taxes ($/yr)	---	---	$3,050	$5,450	$12,800	$49,750

PV Cost/Performance Inputs and Modeling Methods (3)

- Base inputs are altered based on specific project characteristics, as follows

Component	Adjustment	Offtaker-based Adjustors				Siting-based Adjustors					
		Community Shared Solar (CSS)	Low-Income Community Shared Solar (LICSS)	Low-Income Property Solar (LIPS)	Low-Income Solar (LIS)	Residential Rooftop	C&I Rooftop	Brownfield	Landfill	Canopy	Dual-use Agricultural
Capacity Factor	*Relative % change*	N/A	N/A	N/A	N/A	N/A	N/A	**-2.50%**	**-5.00%**	**-5.01%**	**-3.77%**
Total Installed Cost	*Incremental Installed Cost*	**$179.4/kW**	**$414.8/kW**	**$717.5/kW**	**$250.0/kW**	N/A	N/A	**$286.4/kW**	**$310.9/kW**	**$1,129.6/kW**	**$1,095.4/kW**
Fixed O&M	*Varies*	**+$22.0/kW-yr**	**+$28.6/kW-yr**	**+18.0%**	N/A	**+15.0%**	**+15.0%**	**+14.5%**	**+19.2%**	**+20.0%**	**+40.1%**
Insurance	*Relative % change*	N/A	N/A	N/A	N/A	N/A	**+10%**	**+15%**	**+10%**	**+5%**	N/A
Project Management	*Relative % change*	N/A	N/A	N/A	N/A	N/A	N/A	**+7%**	**+10%**	N/A	N/A
Site Lease	*Relative % change*	N/A	**-2.39%**	**-13.1%**	N/A	N/A	N/A	N/A	**+87.7%**	**-27.1%**	**-12.7%**

PV Cost/Performance Inputs and Modeling Methods (4)

- Inputs are also altered by cost case, as follows.
- Please note that the below inputs are varied together (i.e., the high-cost case uses the high total installed cost input *and* adjusts the capacity factor downward).

Resource Size Bin	Total Installed Cost ($/kW$_{DC}$) *(Alternate "base" input)*			Capacity Factor *(Relative % change)*		
	Base Case	High Case	Low Case	Base Case	High Case	Low Case
≤ 25 kW$_{AC}$ (Residential)	$4,530	$4,920	$4,180	N/A	**-2.5%**	**+2.5%**
≤ 25 kW$_{AC}$ (Small C&I)	$4,012	$4,135	$3,897	N/A	**-2.5%**	**+2.5%**
>25-250 kW$_{AC}$	$2,890 ($3,222)	$3,100 ($3,366)	$2,650 ($3,076)	N/A	**-2.5%**	**+2.5%**
>250-500 kW$_{AC}$	$2,674 ($2,850)	$2,791 ($3,056)	$2,591 ($2,679)	N/A	**-2.5%**	**+2.5%**
>500 kW-1.0 MW$_{AC}$	$2,504 ($2,755)	$2,627 ($2,793)	$2,423 ($2,628)	N/A	**-2.5%**	**+2.5%**
>1-5 MW$_{AC}$	$2,229	$2,383	$2,089	N/A	**-2.5%**	**+2.5%**

Purple = Alternate "base" inputs for C&I Rooftop projects provided inside "()"

Storage Cost/Performance Inputs and Modeling Methods

- SEA analyzed paired storage using varying assumptions for the size (as % of PV system capacity) and duration (in hours).
- SEA applies certain adjustments to PV+ESS systems to account for the net impact of round-trip efficiency losses, versus capturing clipped energy.
  - ≤ 25 kW_{AC} = 99.4% of standalone kWh
  - > 25 kW_{AC} = 100.1% of standalone kWh
- SEA assumes **battery replacement at year 14**, with a **cost of 49% of initial capital expenditure** (based on expected cost declines after COD and partial replacement of initial equipment).
- SEA assumes **storage O&M costs are $9/kWh.**
- Specific storage capital cost inputs are provided in the table right.

Storage Size (kWh)	Installed Cost ($/kWh)
3.5 - 12.5	$1,150.0
25	$1,110.0
50	$992.5
100 - 125	$875.0
250	$806.3
500	$722.9
1,000	$684.1
2,000	$596.0
2,500	$499.5
4,000	$470.8
5,000	$456.4
10,000	$441.9
20,000	$424.6

Financing/Tax Inputs and Modeling Methods (1)

- All projects assumed to have the one of the following ownership/taxability configurations:
  - Third party owned (TPO) and taxable (e.g., projects by corporate developers);
  - Direct owned (DO) and taxable (e.g., small C&I rooftop projects); and
  - Direct owned (DO) and non-taxable (e.g., municipal projects).
- Owners of taxable TPO and DO projects are assumed to pay state and federal individual or corporate income taxes, depending on their owner’s status as a taxpayer.
- **Projects assumed eligible under federal tax code provisions** related to the Investment Tax Credit (ITC) for projects that either begin construction prior to 12/31/2024, as well as the availability of the successor Clean Energy Investment Credit (CEIC) for projects that are placed in service no earlier than January 1, 2025 (therefore rendering “safe harboring” irrelevant to this analysis).

Financing/Tax Inputs and Modeling Methods (2)

- The two tax credits have **functionally identical statutory provisions**, including:
  - A full tax credit value of 30%.
  - Bonus credits ranging from 10% (for projects sited on brownfields or other "energy communities" or in "low income or disadvantaged communities") to 20% (for projects serving low-income offtakers).
  - The ability to include the cost of transmission and/or distribution system modifications in the project's tax basis for calculating the value of either type of investment credit.
  - The ability to transfer tax credits.
- Given increasing project delays (which make it impossible to claim bonus depreciation under existing Tax Cuts and Jobs Act of 2017 provisions phasing out bonus depreciation for projects placed in service no later than the end of 2026) **we assume projects can only monetize 5-year MACRS depreciation (and cannot monetize bonus depreciation).**

Financing/Tax Inputs and Modeling Methods (3)

- Debt shares held constant over the analysis term and sized to meet an average debt service coverage ratio (DSCR) of 1.30 (for non-LI/CSS projects) and 1.35 (for LI/CSS projects).
- Debt terms vary based on project size.
- Interest rates are calculated based on 10- and 20-year Treasury note values **on December 1, 2023**, plus a risk premium of 325 basis points.
- Tax equity investors continue to be assumed to take the most valuable share of the project's net present value, and thus are assumed to constitute a larger share of the project's capital stack.
- Projects with bonus 40% or 50% ITC/CEIC values include larger tax equity shares of total equity than projects eligible for 30% credits.

Financing/Tax Inputs and Modeling Methods (4)

- Specific financing inputs are as follows
- Note that the optimal debt level is algorithmically determined such that a project is assigned the most debt possible under a given incentive level
  - Thus, the debt levels shown below are for illustrative purposes only

Component	25 kW_{AC} (Residential)	≤ 25 kW_{AC} (Small C&I)	>25-250 kW_{AC}	>250-500 kW_{AC}	>500 kW-1.0 MW_{AC}	>1-5 MW_{AC}	Non-Taxable
Debt (% of Costs)	51.0%	53.0%	47.0%	51.0%	51.5%	51.5%	75%
Debt Term (years)	10	10	19	19	19	19	20
Interest Rate on Term Debt (%)	7.045%	7.045%	7.177%	7.177%	7.177%	7.177%	3.000%
Lender's Fee (% of Total Borrowing)	1.00% (4.25%)	2.30%	1.00%	1.00%	1.00%	1.00%	1.00%
After-Tax Equity IRR (%)	12.60% (7.00%)	12.00%	12.42% (12.00%)	12.42%	11.52% (11.46%)	11.20% (11.00%)	3.000%
State Tax Rate	2.89%	2.89%	8.00%	8.00%	8.00%	8.00%	0.00%
Federal Tax Rate	6.32%	6.32%	21.00%	21.00%	21.00%	21.00%	0.00%

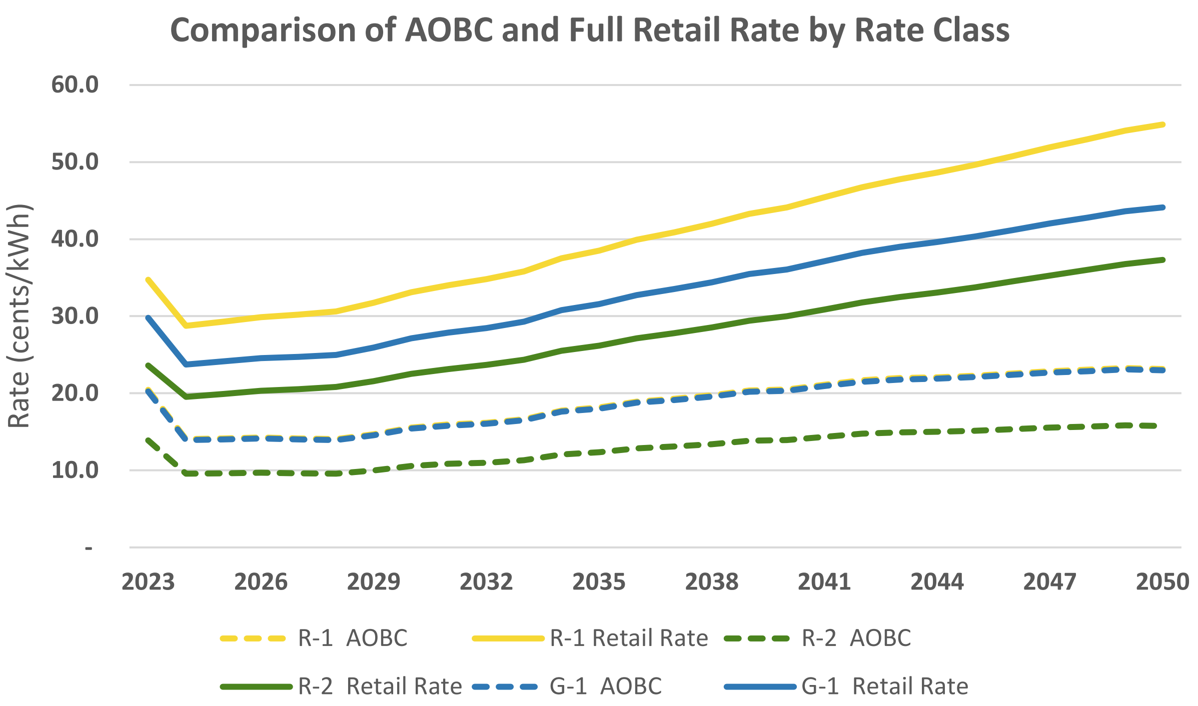
Red = Alternate inputs for Direct Owned (DO) projects
Green = Alternate input for project receiving 10% Bonus ITC
Purple = Alternate input for project receiving 20% Bonus ITC

Post-Tariff Net Metering Revenue

- Small projects (≤ 25 kW_{AC}) with only a 10-year SMART tariff term are expected to participate in net metering post-SMART tariff.
  - SEA assumed that 100% of energy is consumed behind the meter (BTM) for small projects, thus earning the full retail rate.
- To include post-tariff revenue in the CREST model's analysis, SEA forecasted retail rates for residential and low-income residential rate classes and applied the resulting forecast as post-tariff revenue.
  - A 50% discount was applied all post-tariff revenue to reflect uncertainties regarding policy and rate variability.
  - See next slide for a graph of the retail rate forecast by rate class.

Bill Credit Expenses

- For all projects assumed to offer a bill credit to offtakers (e.g., third-party owned projects), SEA modeled expenses related to bill credit discounts provided to offtakers.
  - SEA assumed non-low-income offtakers receive a 15% discount, whereas low-income offtakers receive a 20% discount.
  - SEA modeled additional High/Low bill credit discount cases (+/- 5%).
- The applicable % discount was applied to the project's assumed energy value, adjusting for the difference between the generator's and subscribers' rate classes.
  - See table (bottom right) for rate class assumptions.
- For small solar (≤ 25 kW_{AC}), the energy value was calculated as the forecasted full retail rate.
- For large solar, SEA assumed that projects participated in SMART as AOBC facilities and would receive bill credits equal to the generation (i.e., basic service) component of the retail rate.



Project Type	Generator Rate Class	Offtaker Rate Class (% split)		
		R-1	R-2	G-1
Resi Rooftop	R-1	**100%**	0%	0%
Resi Rooftop (LIS)	R-2	0%	**100%**	0%
LIPS	G-1	**50%**	**50%**	0%
CSS	G-1	**51%**	0%	**49%**
LICSS	G-1	0%	**51%**	**49%**
All Other	G-1	0%	0%	**100%**

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Task 1 Analysis Results: Levelized Base and Incremental Revenue Requirements of SMART-Eligible Project Types

Levelized Base Revenue Requirements

Solar PV Projects <u>Less Than or Equal To</u> 25 kW_{AC}

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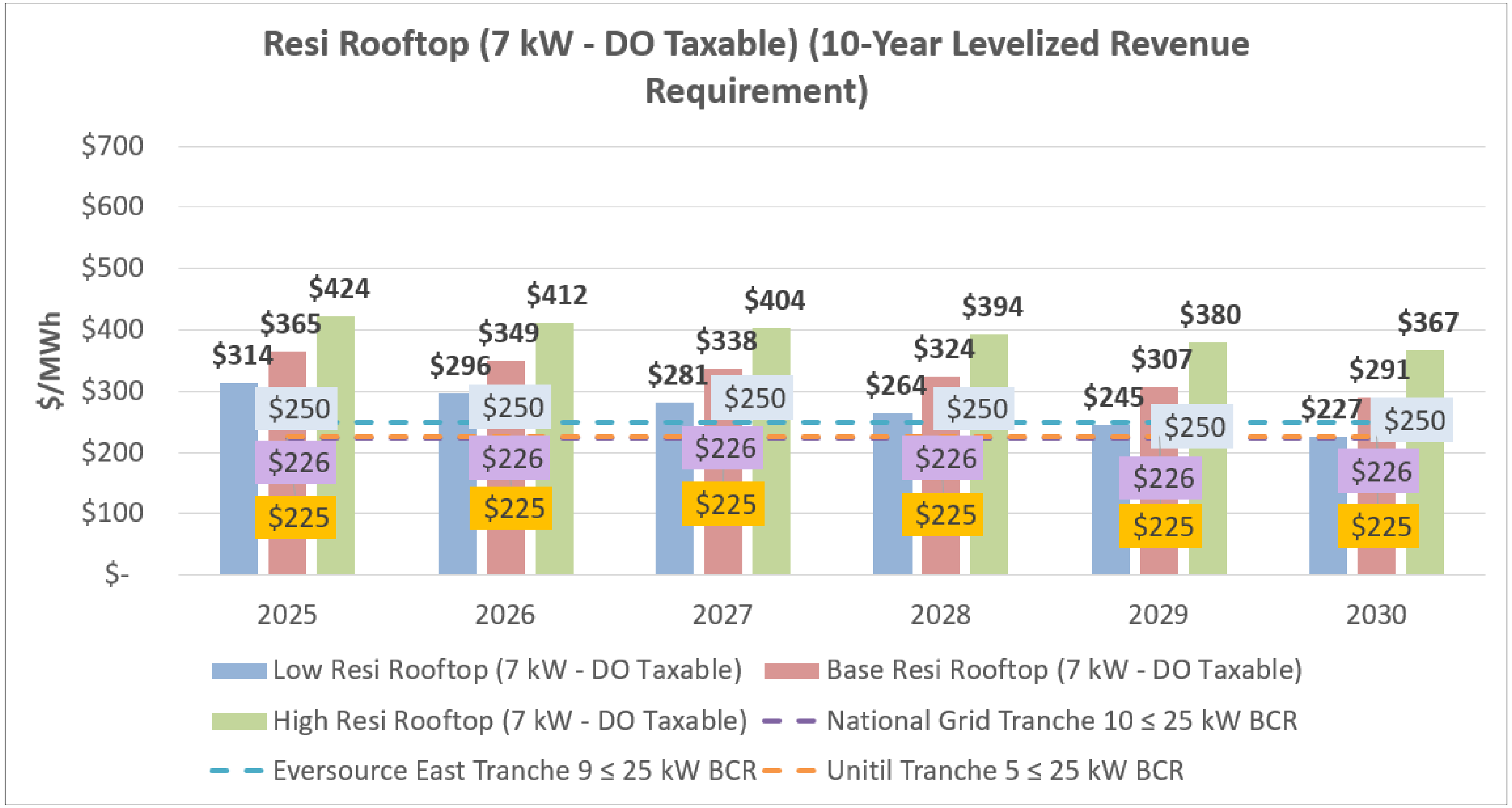
Overarching Observations: Levelized Base Revenue Requirements For Solar PV Projects <=25 kW_{AC}

- As in all the eligible project size bins, the Base Compensation Rates (BCRs) for projects <=25 kW_{AC} in the SMART program are (for the reasons described in the Introduction) structurally misaligned with the costs of eligible resources.
- While the cost of Direct Ownership (DO) projects is substantially misaligned with the BCRs, the degree of misalignment is especially pronounced for Third-Party Owned projects in this sector, given that DO projects are often financed at consumer financing rates that have internal rate of return (IRR) requirements well below those required by investors for a taxable corporate entity.
- The term of the potential tariff in question for projects <=25 kW_{AC} (whether 10 or 20 years) has only a mild to moderate impact on the levelized base revenue requirement over the term of such projects. However, it is one that converges towards being highly similar because of the (expected) more rapidly declining long-term costs and learning rates of solar PV and energy storage in this sector, as well as the increasing expected cost of providing bill credits equivalent to a fixed proportion of residential (R-1) and small commercial (G-1) rates.
- A more consequential impact on the levelized base revenue requirement in this sector is the inclusion of post-tariff revenue (which, in this case, is a mix of avoided retail rates). When such revenue is not included for 10-year projects, the total revenue requirements over 10 years are substantially higher than for those that consider net metering and retail rate compensation in years 11 and thereafter.
- Low-income solar TPO projects, though relatively rare to date in the state, reflect an even higher tier of cost requirement as a result of the added cost of customer acquisition for low-income customers. However, we note that the main provider in this space also offers energy efficiency upgrades as part of a package with such projects.

7 kW$_{AC}$ Resi Project (10-Year $/MWh, Direct Ownership, Taxable Entity (DO-Taxable))

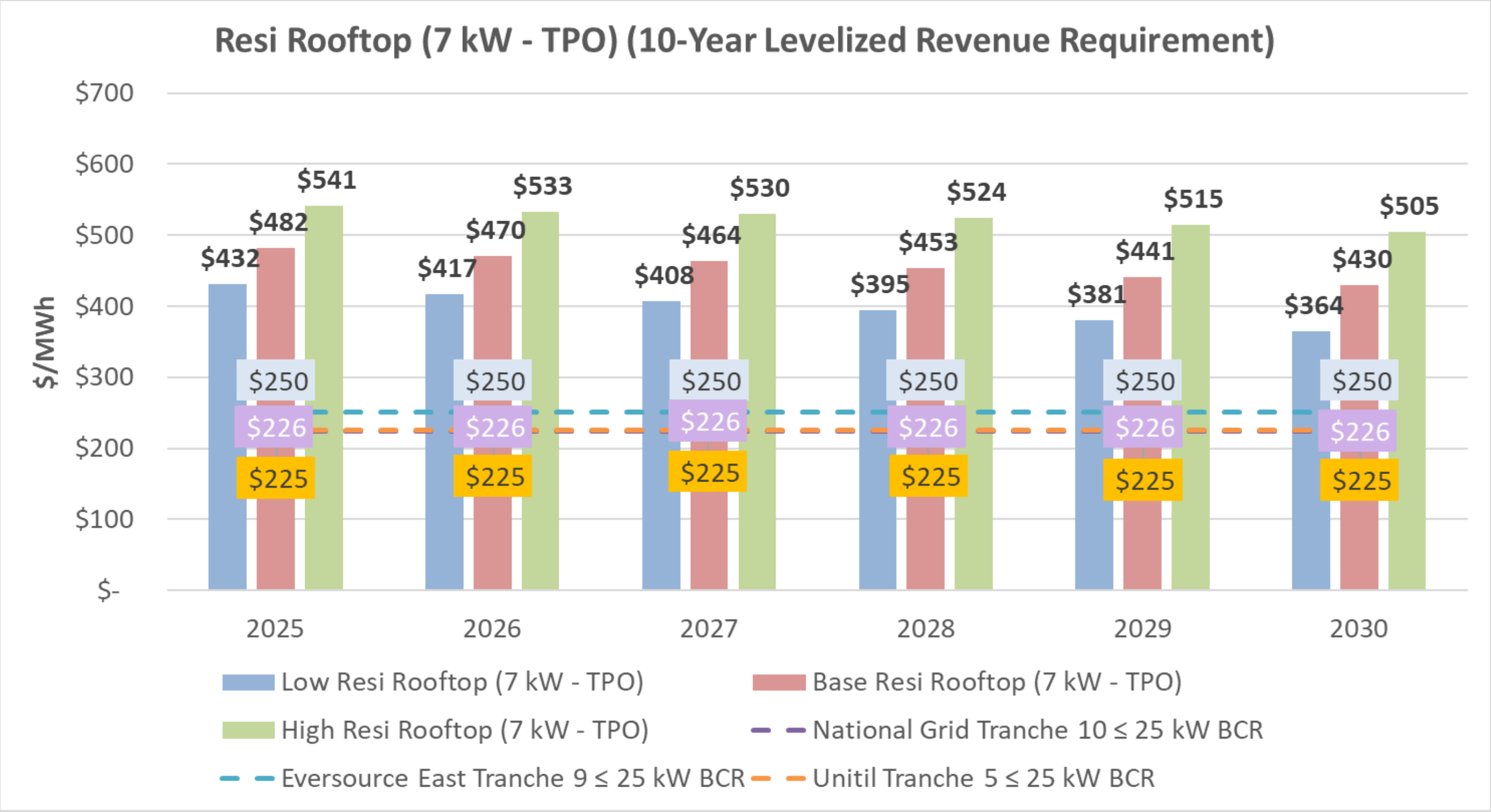
- A significant objective of the instant analysis commissioned by DOER is to quantify the impacts of the differential costs between third-party and DO projects.
- The main sector in which typical projects show the most diverse mix of both financing models are the residential mass market, as well as small C&I projects, with nameplate capacities less than 25 kW$_{AC}$.
- Overall, SEA's modeling suggests that the levelized base revenue requirements of DO projects is often substantially less than those third-party ownership. However, these projects still have levelized 10-year costs that have risen substantially in recent years (with a 2025 nominal range between $314-$424/MWh).
- Current BCRs available in each EDC service territory remain dramatically below cost, at about 50%-60% of total 10-year Base Cost levelized requirements, even without the inclusion of energy storage.



NOTE: Since nearly all projects <=25 kW$_{AC}$ are roof-mounted, the base modeled project in this sector is also assumed, for the purpose of cost analysis, to be roof-mounted.

7 kW_{AC} Residential (Resi) Project ($/MWh, 10-Year Tariff, Third Party Owned (TPO))

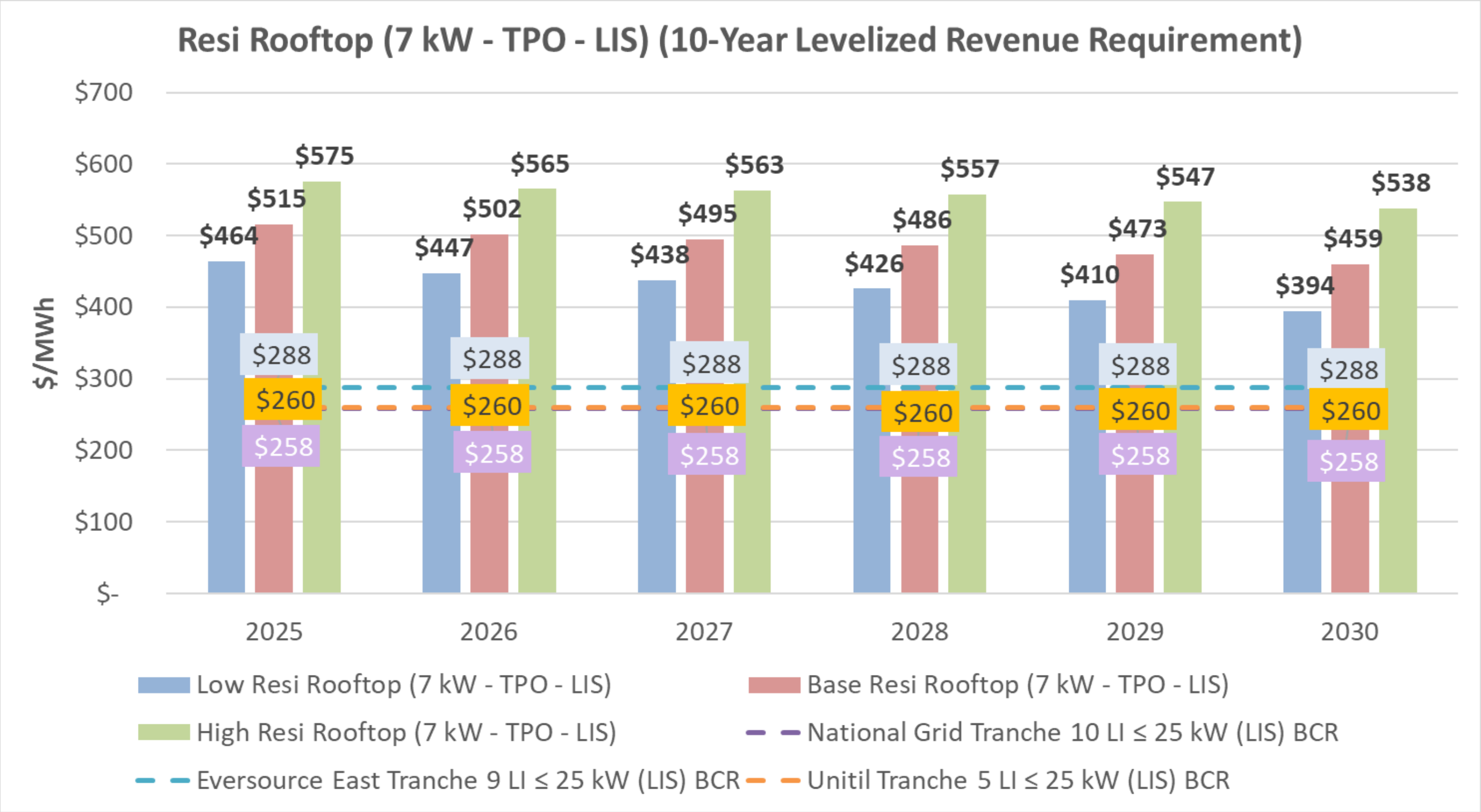
- Relative to DO projects, SEA's modeling suggests that despite their ability to provide customers unable to finance their solar PV systems with cash, TPO projects must meet substantially higher investor return expectations than those of typical homeowners.
- SEA's modeling finds that in the case of residential TPO projects, applicable 10-year levelized base 2025 nominal revenue requirements range between $432-$541/MWh (43.2-54.1 ¢/kWh).
- These revenue requirements stand in the starkest contrast of all eligible resources in the SMART program, with current BCRs falling more than 50% short of these levelized values.
- Via other analyses, SEA has observed the impact of this wide divergence between available SMART values and current costs, which has been an exponential increase in solar PV projects pursuing net metering compensation outside the SMART program across all EDC territories.



NOTE: Since nearly all projects <=25 kW_{AC} are roof-mounted, the base modeled project in this sector is also assumed, for the purpose of cost analysis, to be roof-mounted.

7 kW$_{AC}$ Residential (Resi) Project ($/MWh, 10-Year Tariff, Low Income Solar – Third Party Owned (TPO))

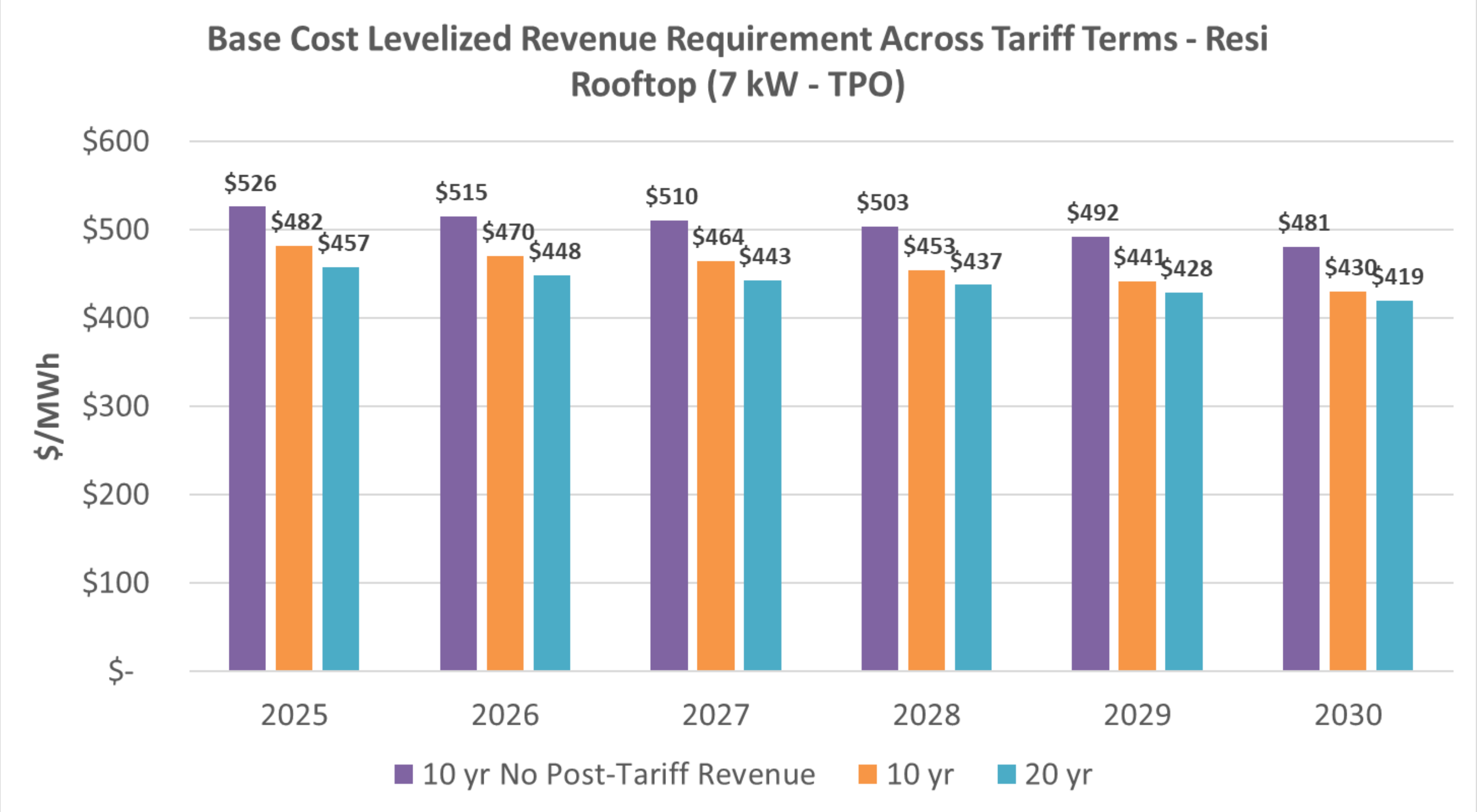
- SEA's modeling finds that in the case of residential TPO projects serving low-income customers, applicable 10-year levelized base 2025 nominal revenue requirements range between $464-$575/MWh (46.4-57.5 ¢/kWh).
- Current BCRs fall slightly less than 50% short of these levelized values, in part because these values are higher than those for market-rate residential projects.
- Low-income solar TPO projects, though relatively rare to date in the state, reflect an even higher tier of cost requirement as a result of the added cost of customer acquisition for low-income customers.
- However, we note that the main provider in this space also offers energy efficiency upgrades as part of a package with such projects.



NOTE: Since nearly all projects <=25 kW$_{AC}$ are roof-mounted, the base modeled project in this sector is also assumed, for the purpose of cost analysis, to be roof-mounted.

7 kW_{AC} Resi $/MWh Comparison Across Tariff Terms

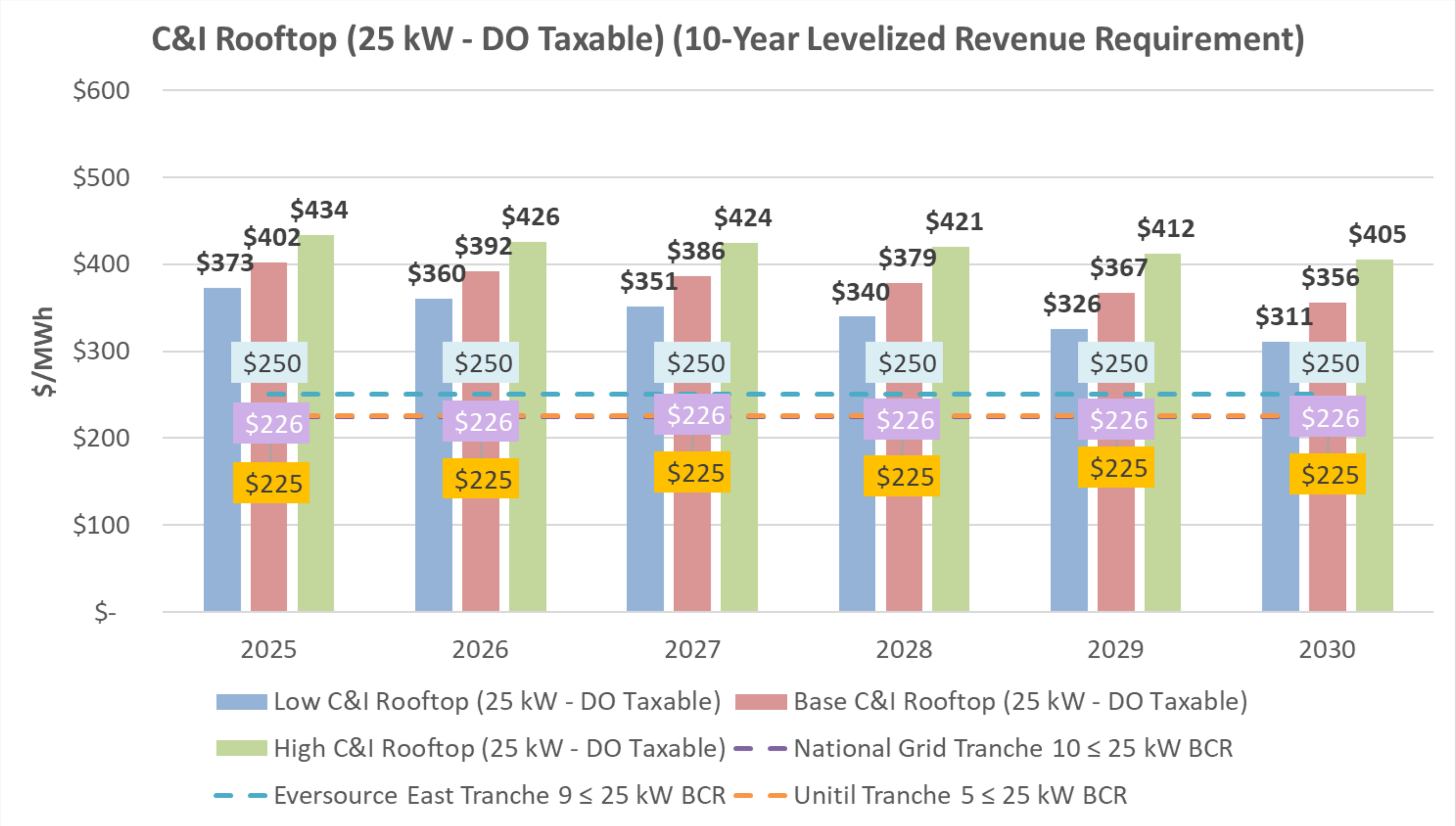
- At present, SMART eligible projects <=25 kW_{AC} receive 10-year tariff compensation, as opposed to the 20-year tariff compensation for projects greater than 25 kW_{AC}.
- All other factors held equal, this approach was taken when the SMART program was originally established, because the shorter tariff term ultimately resulted in a longer period in which benefits of said projects could accrue following the end of the tariff term.
- Over the 2025-2030 analysis period, SEA's modeling finds that for TPO projects, the increase in net metering and retail rates over time (and the cost of providing discounts to bill credits to customers), the difference between 10- and 20-year levelized base revenue requirements shrinks nearly to zero.
- For DO projects, this convergence is not as significant as for TPO projects, since DO project owners, as the participant, do not have to provide bill credits to offtakers.
- However, if the availability of post-tariff revenue is not assumed, the revenue requirements increases significantly.



NOTE: Since nearly all projects <=25 kW_{AC} are roof-mounted, the base modeled project in this sector is also assumed, for the purpose of cost analysis, to be roof-mounted.

25 kW_{AC} Small Commercial/Industrial Project (C&I) ($/MWh, 10-Year Tariff, DO-Taxable)

- As for residential DO projects, small commercial DO projects face a similar misalignment in compensation in the SMART program relative to their 10-year levelized revenue requirements.
- Specifically, SEA's modeling suggests that 10-year levelized base revenue requirements for this category are between $373-$434/MWh (37.3-43.4 ¢/kWh) in nominal dollars in 2025.
- As compared to current BCRs by EDC, the Base Cost estimate differs from current Eversource rates by over $150/MWh (15.0 ¢/kWh, the smallest difference by EDC of all three) and over $175/MWh (17.5 ¢/kWh) for Until.
- Relative to residential host-owned projects, this is a notable increase in costs, because such projects require commercial financing (with an assumed corporate hurdle rate of 12% as the target after-tax equity internal rate of return (IRR).
- Over time, however, there is a larger uncertainty band with regard to the costs of these projects, in significant part because <=25 kW_{AC} projects, in all cases, are assumed to be more susceptible to cost reductions.



NOTE: Since nearly all projects <=25 kW_{AC} are roof-mounted, the base modeled project in this sector is also assumed, for the purpose of cost analysis, to be roof-mounted.

Levelized Base Revenue Requirements

Solar PV Projects Greater Than 25 kW_{AC}

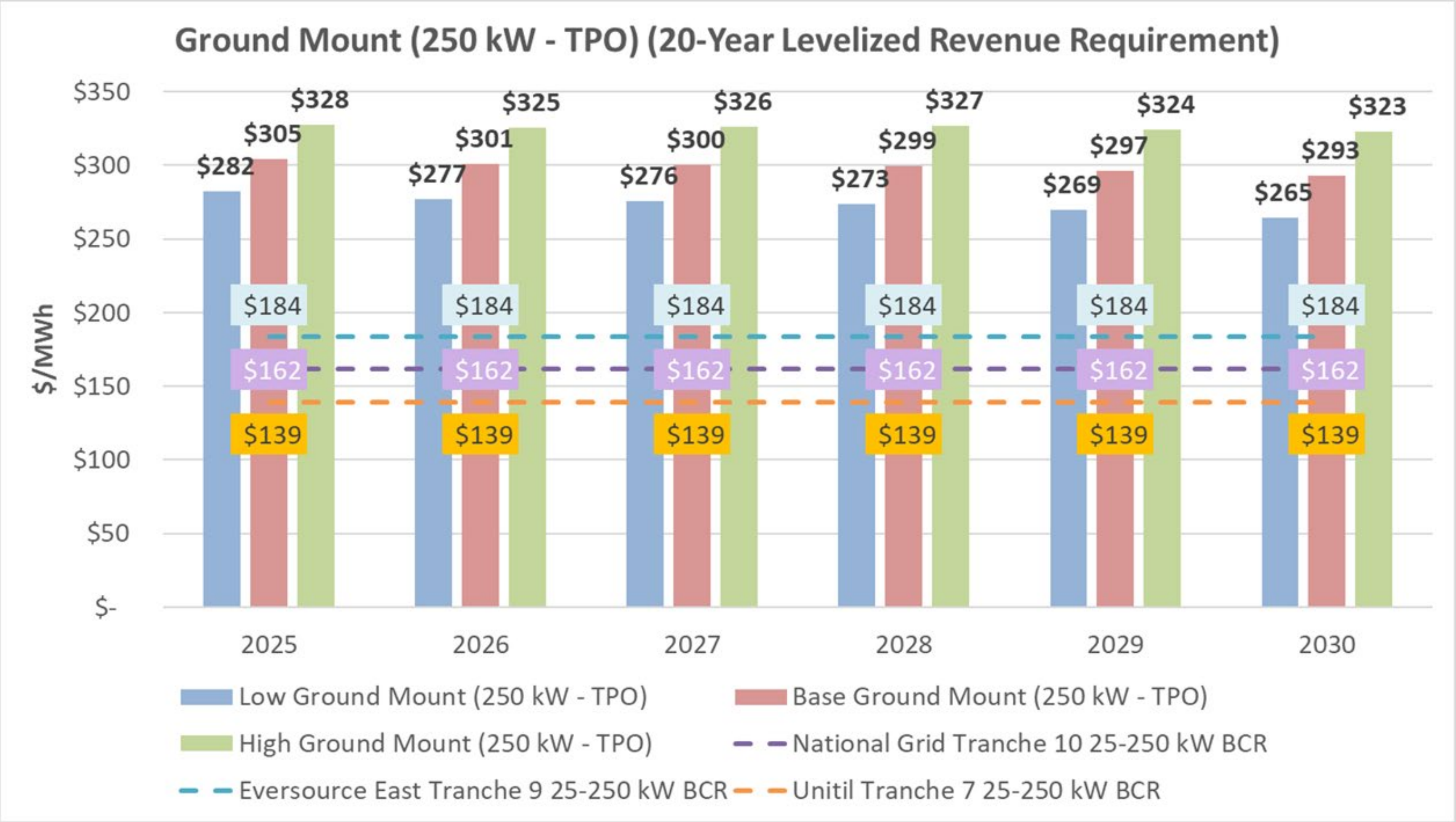
Sustainable Energy Advantage, LLC

Overarching Observations: Levelized Base Revenue Requirements for Solar PV Projects >25 kW_{AC}

- Though projects greater than 25 kW_{AC} tend to have more (and higher) non-O&M unit operating costs at larger project scales, the economies of scale created by declining installed capital costs at increasing project scale more than overcomes these unit operating cost increases and results in substantially lower levelized revenue requirements at larger project scales.
- Despite facing somewhat smaller structural compensation misalignments relative to the <=25 kW_{AC} subsectors, projects greater than 25 kW_{AC} will not be able to generally rely upon BCRs that investors would consider to be sufficient, bankable revenue streams without further action to change compensation rates in the program.
- Though projects >1 MW_{AC} have the lowest levelized base revenue requirements in the program, these projects are unlikely to experience as deep cost reductions between now and 2030 as a result of the high cost of interconnecting such projects to the transmission and distribution systems.
- Projects eligible for elective payments of cash in lieu of a tax credit are assumed to have lower levelized revenue requirements than those not eligible for such provisions, in significant part because these projects are financed with less expensive private capital (e.g., municipal bond financings) than typical project finance capital.
- However, participants in the elective payment/"direct pay" market tend to be non-profits or local governments that do not traditionally have substantial risk appetite, and often rely on third-party project owners to take the financial risk of ownership, while benefiting from savings associated with offtake. Therefore, if DOER wishes to encourage development in this emerging sector, it will likely have to encourage such projects with both economic and non-economic means.

>25-250 kW_{AC} C&I (Low/Base/High Cost, 20-Year $/MWh, TPO)

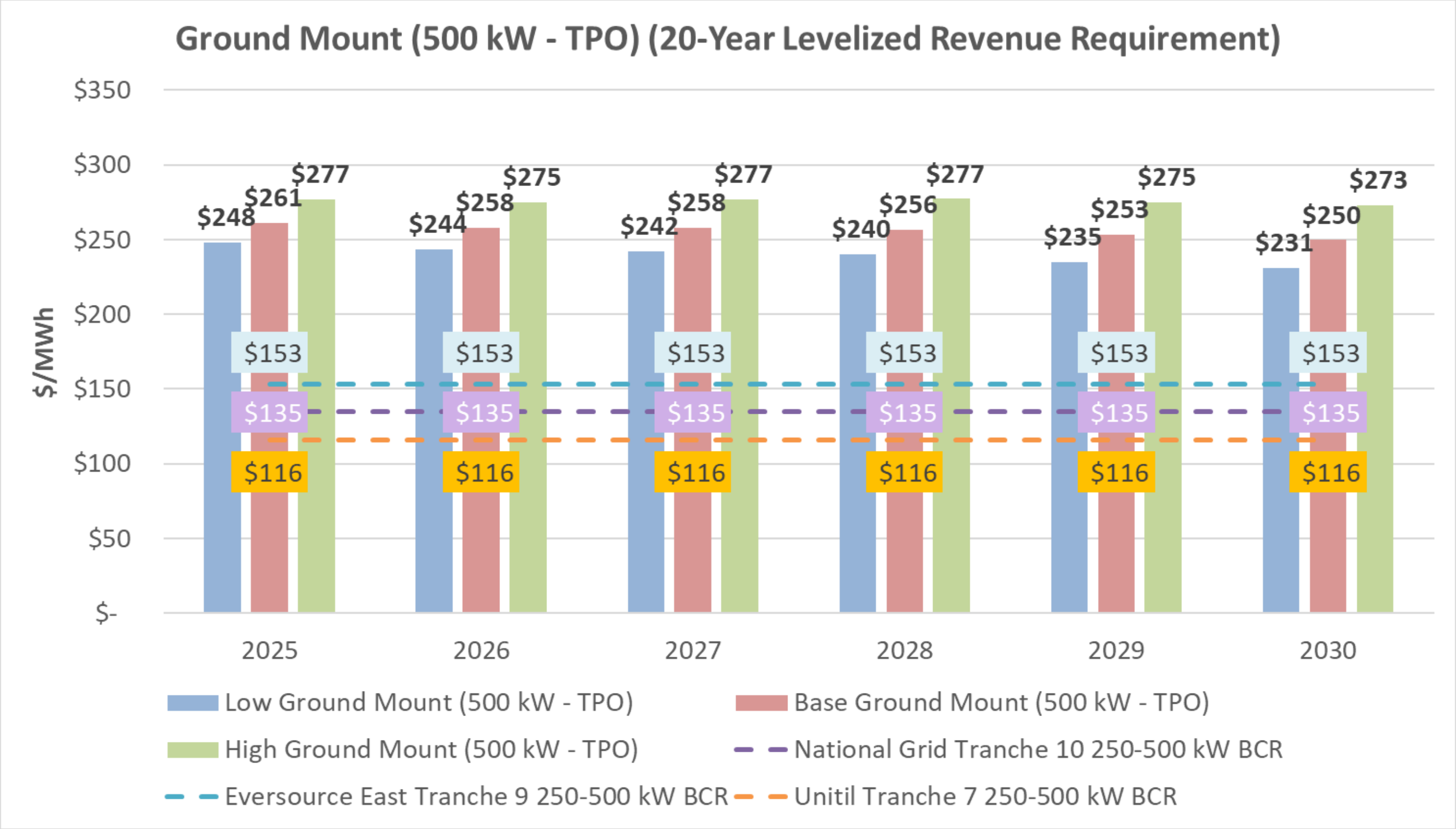
- Under Low/Base/High Cost starting value/trajectory assumptions, SEA's modeling indicates a likely range of levelized base revenue requirements over a 20 year tariff life of $283-$328/MWh (28.3-32.8 ¢/kWh) in 2025 in nominal dollars.
- These relative differences grow over the analysis period from 2025 to 2030. For example, in 2030, the same Low, Base and High Cost assumptions yield a likely range of $265-$323/MWh (26.5-32.3 ¢/kWh), a gap that increases as a result of the introduction of assumed decline rates in the Base and Low cases.
- As with the results in the <=25 kW_{AC} categories, the >25-250 results illustrate structural misalignment of current SMART BCR thresholds with the cost of eligible resources. Relative to the currently-available EDC block value, SEA's Base Cost estimates in 2025 range from $121/MWh above current Eversource BCR values for >25-250 kW_{AC} projects, to $166/MWh above current Unitil BCRs.
- Relative to the <=25 kW category, >25-250 kW projects often have higher financing costs (depending on ownership type) and may also require annual lease payments to property owners, as well as project management costs. However, such projects benefit from increasing scale economies that optimize at the 250 kW threshold.



NOTE: Though some solar PV projects in the above size bin are roof-mounted and others are ground-mounted, the base modeled project in this bin is assumed to be ground-mounted in order to serve as a basis for determining the incremental cost of projects in certain subsectors.

>250-500 kW_{AC} C&I (Low/Base/High Cost, 20-Year $/MWh, TPO)

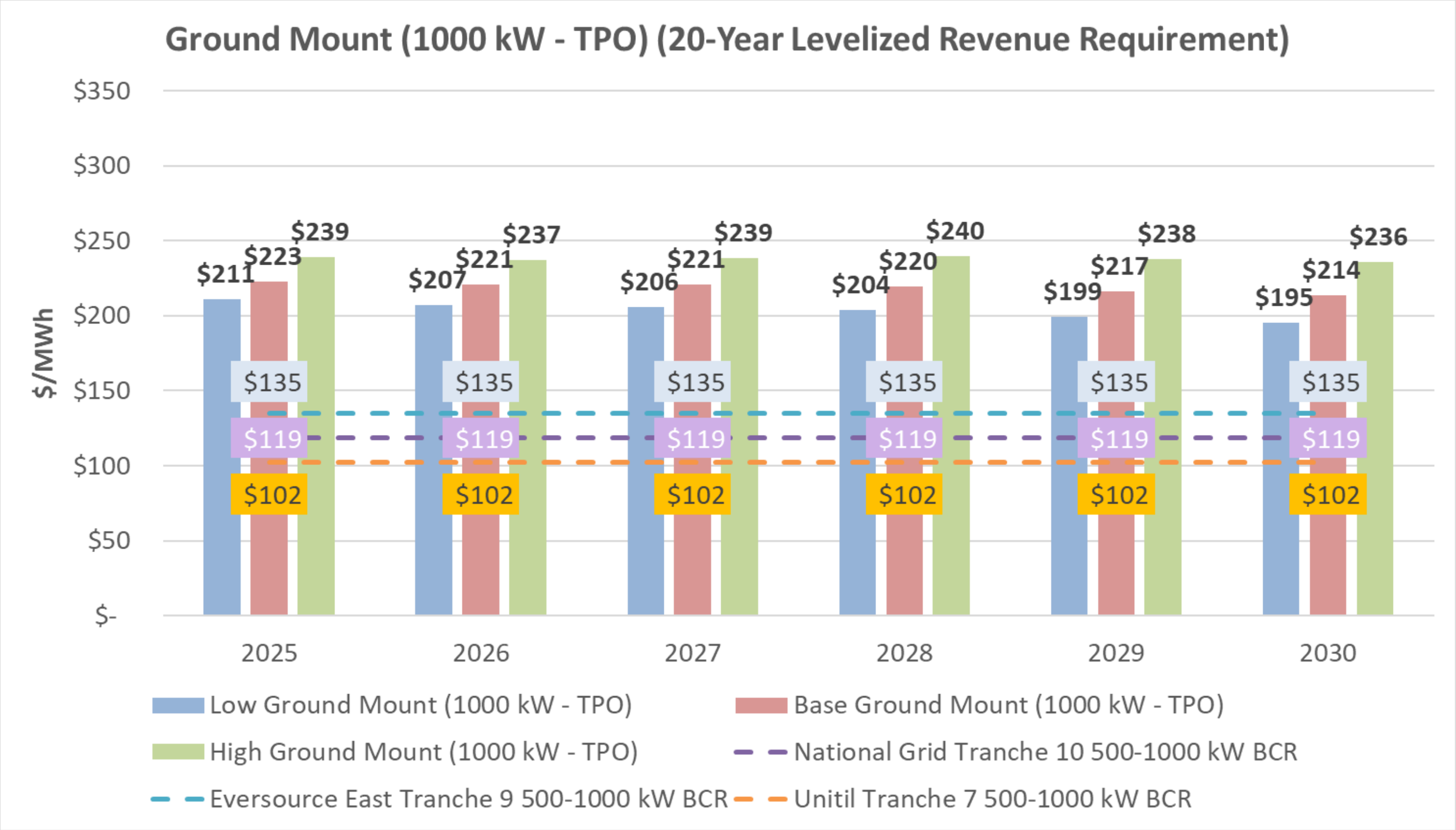
- Under the same Low/Base/High assumptions, SEA's modeling indicates a likely range of levelized base revenue requirements over a 20 year tariff life of $248-$277/MWh in nominal dollars (24.8-27.7 ¢/kWh) in 2025.
- Like >25-250, this relative spread grows over the analysis period from 2025 to 2030 as a result of the introduction of assumed decline rates. For example, in 2030, the same Low, Base and High Cost assumptions yield a likely range of $231-$273/MWh (26.5-32.3 ¢/kWh), also in nominal dollars.
- As with the results in the >25-250 kW_{AC} category the >250-500 kW_{AC} results also illustrate structural misalignment of SMART BCRs with the cost of eligible resources. Relative to the currently-available EDC block value, SEA's Base Cost estimates in 2025 range from $126/MWh above current Eversource BCR values to $142/MWh above current Unitil BCR values in the same category.
- Relative to the >25-250 kW_{AC} category, >250-500 kW projects often have higher interconnection, annual lease rate (depending on ownership type), project management and insurance costs. However, the overall impact of such cost increases are overcome, compared to >25-250 projects, by increasing production estimates and economies of scale that optimize at the top end of the size bin (500 kW_{AC}).



NOTE: Though some solar PV projects in the above size bin are roof-mounted and others are ground-mounted, the base modeled project in this bin is assumed to be ground-mounted in order to serve as a basis for determining the incremental cost of projects in certain subsectors.

>500 kW_{AC} -1 MW_{AC} C&I (20-Year $/MWh, TPO)

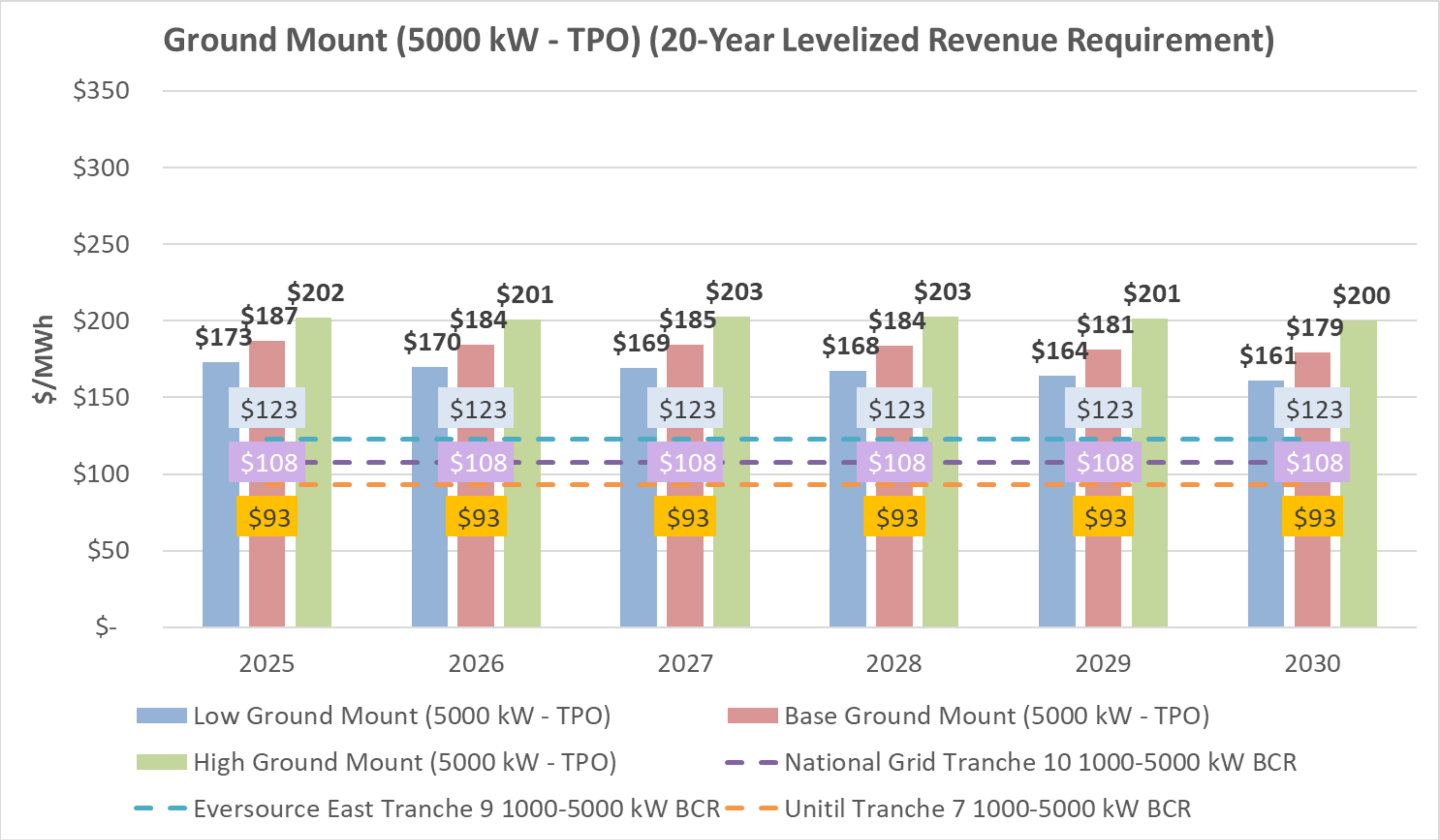
- In general, the differences in initial levelized revenue requirements across Low/Base/High cost cases tend to narrow as projects increase in size, as a result of the larger amount of capacity and system production over which costs are spread. SEA's modeling indicates a likely range of levelized base revenue requirements over a 20 year tariff life of $211-$239/MWh in nominal dollars (21.1-23.9 ¢/kWh) in 2025.
- Over the 2025-2030 analysis period, the same Low, Base and High Cost assumptions yield a likely range of $195-$236/MWh (19.5-23.6 ¢/kWh), also in nominal dollars.
- Though the absolute differences between SEA's estimates of the cost of eligible systems decline with increasing size, the relative degree to which such costs are misaligned with the current BCRs does not substantially decrease. Though Eversource's BCRs are now less than $100 less than the Base Cost estimate in 2025, such BCRs remain around 53% of total costs (relative to 51% for 250-500 kW_{AC} projects)
- Though nearly all unit cost values in the 500 kW-1 MW category increase across operating expense categories rise, proportionally larger increases in assumed production and decreases in unit installed costs result in an approximate $40/MWh (~15%) cost reduction for Base Cost 2025 projects relative to 250-500 kW projects.



NOTE: Though some solar PV projects in the above size bin are roof-mounted and others are ground-mounted, the base modeled project in this bin is assumed to be ground-mounted in order to serve as a basis for determining the incremental cost of projects in certain subsectors.

>1 MW_{AC} (20-Year $/MWh, TPO)

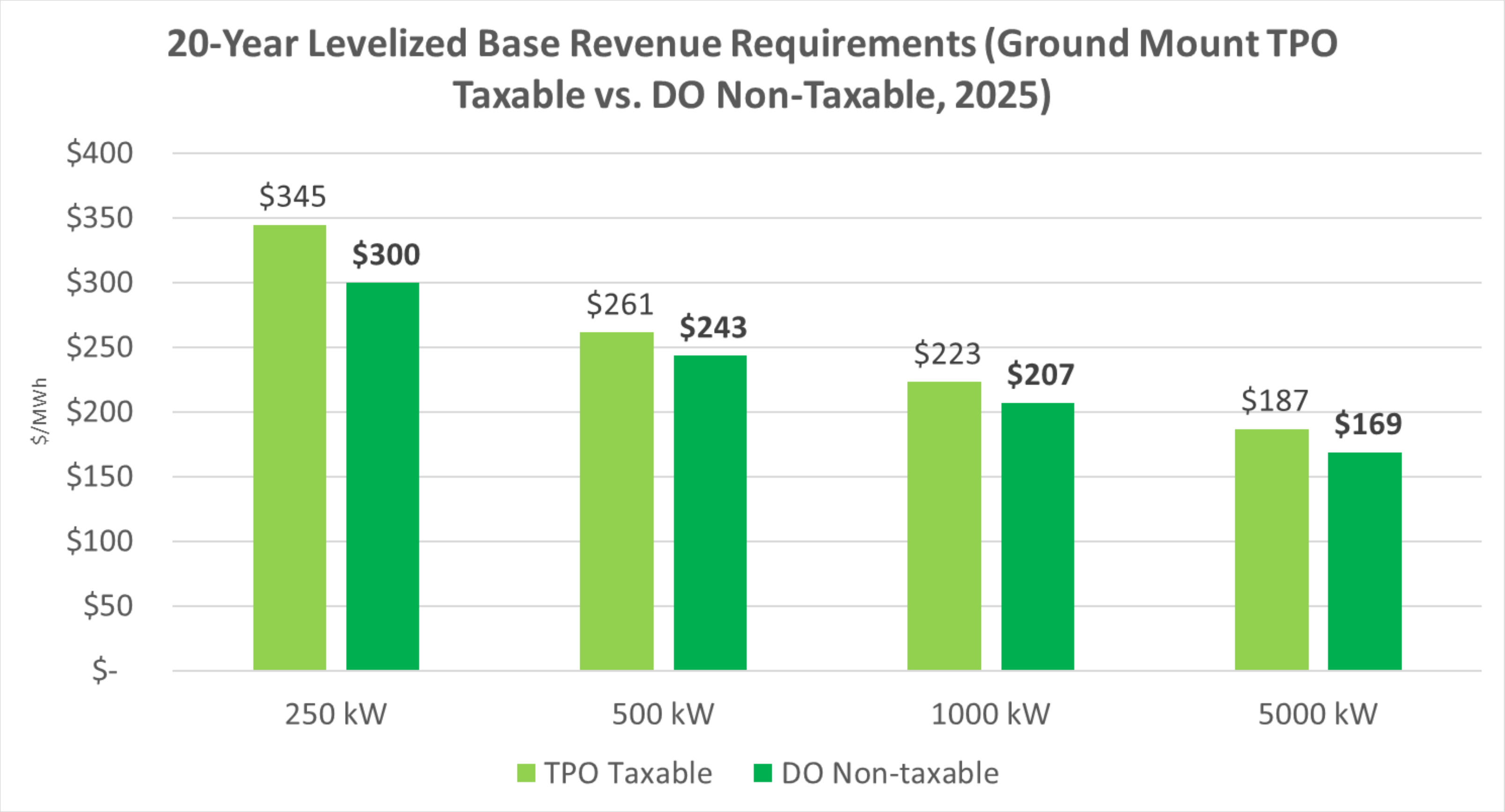
- The values for projects the top end of the eligibility range reflect a similarly proportional Low/Base/High split in 2025. SEA's modeling indicates a likely range of levelized base revenue requirements over a 20-year tariff life of $173-$202/MWh in nominal dollars (17.0-20.2 ¢/kWh) in 2025. Though the levelized 20-year values are lower than for other categories, a similarly proportional spread emerges over the 2025-2030 analysis period.
- Though the overall gap between current EDC BCRs and our Base Cost result for >1 MW projects declines by 1%, the cost estimates continue to indicate structural misalignment with current compensation rates. At Base or Low Case decline rates, they are unlikely to re-align for the foreseeable future without specific action to re-align them.
- The most significant cost differences between >1 MW_{AC} and other categories regard the cost of interconnection. Though economies of scale and increases in assumed production result in a net decline in levelized revenue requirements, most projects greater than 1 MW_{AC} require substantially greater interconnection scrutiny, which results in substantial delays and high costs related to system modifications needed to connect them to the T&D system. As a result, these projects do not experience as substantial declines relative to smaller projects as they once did in the latter half of the 2010s.



NOTE: Though some solar PV projects in the above size bin are roof-mounted and others are ground-mounted, the base modeled project in this bin is assumed to be ground-mounted in order to serve as a basis for determining the incremental cost of projects in certain subsectors..

20-Year Levelized Base Revenue Requirement Comparison for Non-Taxable Entity (Direct Pay-Eligible) Projects

- As a result of P.L. 117-169 – Inflation Reduction Act of 2022, projects owned by non-taxable entities (including public entities and non-profit organizations) are permitted to receive an elective payment in lieu of a tax credit.
- SEA assumes that these projects are most likely to be developed at scale by public entities that have access to municipal bond financing markets.
- SEA's modeling shows that, as a result, these projects, at multiple project scales, have lower levelized base revenue requirements than projects requiring the raising of private capital. Specifically, we find that ground mounted projects accessing this financing projects tend to have about $20/MWh (2.0 ¢/kWh) lower such requirements, regardless of system scale.
- SEA cautions, however, that the relative assumed lower cost of these projects – which is driven by access to low-cost municipal bond financing – are thus far not commonplace in the Commonwealth. In our experience, this is because public entities looking to benefit from solar PV projects have opted to limit their risk via participation in a project via an offtake agreement, rather than assuming the risks of ownership.



NOTE #1: Since nearly all projects <=25 kW_{AC} are roof-mounted, the base modeled project in this sector is also assumed, for the purpose of cost analysis, to be roof-mounted.
NOTE #2: The difference between the results for the two ownership structures for the 250 kW_{AC} case is driven substantially by the fact that the only non-taxable entity use case in that category was a roof-mounted project. Our assessment is that the difference in most cases is limited.

Levelized Incremental Revenue Requirements for Projects Participating in Location-Based SMART Market Subsectors

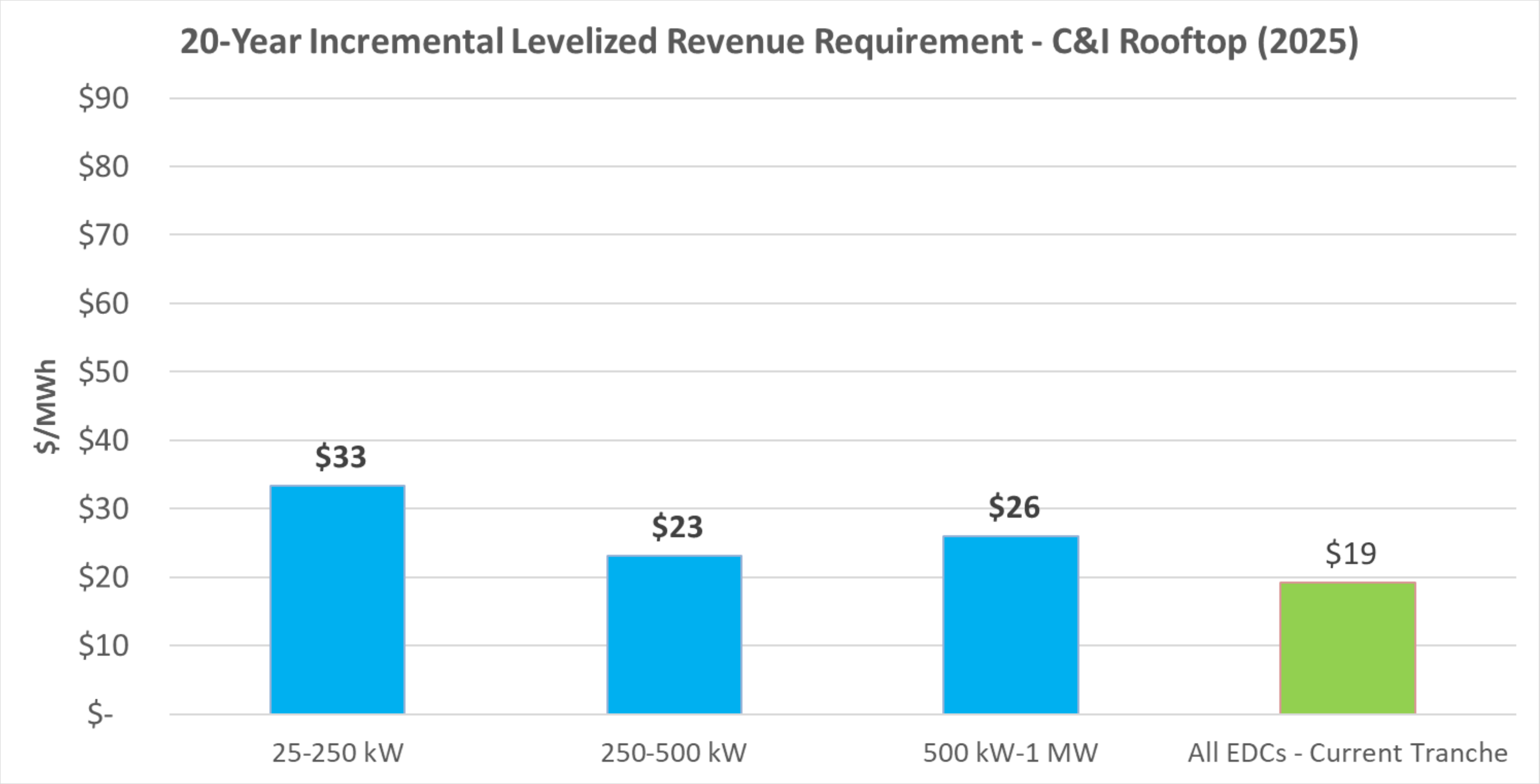
Solar PV Projects Greater than 25 kW_{AC} and Less than or Equal to 5 MW_{AC}

Sustainable Energy Advantage, LLC

Overarching Observations: Levelized Incremental Costs For Solar PV Projects in Location-Based Market Subsectors

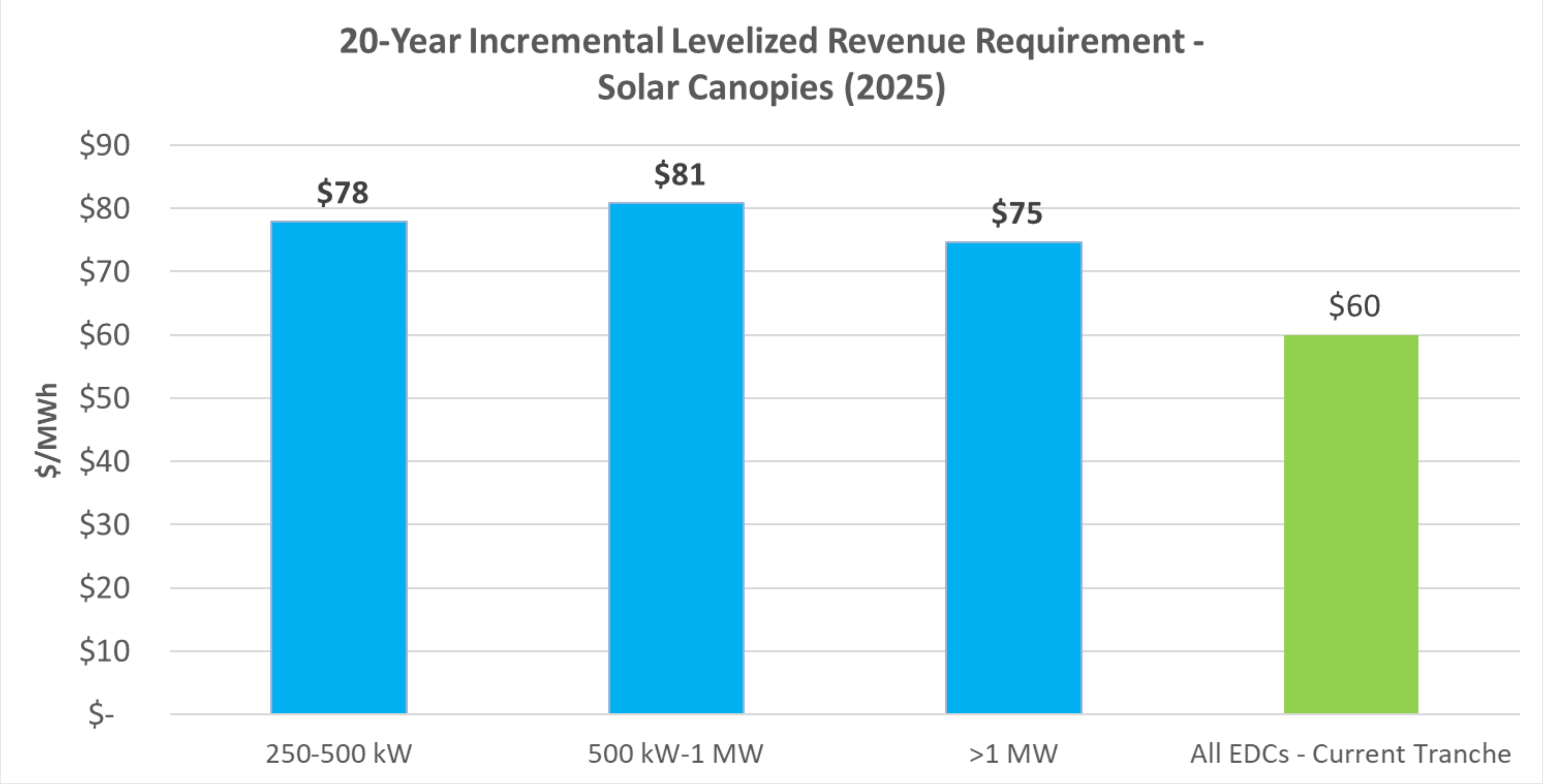
- Though the attractiveness of current compensation in the SMART program is undermined by the ongoing structural misalignment of the costs of greenfield ground-mounted systems with current BCRs, SEA's analysis suggests compensation in some market sectors in which projects can qualify for location-based adders remain relatively well (though not perfectly) aligned with incremental revenue requirements.
- These include Brownfield projects generally, as well as Landfill projects >1 MW_{AC}. The alignment of current adder values to incremental costs for projects in the Brownfield sector are improved incrementally by the availability (for some Brownfield projects) of bonus "energy community" federal Investment Tax Credits of 10% of the project's cost.
- However, SEA's analysis finds that, in all other cases, compensation for the other location-based market sectors is misaligned with the incremental revenue requirements of such projects. Indeed, comparisons of current compensation in these market sectors to the incremental revenue requirements of these projects these market sectors typically show misalignments of at least $20/MWh (2 ¢/kWh) too low, rising to 4 ¢/kWh or more for smaller Landfill projects.
- Therefore, if a potential component of changes to the SMART program involves the targeting of development to projects on disturbed parcels of land, further efforts are required to ensure these costs are consistent with the revenue requirements of such projects.

Rooftop Solar (Base Cost, 20-Year $/MWh, TPO)



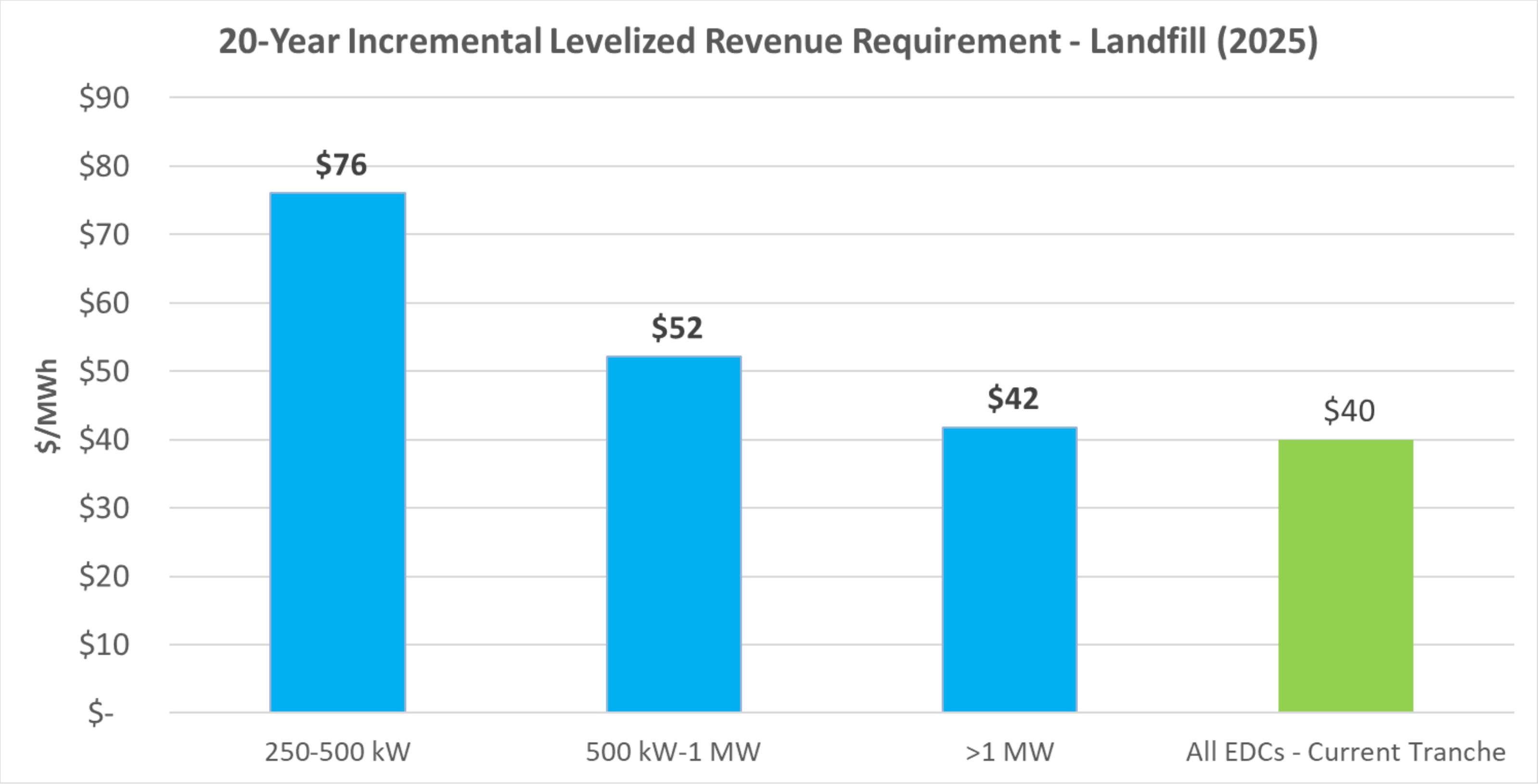
- SEA's modeling indicates that, for solar PV projects greater than 25 kW sited on rooftops, current costs range from $23-$33/MWh (2.3-3.3 ¢/kWh), depending on the size of the project.
- This value is slightly above the current statewide tranche value of $19/MWh (1.9 ¢/kWh).
- The main drivers of difference between roof-mounted projects and Base Cost ground mount projects include:
  - Higher installed capital costs due to their siting on roofs, which are driven by differences in module types and sizes, as well as other balance of system (BOS) materials;
  - Lower production due to non-ideal tilts/azimuths associated with siting on existing buildings, rather than more optimally-angled pieces of unoccupied land; and
  - Higher O&M and slightly higher insurance costs due to its roof mounting.
- The value for >250-500 kW projects is somewhat lower than anticipated by typical declines resulting from increased economies of scale, but SEA notes that this is purely a reflection of industry-reported data from the survey conducted by the team.

Solar Canopies (Base Cost, 20-Year $/MWh, TPO)



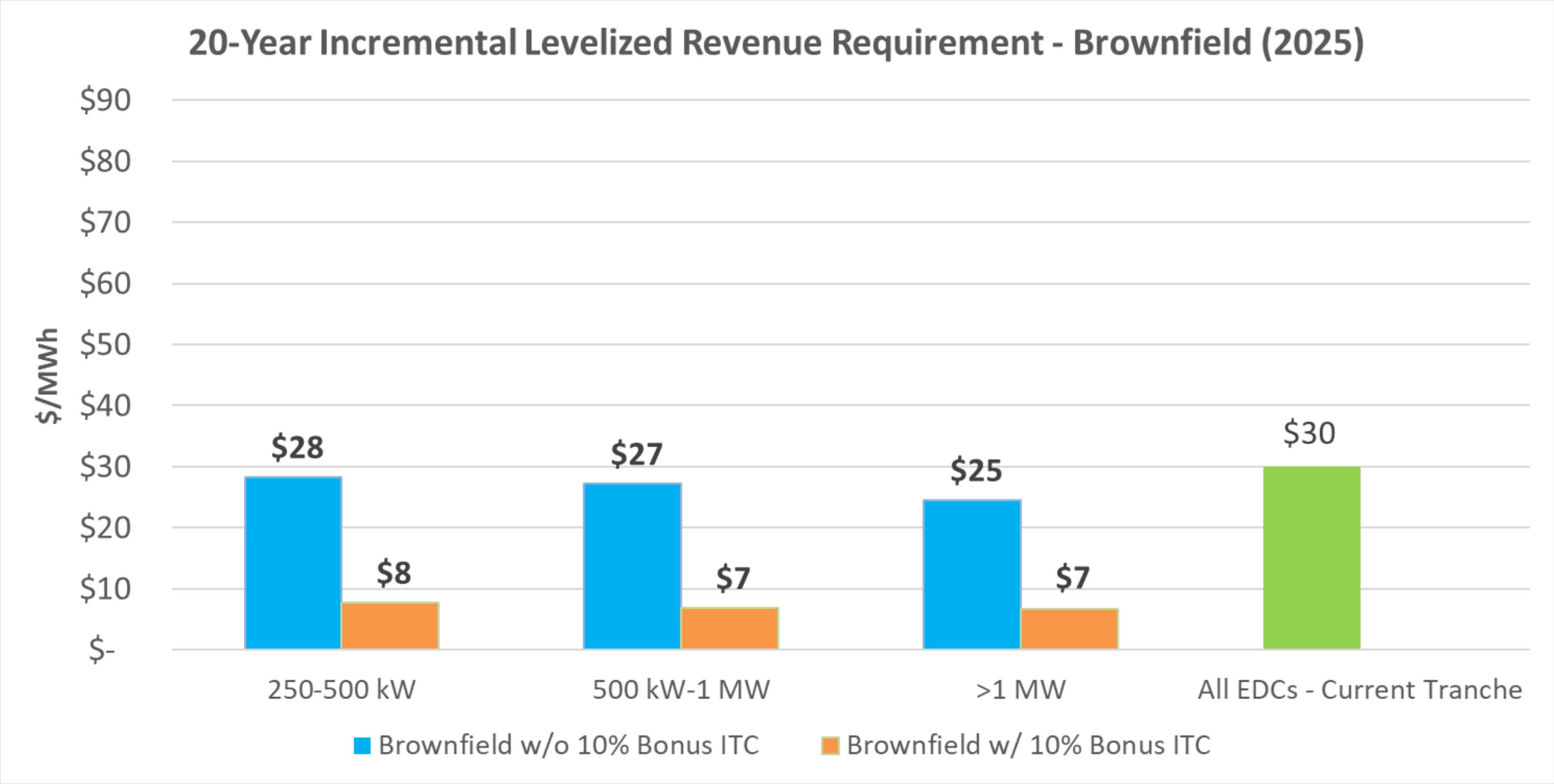
- SEA's modeling indicates that, for solar PV projects mounted on solar canopies, current costs range from $75-$81/MWh (7.5-8.1 ¢/kWh), depending on the size of the project.
- This value is materially above the current statewide tranche value of $60/MWh (6.0 ¢/kWh) and has been driven significantly by strong increases in the price of steel required for canopy racking and mounting in recent years.
- The main drivers of difference between roof-mounted projects and Base Cost ground mount projects include:
  - Substantially higher installed capital costs due to higher racking and mounting costs (which are sensitive to the price of steel)
  - Substantially higher O&M costs (due to the relative inaccessibility of canopies when compared to ground-mounted projects).
  - Much lower production than even rooftops, due to non-ideal tilts/azimuths associated with siting above parking lots, due to requirement to provide parking shade, manage more substantial snow and wind loads as well as drainage, and utilize parcels that are not optimally angled with the sun.
- The value for >250-500 kW projects is somewhat lower than anticipated by typical declines resulting from increased economies of scale, but SEA notes that this is purely a reflection of industry-reported data from the survey conducted by our team.

Landfill Solar (Base Cost, 20-Year $/MWh, TPO)



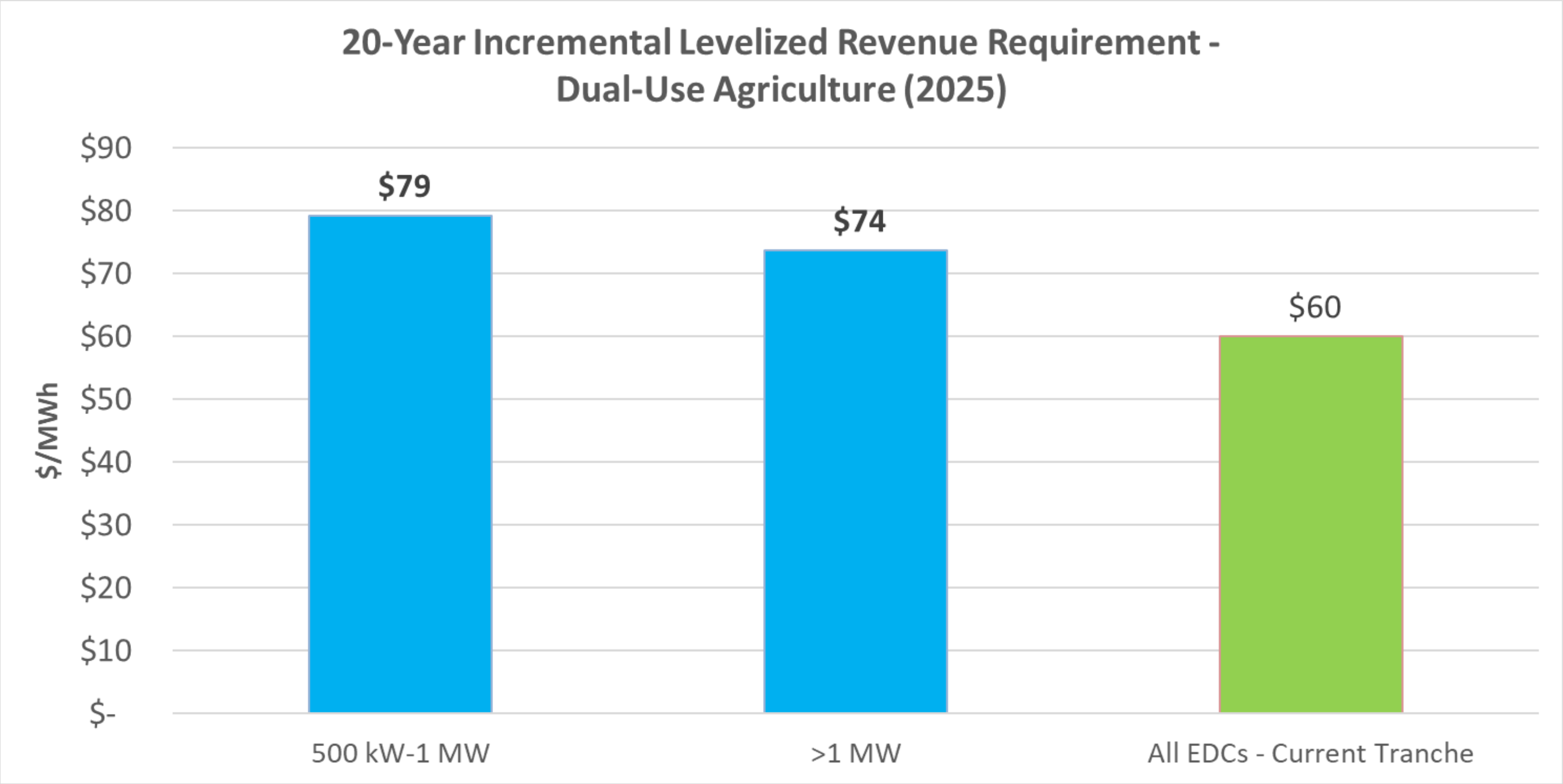
- SEA's modeling indicates that, for solar PV projects mounted on already-capped landfills, current costs carry a relatively wide range of $42-$76/MWh (4.2-7.6 ¢/kWh), depending on the size of the project.
- For projects >1 MW, these modeled values are relatively in line with the current statewide tranche value of $40/MWh (4.0 ¢/kWh) but is insufficient to meet the costs of siting projects on smaller landfill parcels, which the state may choose to target for development as a class of "preferred sites".
- The main drivers of difference between landfill projects and Base Cost ground mount projects include:
  - Higher installed capital costs associated with fixed costs of preparing the site, the permitting process, and with mitigation measures required to ensure the cap/membrane of the landfill is not permeated;
  - Higher O&M costs (due to siting on a landfill);
  - Lower production due to the sloping nature and non-optimal azimuth of a capped landfill, relative to greenfield ground-mounted parcels optimally angled with the sun.
- The difference in incremental levelized revenue requirement at smaller sizes is largely due to (it is our understanding) the relatively fixed nature of the costs (such as for permitting) that do not vary as significantly by project size.

Brownfield Solar (Base Cost, 20-Year $/MWh, TPO)



- According to SEA's modeling, solar PV projects sited on brownfield parcels carry a relatively tight incremental cost range of $25-$28/MWh (2.5-2.8 ¢/kWh), depending on the size of the project. This compares to a current SMART statewide tranche value of $30/MWh (3.0 ¢/kWh).
- SEA's modeling also suggests that if projects are eligible for a 10% bonus "energy communities" tax credit, their incremental costs are reduced to $7-$8/MWh (0.7-0.8 ¢/kWh), depending on the size of the project.
- The main drivers of incremental costs for these projects are the remediation of the parcel, as well as slightly higher operating expenses and lower production estimates.
- The differences between sizes are relatively limited in significant part by the less significant scale and less-fixed nature of the incremental capital and operating costs relative to projects on landfill parcels.

Dual-Use Agricultural Solar (Base Cost, 20-Year $/MWh, TPO)



- During the most recent SMART program review, the Department proposed, and the Department of Public Utilities (DPU) approved, changes to the SMART program to allow dual-use agrivoltaics.
- The incremental revenue requirements for these projects over 20 years relative to a greenfield, ground-mounted system are driven largely by:
    - The incremental upfront installed cost of agricultural canopy racking and mounting; and
    - Reduced production due to non-optimal tilts and azimuths required for siting canopy structures on agricultural land.
- To date, there have been relatively few projects utilizing this adder brought to commercial operation. This relative lack of activity is due in part to the BCR misalignment discussed earlier in this report, but also to a misalignment of the incremental costs of these projects to available adder values.
- ¢EA's modeling suggests that solar PV projects that utilize agricultural canopy systems to allow for the simultaneous cultivation of crops parcels require approximately $74-$79/MWh (7.4-7.9 ¢/kWh) more revenue on a nominal basis in 2025, depending on the size of the project. This compares to a current SMART statewide tranche value of $60/MWh (6.0 ¢/kWh).

Levelized Incremental Revenue Requirements for Projects in Offtaker/Income-Based SMART Market Subsectors

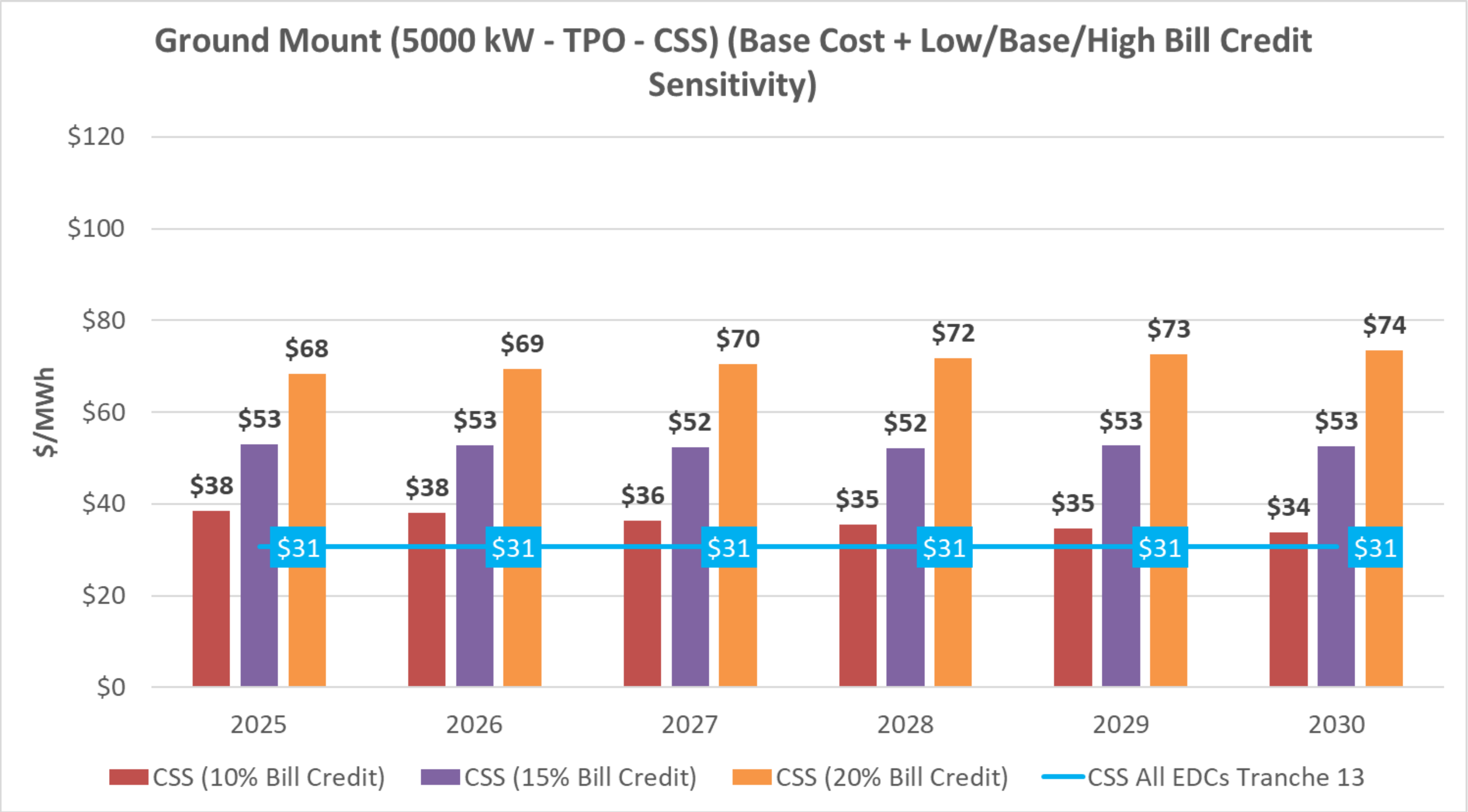
Solar PV Projects Greater than 25 kW_{AC} and Less than or Equal to 5 MW_{AC}

Sustainable Energy Advantage, LLC

Overarching Observations: Levelized Incremental Costs For Solar PV Projects in Offtaker-Based Market Subsectors

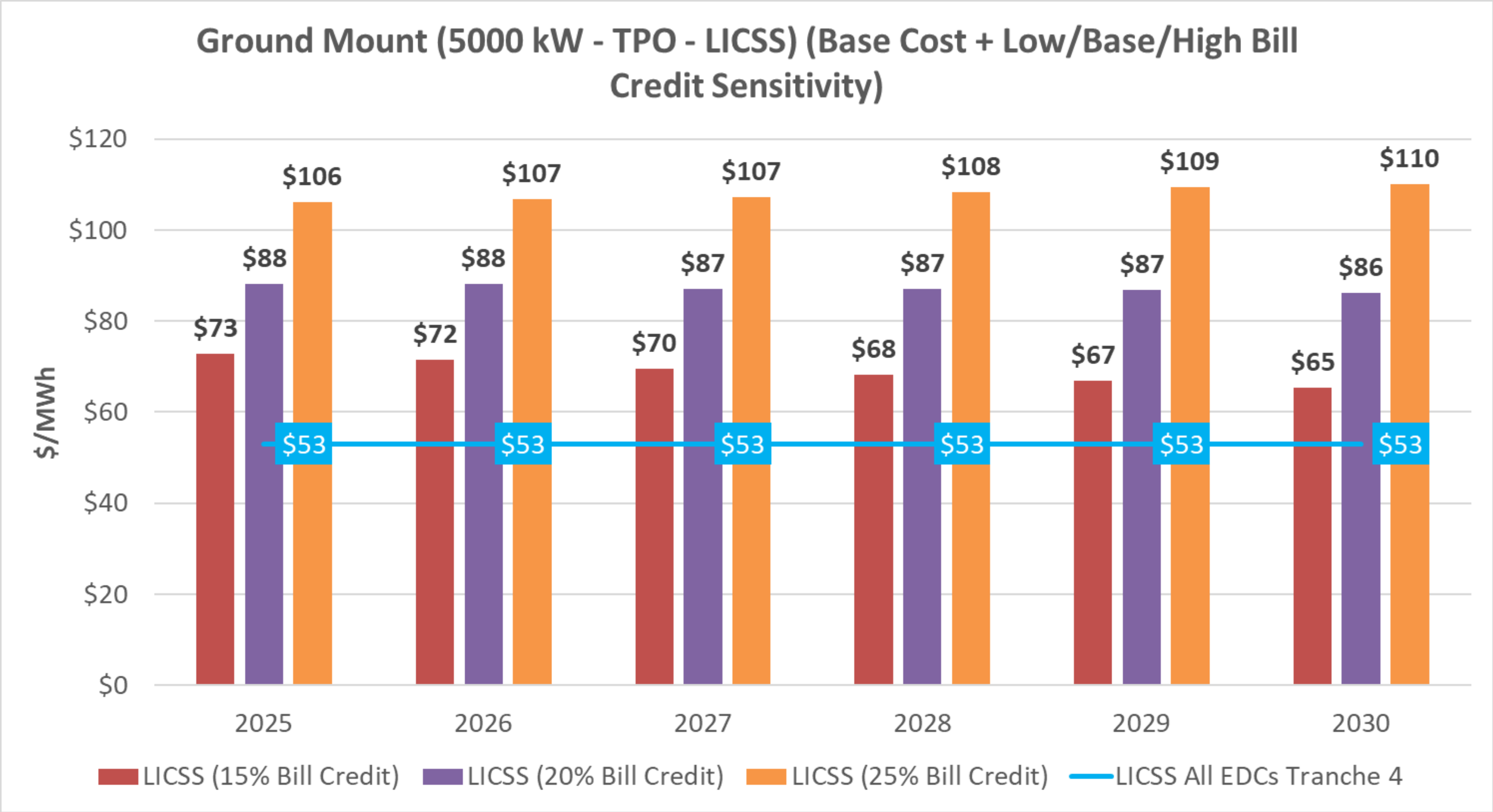
- The main drivers of community solar incremental cost difference from Base Cost ground-mounted projects are:
  - The upfront cost of customer acquisition;
  - The ongoing cost of customer care and billing; and;
  - The incremental cost to developers to providing a bill credit to an authorized customer.
- The incremental cost of low-income community solar projects remains higher, owing to the added cost of customer acquisition for low-income customers, as well as the larger size of the required bill credit.
- The availability of the 20% incremental Investment Tax Credit (ITC) for low income/disadvantaged community projects makes it feasible for the current adder value to be sufficient compensation (assuming an appropriately-aligned BCR).
- However, it is unclear that the U.S. Environmental Protection Agency's and U.S. Department of Energy's process to select such projects (as will be the implementation of the IRA) will result in many low-income community solar projects in Massachusetts being selected.
- Low Income Property Solar projects require less incremental levelized revenue than low-income community solar projects, but their costs vary significantly by size based on market participant feedback.

Community Shared Solar (Base Cost, 20-Year $/MWh, TPO, Low/Base/High Bill Credit Cost)



- For market-rate community solar projects, SEA's modeling suggests that the nominal incremental levelized cost of these projects in 2025 ranges from $38-$68/MWh (3.8-6.8 ¢/kWh), assuming a customer bill credit range from 15%-25% of their retail rate.
- The current SMART statewide tranche value for community solar projects is $31/MWh (3.1 ¢/kWh), which suggests that the typical range of discounts customers tend to accept remains nearly $10/MWh (1 cent/kWh) above current compensation levels.
- The main drivers of community solar incremental cost difference from Base Cost ground-mounted projects are:
  - The upfront cost of customer acquisition;
  - The ongoing cost of customer care and billing; and;
  - The incremental cost to developers to providing a bill credit to an authorized customer.
- These costs do not substantially differ by size of the project, and as such, their incremental levelized cost decreases with the size of said project.

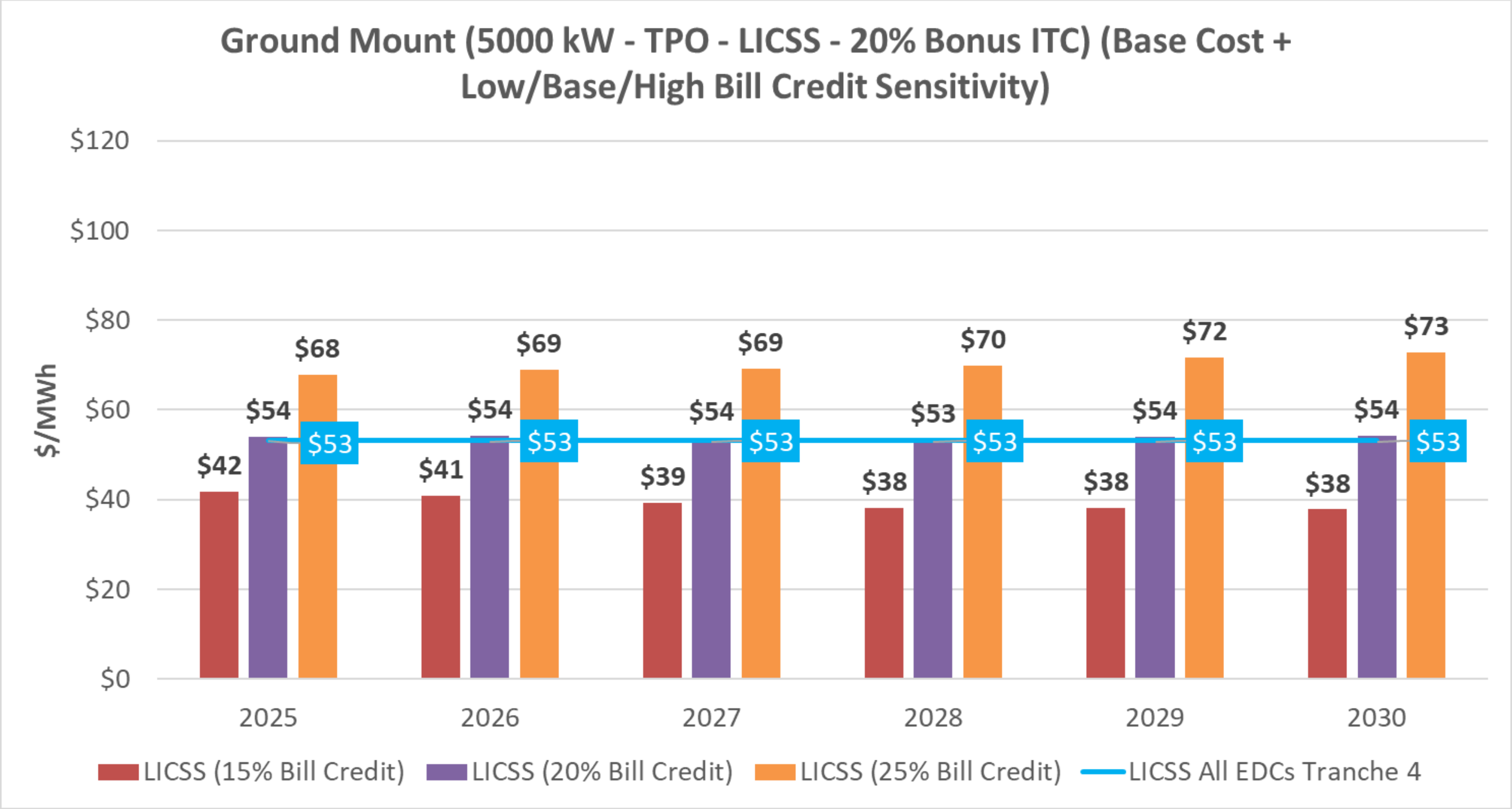
Low Income Community Shared Solar (Base Cost, 20-Year $/MWh, TPO, Low/Base/High Bill Credit Cost)



NOTE: It is our understanding based on industry practice that a minimum 15% (and upwards of 25%) bill credit is often required to induce the participation of low-income customers in solar PV projects. We further note that the minimum required bill credit to be eligible to receive a 20% bonus Investment Tax Credit (ITC) value under the IRA for a <5 MW_{AC} project is 20% of a low-income customer's retail rate, which is often lower than the rate available for market-rate customers.

- For community solar projects with at least 50% offtake consisting of low-income customers, SEA's modeling suggests that the nominal incremental levelized cost of these projects in 2025 ranges from $73-$106/MWh (7.3-10.6 ¢/kWh), assuming a customer bill credit range from 15%-25% of their retail rate (see Note at left).
- The current SMART statewide tranche value for low-income community solar projects is $53/MWh (5.3 ¢/kWh), which suggests that the typical range of discounts low-income customers tend to accept remains between $20-$50/MWh (2-5 ¢/kWh) above current low-income community solar incremental compensation levels.
- The main drivers of higher low-income revenue requirements relative to market-rate community solar is the added cost of customer acquisition for low-income customers, as well as the larger size of the required bill credit (as described in the Note at left)
- These costs do not substantially differ by size of the project, and as such, their incremental levelized cost decreases with the size of said project.

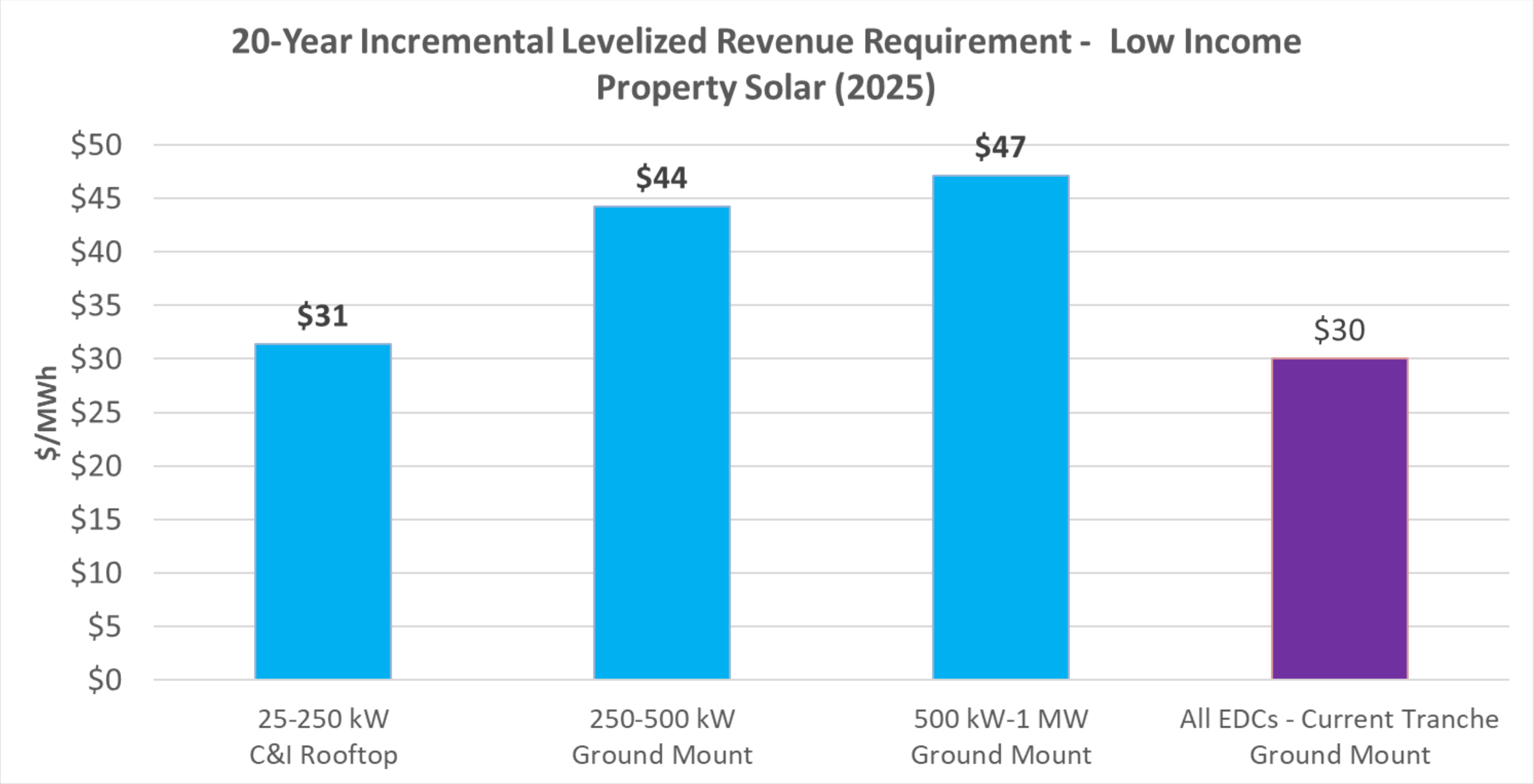
Low Income Community Shared Solar + 20% Bonus ITC (Base Cost, 20-Year $/MWh, TPO, Low/Base/High Bill Credit Cost)



NOTE: It is our understanding based on industry practice that a minimum 15% (and upwards of 25%) bill credit is often required to induce the participation of low-income customers in solar PV projects. We further note that the minimum required bill credit to be eligible to receive a 20% bonus Investment Tax Credit (ITC) value under the IRA for a <5 MW_{AC} project is 20% of a low-income customer's retail rate, which is often lower than the rate available for market-rate customers.

- For community solar projects with at least 50% offtake consisting of low-income customers that receive a 20% bonus ITC under the IRA for serving a low income and/or disadvantaged community, SEA's modeling suggests that the nominal incremental levelized cost of these projects in 2025 ranges from $42-$68/MWh (4.2-6.8 ¢/kWh), assuming a customer bill credit range from 15%-25% of their retail rate (see Note at left).
- Therefore, it is reasonable to suggest that, for such projects able to qualify for the 20% low income/disadvantaged community bonus credit, the adder value currently available would match the incremental revenue requirement of such a project if participating customers were offered a 20% bill credit.
- That said, it is unclear whether projects in Massachusetts will be selected in the U.S. Environmental Protection Agency or Department of Energy's process, or to what degree such projects reflect most of the pipeline of low-income community solar projects.

Low-Income Property Solar (Base Cost, 20-Year $/MWh, TPO)



- For projects serving on-site loads for low-income properties, SEA's modeling suggests that the incremental revenue requirement of serving such customers ranges between $31-$47/MWh (3.1-4.7 ¢/kWh).
- These values compare to a current statewide tranche value for such projects of $30/MWh (3.0 ¢/kWh).
- The key incremental revenue requirement drivers in this sector are the incremental customer acquisition costs for project developers looking for offtakers that own low-income properties, as well as the low-income tenants on those properties.
- The relative incremental cost difference between the size categories is driven mainly by slight differences in the incremental costs reported by subsector. As such, it is possible that an average of these values would be a more accurate reflection of incremental cost.

Levelized Incremental Revenue Requirements for Solar PV + Energy Storage Projects

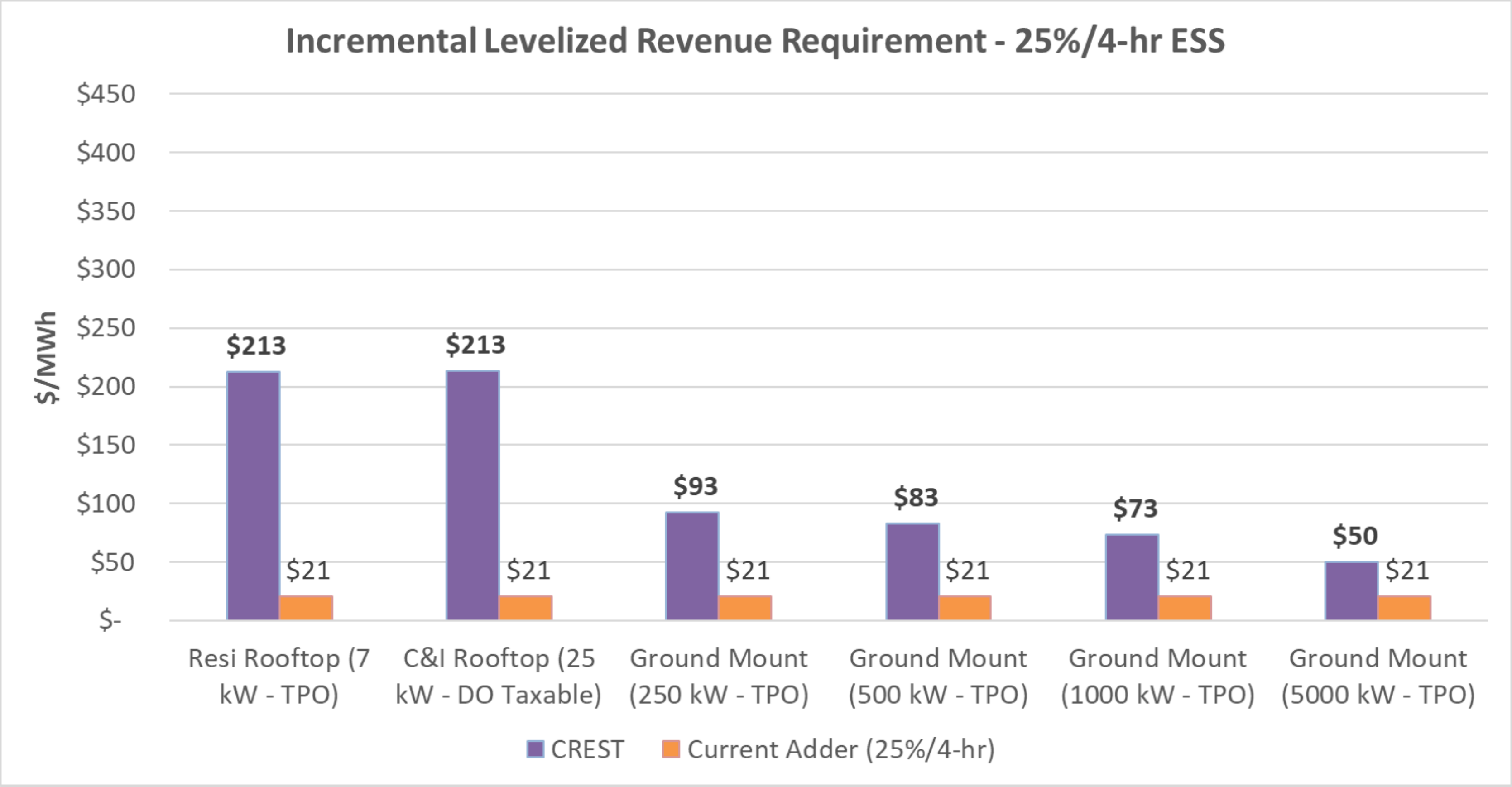
Solar PV + Energy Storage Projects Less than or Equal to 5 MW_{AC}

Sustainable Energy Advantage, LLC

Overarching Observations: Levelized Incremental Revenue Requirements for Solar PV + Energy Storage Projects

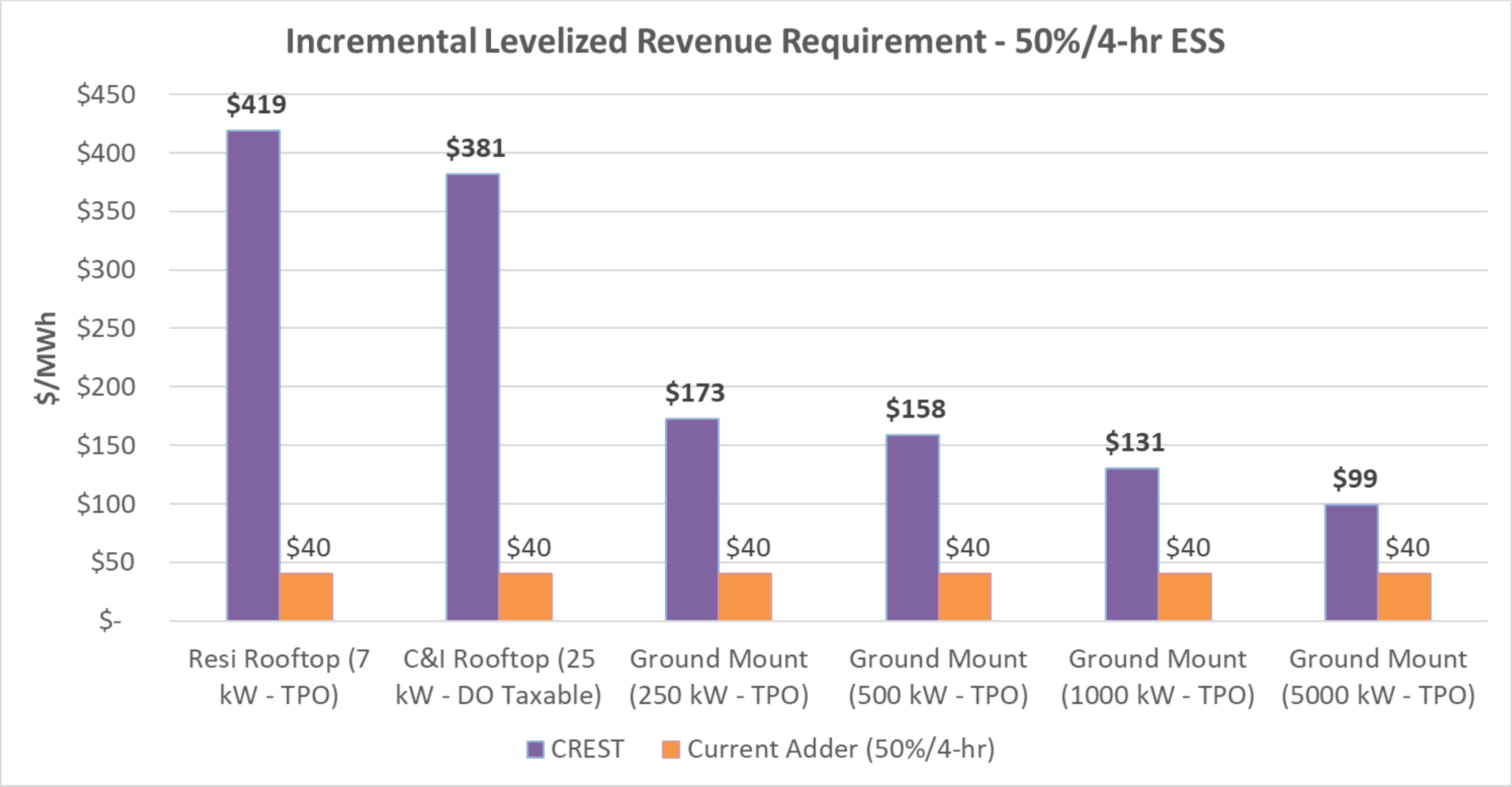
- The analysis requested from SEA by DOER concerns the incremental cost of solar PV projects paired with energy storage systems (ESS) of varying capacities. However, it is our understanding that the current Compensation Rate Adders in this segment were developed in part based on the value of various energy storage projects of different sizes back when the program initially began. The analysis of these values was not originally carried out by SEA at that time.
- Without accounting for other potential revenue streams associated with such projects, in terms of incremental levelized costs, <=25 kW_{AC} solar PV projects paired with ESS have dramatically higher incremental costs than their current statewide tranche value, while >25 kW_{AC} solar PV projects paired with ESS have much lower incremental levelized costs.
- To determine the incremental levelized costs net of these revenue streams, further analysis is required.

Community Shared Solar/Low-Income Community Shared Solar (CSS/LICSS, Base Cost, 20-Year $/MWh, TPO)



- For solar PV projects >25 kW_{AC} paired with energy storage projects equivalent to 25% of the PV system's rated power over four (4) hours, SEA's modeling suggests that these projects have incremental revenue requirements ranging from $50-$93/MWh (5.0-9.3 ¢/kWh), without accounting for other revenue streams associated with such projects.
- For solar PV projects <=25 kW_{AC} paired with energy storage projects equivalent to 25% of the PV system's rated power over four (4) hours, SEA's modeling suggests that these projects have incremental revenue requirements of $213/MWh, without accounting for other revenue streams associated with such projects.
- These values compare to a statewide tranche value of $21/MWh (2.1 ¢/kWh).
- The key drivers of incremental cost from ground-mounted projects of a similar size are the capital and operating costs associated with the energy storage system (ESS).
- The difference in incremental cost by size can be ascribed to the economies of scale in both ESS capital and operating costs.

Community Shared Solar/Low-Income Community Shared Solar (CSS/LICSS, Base Cost, 20-Year $/MWh, TPO)



- For solar PV projects >25 kW_{AC} paired with energy storage projects equivalent to 50% of the PV system's rated power over four (4) hours, SEA's modeling suggests that these projects have incremental revenue requirements ranging from $99-$173/MWh (9.9-17.3 ¢/kWh), without accounting for other revenue streams associated with such projects.
- For solar PV projects <=25 kW_{AC} paired with energy storage projects equivalent to 50% of the PV system's rated power over four (4) hours, SEA's modeling suggests that these projects have incremental revenue requirements of $381-419/MWh, without accounting for other revenue streams associated with such projects.
- These values compare to a statewide tranche value of $40/MWh (4.0 ¢/kWh).
- The key drivers of incremental cost from ground-mounted projects of a similar size are the capital and operating costs associated with the energy storage system (ESS).
- The difference in incremental cost by size can be ascribed to the economies of scale in both ESS capital and operating costs.

Key Task 1 Takeaways for Future Program Development

Avoidance of Future Cost/Compensation Misalignments

- As noted in this report, the most significant drivers of the current misalignment between SMART compensation and solar PV (and PV plus storage) installed capital costs and financing costs (particularly interest rates on term debt).
- However, SEA observes that the full differential/misalignment cannot be explained by changes in costs in the market alone.
- Indeed, a very significant driver of misalignments of this magnitude is 1) the requirement of automatic BCR reductions, even if costs have not necessarily been systematically declining and 2) the limited opportunities available to DOER to adjust these compensation values as market conditions change.
- Misalignments of this magnitude and persistence can only be avoided with mechanisms built into the SMART program regulations and approval processes that are responsive, at minimum, to significant changes in market, including:
  - Significant changes solar PV and storage capital costs (and, if necessary, operating costs) due to policy or macroeconomic changes affecting all market participants in a given sector; and
  - Financing costs driven by monetary policy.
- It may be reasonable for DOER, particularly if it is looking to add an additional tranche of SMART program capacity, to consider time- and capacity-denominated (rather than only capacity-denominated) plans similar to those developed by the Energy Efficiency Advisory Council for the MassSave program.

Other Key Task 1 Takeaways

- Awareness and Importance of Non-Economic Factors Regarding Certain Market Sectors
  - Projects benefitting low-income customers will likely require a mix of appropriate economic incentives (as described herein), as well as substantial non-economic efforts to reach such customers. Incentives due to non-economic factors will likely require a mix of added economic and non-economic incentives, and ones that address potential “split incentive” issues.
  - Non-economic outreach and facilitation efforts will likely also be required for potential non-taxable entity owners of solar projects that benefit from “direct pay” provisions in the Inflation Reduction Act of 2022, given the typical risk appetite of non-taxable entities such as local governments and non-profit entities.
- Solar PV with Paired Energy Storage
  - Further analysis will likely be required to establish appropriate incremental incentive values for solar PV projects paired with energy storage, given that the current incentives are non-cost-based incentives that reflected the value of the resource to the bulk power and distribution systems.
  - Appropriate incentives for paired solar PV and energy storage projects will likely need to reflect, at minimum, the other revenue sources such projects receive, at the bulk power and distribution system levels, as well as the timing of that revenue and any other approach to encourage appropriate price signaling.

Sustainable Energy Advantage, LLC
161 Worcester Road, Suite 503
Framingham, MA 01701
http://www.seadvantage.com