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New Jersey Solar Transition Draft Capstone Report

Successor Program Review

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Prepared for:

New Jersey Board of Public Utilities

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1. Executive Summary

New Jersey's Clean Energy Act (CEA) of 2018 directed the Board of Public Utilities (BPU) to develop a new program "to encourage the continued efficient and orderly development of solar renewable energy generating sources throughout the State." As part of the CEA, the BPU was required to prepare a report to the Governor and Legislature of New Jersey to recommend how best to replace the existing Solar Renewable Energy Certificate (SREC) market with a successor solar program (Successor Program) that would deliver improved solar performance at a reduced price. The Cadmus Group, LLC (Cadmus) was retained by the BPU to help conduct an extensive stakeholder-driven review of New Jersey's solar policies and to prepare this report.

This draft report reviews and analyzes options for the Successor Program. The report is organized as follows:

- Section 2 provides an overview of the process of closing the SREC program and the robust stakeholder engagement undertaken by the BPU and facilitated by Cadmus
- Section 3 reviews the development of incentive options for the Successor Program
- Section 4 discusses project- and market-level modeling performed for the Successor Program
- Section 5 reviews results of the modeling
- Section 6 provides recommendations for how best to design and implement a Successor Program that meets the statutory criteria set forth in the CEA

Key recommendations follow, drawn from our research and analysis of the prospective Successor Program incentive:

- Implement an "always on" fixed-incentive program, comparable to the existing Transition Incentive program, that that would provide strong certainty, business visibility, and especially "finance-ability." While complementing the net metering incentive for the near term, this incentive could evolve toward more of a Total Compensation paradigm if conditions warrant in the future (i.e., as a means to reflect more holistically the value of these projects to the market, grid, and environment).
- Maintain program flexibility with regularly planned re-evaluations, revisions, and changes on a fixed timetable, while providing the industry with enough line-of-sight to enable long-term investment in New Jersey's solar market.
- Deploy a mix of competitive solicitations, particularly for utility-scale solar projects, and use administratively set incentives for smaller-scale projects. This will enable market price discovery while establishing minimum incentive levels.
- Any administratively set incentives should employ a transparent process with (i) robust cost and technical assumptions that reflect timely data and stakeholder experience and expectations, and (ii) modeling that is flexible enough to incorporate various types of solar projects and that has been vetted by the market.

- Implement a policy that differentiates between project customer classes, installation types, locations, and technologies in order to deploy a robust and diverse fleet of projects. For example, variations in tariffs and interconnection costs across electric distribution company (EDC) service territories, along with differences in construction costs between solar installation types, can have significant impacts on overall project economics.
- Align incentives with other policies on an ongoing basis, including utility interconnection procedures, net metering, Federal Energy Regulatory Commission regulations, and tax policies.
- Further investigate existing (sub)segments in the solar market to identify, and seek to mitigate, where possible, impediments to growth.
- Investigate emerging technologies and new solar business models (e.g., energy storage, dual-use solar agriculture, floating solar, building-integrated photovoltaics, and project repowering), and ensure that the Successor Program is sufficiently flexible to adapt to such potential opportunities for solar expansion.
- Perform a technical and market potential study to assess the total, feasible capacity for solar in the State of New Jersey based on physical, technical, and market assessments.
- Evaluate initial incentives relative to those in the Transition Incentive to avoid market disruption in the transition to the Successor Program.
- Create stakeholder working groups that meet on a regular basis and focus on key issues for solar development, potentially including interconnection, permitting, and broader clean energy initiatives.

Overall, New Jersey has made a strong commitment to continuing to grow its solar industry. The 2019 Energy Master Plan (EMP) set ambitious targets for solar, suggesting that in-state solar would represent 34% of the State's generation mix to meet the state's 100% clean energy by 2050 goal. The Integrated Energy Plan (IEP) modeling suggests that New Jersey should seek to install 32 GW of in-state solar by 2050, with interim targets of 5.2 GW by 2025, 12.2 GW by 2030, and 17.2 GW by 2035. The Solar Transition aims to meet these goals efficiently and at the least cost to ratepayers.

As part of our analysis for a Successor Program, Cadmus has analyzed a range of solar project characteristics—customer types, installation types, ownership, size, and EDC territory—to explore how differentiation impacts project economics and minimum incentives. Further, we have constructed a variety of modeling tools to evaluate how different incentive strategies impact capacity and costs. For example, the models allow forecasting capacity in two ways: "bottom-up," by evaluating historical trends for different project types and assigning different growth rates; and "top down," where we assume capacity growth and adjust the mix of project types. Cadmus believes that, with these tools and analysis, in concert with stakeholder expertise and participation, the BPU will be able to direct the next generation of solar incentives efficiently while maintaining a strong, diversified solar industry.

2. Background and Summary of Stakeholder Engagement

2.1. Overview of the CEA and Resulting Closure of the SREC Market

Among other things, the Clean Energy Act (CEA) required that the existing SREC program be closed when solar generation comprised 5.1% of electricity sold in the state by electric power suppliers and basic generation providers (5.1% Milestone), and that the Board of Public Utilities (BPU) complete a study to evaluate "how to modify or replace the SREC program to encourage the continued efficient and orderly development of solar renewable energy generating sources throughout the State." Cadmus entered into an agreement with the BPU to provide advisory services in support of such a study, an assessment and recommendation for redesign of Solar Renewable Energy Certificate (SREC) Program.

In December 2018 and as subsequently refined, the BPU's Office of Clean Energy staff issued a straw proposal (Staff Straw) that outlined the main elements of the Solar Transition, including stakeholder engagement and the three solar programs for implementation, once attaining the 5.1% Milestone:

- **Legacy SREC Program** would capture projects that filed with the SREC Registration Program (SRP) and were deemed operational (i.e., attained their Permission to Operate (PTO) from their respective utility prior to attainment of the 5.1% Milestone).
- **Transition Incentive Program** would cover projects registered with the SRP by the 5.1% Milestone but not yet operational, as well as projects potentially registering after the 5.1% Milestone but before implementation of the Successor Program.
- **Successor Program** would comprise a new incentive for projects registering after the 5.1% Milestone.

The Staff Straw divided the Solar Transition into two phases:

- **Phase 1: Transition Incentive.** Comprised of stakeholder engagement and analytical work regarding design of the Transition Incentive. The work on the incentive's design was largely completed in December 2019. Related BPU Staff efforts, including modeling of the 5.1% Milestone attainment, closure of the Legacy SREC Program, implementation of the Transition Incentive Program, and the composition of the Cost Cap, have continued into 2020. Of note, much of the work during this phase (including a review of incentive structures and payment options and an analysis of project economics) was relevant to this and Phase 2.[1]
- **Phase 2: Successor Program.** Relates to the design of the Successor Program and is informed by stakeholder engagement, analysis, and modeling. This work began in December 2019, but, as

[1] For information about the analysis, stakeholder engagement, and BPU communications about the implementation of the Transition Incentive, as well as the closure of Legacy SREC Program, see the CEA Solar Transition Stakeholder Process section on the New Jersey Clean Energy Program website: https://njcleanenergy.com/renewable-energy/program-updates-and-background-information/solar-proceedings

indicated above, work performed during design of the Transition Incentive Program has informed this phase.

2.2. Overview of Stakeholder Engagement in the Successor Program

The New Jersey Solar Transition process incorporated extensive stakeholder engagement, including a mix of BPU-led and Consultant-led workshops, meetings, surveys, and written feedback that informed Cadmus' recommendations. Table 1 provides a high-level overview of stakeholder engagement activities that took place during the Solar Transition process.

Table 1. Summary of Stakeholder Engagement Activities

Date	Engagement Activity	Description	Lead
Initial Solar Transition Stakeholder Engagement			
12/26/18	Staff Straw Proposal	BPU released the Staff Straw Proposal that introduced the Solar Transition Principals and a list of 13 questions. Cadmus reviewed comments from stakeholders and summarized findings for BPU.	BPU
1/18/19	Stakeholder Meeting	BPU held a stakeholder meeting to discuss and hear from the solar industry about the Straw Proposal, released by BPU on December 26, 2018. The Cadmus team attended, took notes, and summarized comments for BPU.	BPU
2/22/19[2]	Stakeholder Meeting	BPU held a similar stakeholder meeting in February to continue receiving public comments on the Staff Straw Proposal. Cadmus staff attended.	BPU
Solar Transition Phase 1. Transition Incentive			
5/2/19	Stakeholder Workshop #1	The Consultants coordinated and facilitated the first of three stakeholder workshops. This workshop focused on identifying stakeholder priorities for the Solar Transition.	Consultants
June 2019	Cost & Technical Survey	The Consultants provided a list of questions to stakeholders related to project installation and operating costs as well as to incentive parameters.	Consultants
6/14/19	Stakeholder Workshop #2	The Consultants coordinated and facilitated the second of three stakeholder workshops. This workshop focused primarily on the Transition Incentive Program, but it introduced potential Successor Program policy pathways.	Consultants
7/31/19	Cost Cap Stakeholder Meeting	BPU conducted a stakeholder meeting to discuss the proposed method for calculating attainment of the 5.1% Milestone.	BPU

[2] This stakeholder meeting was originally scheduled for February 12, 2019, but was rescheduled due to inclement weather.

Date	Engagement Activity	Description	Lead
8/28/19	Stakeholder Meeting	BPU conducted a stakeholder meeting on the 2019/2020 Transition Incentive Staff Straw Proposal.	BPU
9/4/19	Stakeholder Meeting	BPU conducted a stakeholder meeting on the 2019/2020 Transition Incentive Staff Straw Proposal.	BPU
9/6/19	Technical Modeling Conference	BPU and the Consultants held a stakeholder meeting to discuss Transition Incentive modeling assumptions.	BPU/Consultants
10/11/19	Stakeholder Meeting	BPU and the Consultants held a stakeholder meeting to discuss the Revised 2019/2020 Transition Incentive Staff Straw Proposal and Modeling Addendum.	BPU
Solar Transition Phase 2. Successor Program			
12/17/19	Stakeholder Workshop #3	The Consultants coordinated and facilitated the third of three stakeholder workshops. This workshop focused on narrowing down policy pathways for modeling of the Successor Program.	Consultants
1/15/20	Stakeholder Meeting	BPU conducted a stakeholder meeting to discuss the CEA's statutory cost caps.	BPU
3/3/20	Stakeholder Meeting	BPU held a stakeholder meeting, during which they discussed the Successor Program's incentive design and sought feedback on Cadmus' modeling assumptions and proposed program types.	BPU
March 2020	Cost Survey	Cadmus provided questions for stakeholder feedback related to modeling assumptions.	Consultants
Week of 3/16/20	Focus Groups	BPU hosted calls with representative stakeholders grouped by category (e.g., developers, utilities).	BPU

The following sections summarize Phase 1 and Phase 2 stakeholder engagement activities that informed design of the Successor Program.

2.3. Phase 1. Transition Incentive

During the initial stakeholder activities in late 2018 and early 2019, it became clear that the solar market needed an interim program to provide predictability and stability until the Successor Program could be implemented. As such, the Transition Incentive was born, and most stakeholder activities in 2019 were dedicated to designing and gathering feedback on the proposed Transition Incentive. During the Transition Incentive activities, the Cadmus team discussed Successor Program aspects with stakeholders, as highlighted below.

Stakeholder Workshop #1 (SW #1) and Stakeholder Workshop #2 (SW #2) informed development of the Successor Program. During SW #1, the Cadmus team identified and prioritized stakeholder's objectives for the Successor Program. Following SW #1, the Cadmus team translated the Solar Transition Principles and the stakeholder objectives into primary and secondary design criteria to guide development of the Successor Program (as shown in Table 2, Table 3, and Table 4).

At SW #2, the Cadmus team presented and gathered final feedback on the design criteria and presented 12 potential policy paths for consideration for the Successor Program (shown in Table 5). After SW #2, the Cadmus team simplified and narrowed down the potential policy paths, which served as the basis for Stakeholder Workshop #3 discussions (see Phase 2).

Table 2. Translating Original Solar Transition Principles into Successor Program Design Criteria

Solar Transition Principle	Successor Plan Design Criteria
1. Provide maximum benefits to ratepayers at the lowest costs.	Maximize ratepayer benefits and/or minimize ratepayer costs.
2. Support continued growth of the solar industry.	Support solar industry growth, with an emphasis on community solar, rooftop, and landfill resources, while minimizing use of productive agricultural or forested lands.
3. Ensure prior investments retain value.	The Successor Program is designed for new projects, though projects constructed under legacy solar programs are excluded.
4. Meet the Governor's commitment of 50% Class I Renewable Energy Certificates (RECs) by 2030 and 100% clean energy by 2050.	Meet IEP targets of ~12.2 GW of solar by 2030, with the goal of 100% of New Jersey's hourly load served by renewables by 2050.
5. Provide insight and information to stakeholders through a transparent process for developing the Solar Transition and Successor Program.	Convene meetings and other stakeholder outreach to disseminate knowledge and information.
6. Comply fully with the statute, including the cost cap's implications.	Binding constraint: comply with the cost cap and maintain flexibility to incorporate findings of the cost cap proceeding.
7. Provide disclosure and notification to developers that certain projects may not be guaranteed participation in the current SREC program, and continue updates on market conditions via the New Jersey Clean Energy Program (NJCEP) SRP Solar Activity Reports/	BPU provided notice to SRP applicants.

Table 3. Translating Higher Priority Stakeholder Objectives into Primary Successor Program Design Criteria

Stakeholder Objective	Successor Plan Design Criteria
1. Fairness to those making past commitments and those making future ones.	Seek fairness for those making future commitments.
2. Transparency.	Provide transparency and clarity regarding pricing and project eligibility.
3. Minimize market disruption.	Provide timely guidance on program details.
4. Support steady industry growth.	Support steady industry growth.
5. Favor support to open or rolling market incentives vs. scheduled procurements.	Maximize certainty of incentive access.
6. Minimize complexity.	Minimize complexity.
7. Focus on feasible implementation.	Ensure feasibility.

Table 4. Translating Other Priority Stakeholder Objectives into Secondary Successor Program Design Criteria

	Stakeholder Objective	Successor Plan Design Criteria
1.	Ensure cost-effectiveness.	Maximize cost-effectiveness (MW/ratepayer $).
2.	Minimize ratepayer impacs.t	Minimize ratepayer impacts and/or maximizes ratepayer net benefits (including environmental considerations).
3.	Transition to a sustainable market by reducing incentives over time.	Reflect current and forecast market pricing, which should decline over time.
4.	Balance solar development between the built environment and green space.	Maximize solar development on disturbed land/minimizes reliance on green space.
5.	Encourage installation type diversity.	Encourage installation-type diversity.
6.	Minimize financing risk.	Minimize financing risk.
7.	Encourage participant diversity.	Encourage participant diversity.
8.	Create and keep permanent in-state jobs.	Maximize near- and long-term jobs in NJ.
9.	Prioritize competitive market structures.	Maximize use of competitive market mechanisms and compatibility with competitive wholesale and retail markets.
10.	Accelerate implementation and the timeliness of transition.	Allow timely implementation.
11.	Support PV location where most needed.	Support PV location where most needed.

Table 5. Potential Successor Program Policy Paths

Path #/Name/Theme:	Summary Description
SP-1. Minimize disruption: Same Game, New Ballpark	Separate RPS tier for solar (SREC II) (large & small)
SP-2. Minimize disruption with differentiation: Factorized[3] SRECs	Separate RPS tier for solar (SREC II) with SREC factors (large & small)
SP-3. Minimize disruption with differentiation: Factorized SRECs with Soft Floor	Separate RPS tier for solar (SREC II) with SREC factors with Soft Floor (large & small)
SP-4. Minimize disruption with differentiation: Factorized SRECs with Firm Floor	Separate RPS tier for solar (SREC II) with SREC factors with Firm Floor (large & small) Parallel unlimited firm floor price mechanism (via Buyer of Last Resort)
SP-5. Minimize disruption with differentiation and price stability: Factorized SRECs with an SREC Buyback Program	Separate RPS tier for solar (SREC II) with SREC factors (large & small) Parallel limited firm floor price mechanism (quantity-limited RFP/buyback)
SP-6. Declining Block Incentive for all w/ Administrative Price setting	Cost-Based Performance-Based Incentive (PBI) Tariff: Admin-established initial price (large & small differentiated); Declining block incentive; w/ MW cap
SP-7. Declining Block Incentive for all w/ Competitive Price setting	Competitively Derived PBI Tariff: Initial competitively established price for large systems, with small system price established as a function of large competitive price; Declining block incentive; w/ MW cap [MW block variant]
SP-8. Adjustable Block Incentive for all w/ Competitive Price setting	Competitively Derived PBI Tariff: Initial competitively established price for large systems, with small system price established as a function of large competitive price, with small price established as a function of large competitive price; Time-based Adjustable Block Incentive; w/ MW cap
SP-9. PBI with Periodic Administrative Price Reset for all	Cost-Based PBI Tariff: Periodically administratively established price (large & small differentiated); w/ MW cap
SP-10. Ongoing competition for large, cost-based administratively set PBIs w/ periodic reset for the rest	Cost-Based PBI Tariff: Periodically Admin-established price (Small) RFP/Auction/Tender Competitive Long-Term Power Purchase Agreements (PPAs) (large or largest)
SP-11. Ongoing competition for large, cost-based Declining Block Incentive for the rest	Cost-Based PBI Tariff: DBI w/ administratively established initial price (small); RFP/Auction/Tender Competitive Long-Term PPA (large or largest)
SP-12. Ongoing competition for large/ Grid-Supply; Value of Solar for all others	Hybrid Value-based/Administratively set PBI (small) RFP/Auction/Tender Competitive Long-Term PPA (large grid-supply)

3 Different types of solar PV projects receive different subsidy levels.

2.4. Phase 2. Successor Program

Following the finalization of the Transition Incentive, the Cadmus team shifted to developing the Successor Program. The Successor Program's design process included Stakeholder Workshop #3 (SW #3), a BPU led stakeholder meeting, a cost survey, and a series of focus group sessions.

Stakeholder Workshop 3

The aim of SW #3 was to present and gather stakeholder feedback on a simplified and narrowed list of policy design issues and options initially discussed during SW #2. During the workshop, the Cadmus team presented policy design options for consideration in the Successor Program, provided examples from other markets, and discussed the advantages and drawbacks of the different design options.

In breakout groups, stakeholders discussed the policy design issues and options, and they ranked their preferred approaches. Table 6 summarizes the policy design preferences of workshop participants.

Table 6. SWS#3 Summary of Policy Design Issue and Option Preferences

Policy Design Element	Option	Total Votes
Incentive Type: the incentive is fixed or is based on market supply and demand	Tradable Market Mechanism (e.g., RECs)	16
	Performance Based Incentive (Fixed Incentive amount)	**27**
	Both – differentiate by segment	2
Payment Structure: mechanism through which incentives are delivered	Separate Contract	8
	Utility Tariff	**17**
	Premium PBI	12
Price Setting Mechanism: upfront price setting	**Standard Offer**	**22**
	Competitive Solicitation	8
	SREC Market Based	17
Price Adjusting Mechanism: subsequent updates	Administrative Review	4
	Pre-Set Blocks	**21**
	SREC Market Based	9
Compensation Structure: the incentive reflects a premium over energy/capacity revenues, all revenue streams, or a hybrid	Premium (beyond energy/capacity, correlates to Fixed Incentive herein)	11
	Fixed Price (compensates for energy/capacity and premium)	**17**
	Fixed Compensation (Total Compensation herein)	3

Based on SW #3 input and previous stakeholder feedback from Phase 1, Cadmus identified the following policy paths for analysis (see Sections 3 through 5 for detailed discussions of the Successor Program policy paths and modeling):

1. Total compensation based on MWh
    a. Incentive fills gap (if any) between other value streams and total compensation
    b. Includes adders (and subtractors), like factors

2. Market-Based RECs: Similar to Legacy SRECs with a carve-out obligation, Solar Alternative Compliance Payments (SACP), etc.
    a. Factored RECs like Transition Incentive
    b. Hard floor set administratively
3. Feed-In Tariff: Fixed rate for energy plus a premium, reflecting environmental and other solar benefits
    a. Replaces net metering, SRECs, and other market-based value streams
4. Fixed Incentive: Fixed payment for MWh, representing a premium over energy and reflecting environmental and other solar benefits
    a. Rates decline (probably) based on MW blocks
    b. Can also be factored

Stakeholder Meeting

On March 3, 2020, the BPU led a stakeholder meeting focused on the Successor Program and asked for feedback regarding Cadmus' modeling assumptions and proposed program types. The questions for stakeholders to address at the meeting and during the subsequent comment period were grouped into four topics:

1. **Successor Program Incentive Design**, including advantages, drawbacks, and differences among the three incentive types (discussed under Section 3); incentive term; setting and revising incentive levels; and market-based recovery mechanisms.
2. **MW Targets and Program Capacity**, including project categories and how to set their capacity targets; participation and capacity reallocation protocols; and eligibility of projects located in municipal utility territories or outside the state.
3. **Grid Supply Solar**, including whether to require a special review process, whether a cap should be implemented, and the best means to incentivize rooftop, grid-supply projects.
4. **Solar Siting**, including differentiated incentives based on land types.

Some observations from Cadmus' review of the stakeholder comments follow, focusing on incentive design preferences:

- Incentive preferences:
    - Stakeholders representing developers and other industry players generally preferred the Fixed Incentive, following in kind from development of the TREC mechanism and providing a good level of certainty for planning and financing. Some pointed to Total Compensation as providing the greatest certainty (and therefore the best "finance-ability"), but participants also recognized the greater complexity involved and the potential for a broader set of regulations required. Generally, these stakeholders did not favor the market-based incentive due to volatility, inability to monetize the full value of RECs, required regulatory/political interventions, and the many "levers" involved.

    - Some electric distribution companies (EDCs) and representatives from SREC market intermediaries favored a market-based approach, similar to the Legacy SRECs. Referenced benefits included the market's familiarity with the Legacy SREC program, historic success at building the state's solar market, the ostensible ability to adjust to market conditions, and compatibility with other state competitive markets.
- Price-setting mechanisms:
    - The general idea that very large projects should be competitively procured; some cautioned, however, that auctions could result in unrealistic and unsustainable bids in a "race to the bottom."
    - Broad support for administratively set prices, at least for smaller projects. A strong preference emerged, however, for such processes to remain transparent and collaborative.
    - Issues with block programs, given developers may try too hard to procure projects in earlier blocks, potentially sacrificing quality.
- Term: Generally, respondents preferred longer terms, even wanting the incentive to line up closer to PPA terms and/or even the project life (i.e., 20–25 years).
- Project size limits: Some favored limiting the Successor Program incentive to projects of ~5–10 MW, with larger projects subject to another program.
- Differentiation: Generally favored differentiation by project and customer types, with caveats noting that too much differentiation could cause confusion. Stakeholders also discussed new segments and factors:
    - Dual-use projects (solar installed on agricultural land and integrated with active crops to some extent)
    - Storage co-located with solar
    - Floating solar (solar installed on floating platforms on bodies of water, such as lakes and reservoirs)
    - Building-integrated PV (solar integrated into the building envelope [for example, in lieu of a façade, roofing, or glass]).
- Ownership: A couple of utilities suggested EDCs should be allowed to invest in solar (for example, as with PSE&G's Solar 4 All program). This may provide a valuable segment (such as projects located near utility infrastructure and paired with storage). Projects not located on utility-owned parcels, however, could cannibalize private solar development.

Cost Survey

As an add-on to the March 2020 meeting and comment period, Cadmus provided BPU with a list of 40 technical questions for stakeholders. These questions, meant to follow-on the earlier technical and cost surveys, were primarily intended to inform growth assumptions for inputs, given the Successor Program's longer duration. Receiving several responses, Cadmus incorporated feedback into the Successor Program Model, as discussed in Section 4.

Focus Groups

During the week of March 16, 2020, BPU sponsored and led four focus groups with stakeholders. These focus groups were organized by broad stakeholder perspectives:

- Utility customers and customer advocates
- Solar industry—e.g., developers, capital providers, EPC, operations and maintenance (O&M) agents
- Utilities and load-serving entities

Discussions primarily sought feedback from stakeholders on additional program elements under consideration, but also were customized towards the specific interests of respective focus groups. The following section summarize comments made by these stakeholder groups (though not necessarily the positions of the Consultants or the BPU).

Focus Group 1: Utility Customers and Customer Advocates

- Siting
  - Stakeholders noted that the BPU should continue paying attention to siting issues, ensuring that siting-based incentive decisions do not conflict with other state goals and intentions.
- Education
  - Stakeholders suggested that communities need to learn more about solar to become more comfortable with the projects. Penetrating the learning curve poses a higher cost in low-income communities, though they receive the greatest benefits.
  - Solar projects' visibility proves important in communities and schools, especially as a learning tool for students.
- Community Solar
  - *Low-to-moderate income (LMI) incentives*. Stakeholders stressed the importance of setting aside projects focused on LMI communities and of having higher incentives for community solar in LMI communities; additionally, New Jersey could consider Massachusetts and Illinois as incentive examples.
  - *Environmental and economic benefits*. Community solar produces many ripple effects, including economic and environmental benefits.
  - *Fixed savings*. A fixed savings amount, regardless of the utility rate, is required to attain sufficiently high subscription rates.
  - *Consolidated billing.* Community solar does not currently have consolidated billing, offering a separate bill.

Focus Group 2: Solar Industry (developers, capital providers, EPC, O&M, agents), First Group

- **Policy Design Process.** Industry representatives wanted an opportunity to design something that achieved the State's policy goals in a way best for the industry.

- **Price-Setting Mechanism.** Participants questioned how prices would be set. The industry prefers an administratively set price to work, but the process must be informed by industry voices and must ensure full transparency in order to function.
- **Compensation Structure.** The New Jersey model must examine total compensation, as did Massachusetts.
- **Diversity.** The solar industry is active in various market segments, and focus group stakeholders thought this diversity must be incorporated into BPU's thinking.
- **Residential Sector Considerations.** Two new developments emerged in the residential sector:
  - The new fire code will reduce the size of residential systems by 30%–40%, in comparison to commercial systems.[4]
  - Most industry jobs are created in the residential sector, and these new developments particularly affect small businesses.
  - Stakeholders argued that it will be difficult to meet increasing generating capacity requirements without significant changes to incentives (unlike the past, when BPU routinely exceeded the goals).
- Transition to Successor Program:
  - The Transition Incentive program must align properly with the Successor Program's beginning, so it suits all segments of the industry equally.
  - The industry prefers incremental changes rather than dramatic adjustments with new programs. They suggested that transitioning to the Successor Program could be as easy as starting with the Transition Incentive Program and adding to it.
  - Stakeholders noted that national- and state-level research shows the industry is experiencing significant delays in supply chains and other disruptions due to COVID-19, which should be considered when designing the Successor Program.

Focus Group 3: Solar Industry (developers, capital providers, EPC, O&M, agents), Second Group

- Policy design and process considerations:
  - Industry stakeholders said simplicity has worked in the past and should happen in the future.
  - Parties would like to see the BPU pay more attention to the Transition Incentive timeline, ensuring that interested parties have sufficient time to provide feedback.

[4] Cadmus understands that, on September 3, 2019, New Jersey adopted the 2018 version of the International Residential Code (2018 IRC), which replaced the 2015 IRC. The 2018 IRC introduced certain setback requirements for rooftop solar systems in Section R324.6, including (i) at least two 36-inch pathways from the lowest roof edge to a ridge with at least one on the street or driveway side; and (ii) a 36-inch setback at the roof ridge if the array comprises more than 33% of the roof area (otherwise, 18 inches is required).

  - Participants noted that low-income and environmental justice communities are interested in receiving incentives, but they do not know how they work; consequently, they should be engaged now to involve them in the Successor Program.
  - In addition, incentives should encourage in-state job creation, tax revenues, economic development, and environmental benefits.
- Market mechanism. One participant was very adamant about the importance of a competitive, open market.
- Market mechanism with price certainty. Another participant agreed that a market-based approach would be ideal, but, in the State's current situation, there must be a guarantee of some policy and price certainty within the industry. Therefore, the participant recommended performance- or tariff-based incentives.

Focus Group 4: Utilities and Load-Serving Entities

- Transition Incentive:
  - Stakeholders said that, during discourse on the Transition Incentive, having a strong proposal on which to base comments proved helpful.
  - Participants heard concerns from the industry on how TRECs and implementation of the eventual program will affect Class I compliance.
  - Stakeholders noted that shifting compliance from the supply-side to the "wire-side" will make compliance easier. Many suppliers, however, buy RECs well in advance, making it difficult to predict the load or how many RECs are necessary to meet regulatory requirements without triggering Alternative Compliance Payments (ACPs).
- Large-scale solar.
  - Even if the Successor Program is opened to large-scale solar, those projects should be able to receive Class I RECs, and there should be a competitive bidding program for in-state, utility-scale solar.
  - Utilities should have a specific role in increasing utility-scale, grid-connected solar.
- Working groups. New York has found that maintaining technical and policy working groups has been useful in working through interconnection and other issues.

3. Incentive Option Development

BPU enlisted the Cadmus Team to identify new incentive mechanisms and their associated program components for New Jersey's Solar Transition Incentive and Successor Program. Based on input from BPU Staff and on a diverse set of stakeholders, the Cadmus Team identified Successor Program design criteria, reviewed a range of potential incentive design options, and chosen the top three policy paths for more in-depth consideration.

3.1. Identify Successor Program Incentive Design Criteria

Establishing appropriate design criteria is an essential first step in evaluating potential incentives to drive the deployment of cost-effective solar projects in New Jersey. As discussed, the Cadmus team pulled from two key sources in establishing design criteria:

1. The "Solar Transition Principles," outlined in the BPU New Jersey Solar Transition Staff Straw Proposal issued December 26, 2018.
2. Program objectives, as prioritized by stakeholders during Stakeholder Workshop #1.

As shown in Table 2 and Table 4, the Consultants translated Solar Transition Principles and higher-priority stakeholder objectives into "primary" Successor Plan design criteria, while lower-priority stakeholder objectives were designated as "secondary" Successor Plan design criteria, as shown in Table 4.

3.2. Review Range of Potential Design Options

The process for analyzing Successor Program incentive design options begins with a broad list of potential solar incentives utilized in other markets. Table 7 displays incentive types potentially applicable to the Successor Program. These include examples of implemented programs, which provide such incentives along with comments on those types of incentives. State postal abbreviations are used for those markets.

Table 7. Potential Incentive Types

Incentive Type	Reference Incentives	Additional Comments
Direct Upfront Incentive	MA Pre-SREC I rebates; NJ CORE and REIP rebates	Very high-cost incentive structure.
Total Compensation	MA SMART; RI REG	Discussed below.
Fixed Performance-Based	CT ZREC; NY-SUN C&I MW Block; IL Adjustable Block Program; CA Solar Initiative; NJ TREC	Discussed below.
Long-Term Value of Solar	NY VDER; Austin Energy (TX) Value of Solar tariff	Difficult to implement in a short period of time. NY VDER is a continual work in progress.
Market-Based RECs without Floor	NJ SREC; MD SREC	Without a price floor, SREC prices can collapse. Large solar carveouts can mitigate this risk.
Market-Based RECs with Floor	MA SREC I & II	Both policies have an auction floor price that represents a form of partial hedge.
Emission Markets	CA Cap-and-Trade; RGGI	Exogenous; accounted for in energy prices specific to NJ zones.

Incentive Type	Reference Incentives	Additional Comments
Expenditure-Based Tax Incentives	Federal solar investment tax credit (ITC)	Exogenous; accounted for in project economics.
Net Metering Crediting Mechanism	Multiple states	Co-incentive; accounted for in calculation of total revenue streams per project.

3.3. Incentive Types Chosen

Based on stakeholders' input from Stakeholder Workshop #3 and on the evaluation of all potential incentive types against the design criteria outlined in Section 3.1, the Cadmus team focused on three selected incentive types:

- Total Compensation
- Fixed Incentive
- Market-Based RECs with Floor

An overview of each incentive type, including key advantages, key disadvantages and program design elements, follows.

Total Compensation Incentive

A "total compensation" incentive is a type of performance-based incentive that utilizes a tariff payment structure, where the incentive acts like a contract for differences between the value of energy and the total compensation value paid to eligible projects. Total compensation means the total revenue received by a generator is rolled into a single value (rather than separate incentives from market revenues).

For this program, the electric distribution company (EDC) is responsible for paying the generator for their solar generation. One example of a total compensation incentive is the Solar Massachusetts Renewable Target (SMART) program that was launched in November 2018 and underwent its first 400 MW review in 2019. In this program, the total compensation is the sum of the base compensation rate for program participation and a compensation rate for optional adders and subtractors (e.g. installation location) that apply to a project.

The base compensation rate for total compensation incentive programs can vary based on several factors. For example, in the SMART program, the base compensation rate depends on EDC territory, capacity block, and generation unit capacity. This is described in more detail later. The SMART program also includes several innovative adders that increase incentive amounts for certain features, including energy storage, community solar and location-based incentives. These adders in a total compensation incentive enable policy makers to align incentive levels to solar projects' relative co-benefits.

Advantages

One of the key benefits of a total compensation incentive structure, as demonstrated by the SMART program, is certainty around the total value compensated to eligible projects. Within that total value the policy allows for the flexibility to incentivize and disincentivize project types through the establishment of various adders and subtractors that equate to different total compensation values. To encourage pairing of battery storage systems with solar PV systems, for instance, SMART provides adders that directly incentivize the installation of storage systems. Further, recent "emergency" changes to the program—the most significant of which was to double the available solar capacity from 1,600 MW to 3,200 MW—included a mandate for energy storage to be paired with solar projects greater than 500 kW.

The menu of adders and subtractors available to total compensation incentive programs are not limited to geographic placement of projects and battery storage. The SMART program has a range of innovative adders and subtractors including those to encourage a diversity of project types and steer development away from large-scale, ground mounted projects in undeveloped spaces. For this reason, the program contains greenfield subtractors to disincentivize ground-mount project development in previously undeveloped areas. Conversely, SMART offers adders that incentivize the development of projects on landfills, as parking lot canopies and in dual-use agriculture. The structure of a total compensation incentive program lends itself to the creation and modification of adders and subtractors to achieve more nuanced policy goals beyond the overarching policy goal of driving total capacity of solar PV installed.

Total compensation incentives provide price-certainty. Because the values are determined administratively, both EDCs and the generators know the value of solar generation. This helps both with planning for EDCs and in securing capital for generators.

Disadvantages

The adders and subtractors, and associated complex calculations, that enable total compensation incentive programs to have targeted policy impacts can also be a source of confusion. For example, in the SMART program, there are seven different levels of adders and subtractors based on the land use implications of the project. These range from subtractors for ground mounted solar projects to adders for projects that use space efficiently and provide co-benefits, including parking lot canopy projects. While these adders and subtractors may be well intentioned, they can also be ambiguous as to how project types are defined. Lack of clear definitions can lead to uncertainty regarding the overall financial viability of a project.

An example of this complexity having unintended consequences, at least as initially implemented in Massachusetts, was that larger, front-of-the-meter (FTM) projects largely squeezed out behind-the-meter (BTM) systems. As of September 2019, 60% of the large building mounted and canopy systems in the program were installed as standalone instead of BTM systems.[5] BTM systems provide several benefits, including more economic opportunities to pair with battery storage and reduce on-site demand; potentially reducing interconnection issues; and reducing interconnection costs and utility work associated with creating new standalone service. Although one aim of the SMART program was to incentivize BTM projects, the structure of the exported energy compensation initially reduced the financial viability of BTM projects and led to a flood of FTM project applications. Careful consideration

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[5] https://www.mass.gov/files/documents/2019/09/04/400%20MW%20Review%20DRAFT%20090419.pdf

must be paid to the design of total compensation incentive structures to ensure that BTM projects are adequately compensated and financially attractive to developers. Amending regulations to correct this flaw has been proposed as part of the 400MW review of the program.

Although not specifically related to the incentive type, an issue with SMART was the speed at which a number of service areas capacity caps were reached, in part due to the delay in the program's implementation and large projects holding space capacity in reserve (i.e., queue sitting). The certainty created by this incentive type can lead to many projects seeking to be constructed as early as possible when the policy is finalized.

Program Design Elements

The first design element to consider is *payment structure*. In the SMART program, after the application is approved by the program administrator and begins producing electricity, the tariff-based incentive is paid directly by the utility company to the system owner. While not unique to total compensation incentive programs, this type of program does lend itself to long-term tariffs that provide certainty of incentive level. For example, the SMART program offers fixed incentives paid to solar installers – 10-year terms for systems under 25 kW, and 20-year terms for systems over 25 kW.

It is also important to consider how the price will be set. Price *setting* for the base compensation rate in the SMART program is structured to provide higher levels of incentives to smaller projects per unit of energy generated, promoting a diversity of project types and sizes. The base level of incentive for the SMART program was determined by a competitive procurement for projects greater than 1 MW. This base level of incentive, or clearing price, is then used to set the incentive level for smaller projects pursuant to administratively determined multipliers. Arrays of 1 MW or more are eligible for 100% of the clearing price, while projects under 1 MW receive 110% to 230% of the clearing price depending on the project size.[6] Each utility in the SMART program has clear incentive blocks—up to eight blocks per EDC at the outset, recently expanded to 16 for some territories—with incentive levels that decline at prescribed rates between each block. This price setting structure creates clear guidance for developers on the incentive level they can expect and reduces financial uncertainty surrounding any given project.

Finally, the price *adjustment* mechanism for this type of incentive program is critical for ensuring that the program continues to effectively deliver on overall program goals. Given the relative complexity of a total compensation incentive program with multiple adders, subtractors, and pre-defined blocks that fill at varying rates, it is important to have regular, pre-defined formal program review periods. For example, the SMART program has a formal program review for every 400 MW increment of projects allocated, the first of which occurred in September 2019. This review period enables the regulatory body to review base compensation rates, compensation rate adders and subtractors, and overall cost impact to ratepayers to identify any potential necessary revisions to the program. Pre-established review periods allow policy to adapt to changing market conditions and efficiently allocate incentive funding.

[6] https://www.utilitydive.com/news/smart-start-massachusetts-utilities-solar-at-odds-over-proposed-incentive/437408/

These review periods also enable decision-makers to analyze other considerations that are often difficult to predict at the launch stage of a program. This includes assessing program access for low-income communities and geographic diversity.

Rhode Island Renewable Energy Growth Program

The Rhode Island Renewable Energy Growth (REG) REG program supports the development of distributed generation projects within the load zones of the EDC, National Grid, by enabling customers to sell their generation output under long-term tariffs at fixed prices. The REG program originally had a target of 160 MW of distributed renewable energy during its five-year term (beginning in 2015). It was later extended until the end of 2029 with a total cumulative procurement target of 400 MWs between 2020 and 2029. The tariff levels are set through a combination of competitive procurements and administratively determined prices. The EDC develops tariffs, which are then reviewed and approved by the Public Utility Commission. These tariffs are structured around 15- to 20-year term lengths and must include a ceiling price.

The program treats commercial scale projects differently than it does small-scale projects. For small-scale solar projects, which includes residential and small business projects up to 25 kW, the prices are based on the levelized cost of energy. The contracts are set up as a contract for difference for attributes, where the price is fixed on a dollar-per-kWh basis, less bill credits for energy and capacity used on site by the customer. For commercial scale projects, prices are set based on competitive procurements, with applicants submitting a bid price that cannot exceed the pre-determined price ceilings. The contracts are established as a fix dollar-per-kWh, which covers all energy, capacity, RECs, and other attributes.

Fixed Incentive

Fixed incentives offer set prices for environmental attributes and other value associated with production (kWh) from a solar array. The fixed incentive compensation is paid in addition to (i) any revenues the facility may earn, such as for sales of electricity, and (ii) any costs avoided through reduced energy consumption. For example, for a BTM project, the fixed incentive would be in addition to any avoided rate savings or net metering revenue. For a stand-alone FTM project, the fixed incentive would be in addition to the qualified facility or wholesale rates. This type of policy typically requires transmission and distribution utilities to purchase RECs from solar electricity generators at a fixed price through a long-term contract. The regulator usually establishes the price, although it can also be derived by a competitive market (see discussion of the CT ZREC program below). In addition to determining how the price will be set, the regulator can also set other design elements, such as contract terms and purchase and dispatch requirements. Fixed incentives can additionally interact with RPS policies, with utilities that purchase the RECs either using them to comply with their own RPS obligation or to sell them on a spot market.

Advantages

Fixed incentives’ long-term contract and fixed price for RECs provides solar developers a reliable and known revenue source over a long time period. This reduces risk for lenders, lessening the cost of obtaining capital for solar developers. Additionally, as such incentives are easy to understand, developers can more easily obtain needed capital from lenders, further reducing the cost of capital.

This incentive type's simplicity also reduces transaction costs by making it easier for developers to navigate a complicated regulatory environment, which offers the additional benefit of encouraging smaller projects to participate in the market. Fixed incentives also generally encourage more productive generating facilities as the incentive is tied to volume of electricity production rather than potential capacity. When considering these factors together, this incentive type creates rapid market growth and further drives down solar PV costs, reducing costs to ratepayers.

Disadvantages

The primary issue with this type of incentive program is the difficulty regulators face in administratively determining the appropriate price level. If the price level is set too high, the market will accelerate too quickly, solar developers will capture excess profit, and undesirable electricity rate increases may occur. Conversely, if the price level is set too low, the market will grow too slowly or not at all.

In response to striking an appropriate balance, regulators may need to hold frequent meetings to ensure prices are set at a suitable level, increasing the program's administrative and overall costs. Additionally, given this program type necessitates long-term contracts, the REC price is set for a long time period, hence lacking market-responsiveness. It is important to note, however, that program design can help mitigate some of these potential disadvantages.

Program Design Elements

The most common *payment structure* is direct payments to the generator as part of a multi-term contract. Alternatively, the payment can be given as a bill credit for the generator, through a net-metering program. This second approach is typically targeted at residential and small commercial and industrial (C&I) customers. Both methods are viable, with the latter providing a degree of simplicity for small customers.

Price setting in fixed incentive programs can utilize two primary methods. The regulator could set the price, or the price could be established based on a competitive bidding process. If the program utilizes the administrative model, the price could be established in several ways, including avoided cost or value-based (i.e. cost to society), among others. There are multiple methods that are valid and defensible; however, regulators need to ensure that they balance the need to spur investment with any potential adverse ratepayer impacts of an incentive-level that is too high.

The price could also be set in a competitive bidding process or by basing prices on a prior auction. A solicitation process is typically required for long-term PPAs or tariffs with transmission and distribution utilities, which are required to purchase RECs.

Fixed incentive programs can be differentiated into smaller subdivisions to reflect the unique challenges faced by projects of differing capacity levels. For example, competitive procurements are typically directed at larger installations, whereas smaller customers are often subject to fixed compensation programs that provide simplicity and lower transaction costs. However, if the state does not differentiate based on capacity level, installers can serve as aggregators for small customers, which better allows them to participate in competitive procurement processes.

Lastly, the regulator can implement *cost controls* to ensure the program maintains a reasonable scope and pricing level. Cost controls refer to constraints that are applied to the program. These can be in the form of program-wide constraints, such as limits to the total MW eligible for the program or limits on the total budget allocated to the program. Alternatively, the mechanisms can be applied at a smaller scale, with the regulator establishing a minimum and/or maximum price on RECs.

Connecticut ZRECs

Connecticut's Zero Emissions Renewable Energy Credit (ZREC) program started in 2012 and utilizes long-term contracts for RECs (i.e., not energy or capacity) to provide additional revenue for renewable generating facilities. The program covers Class I renewables and is split into three size-based categories: Small ZRECs (under 100 kW), Medium ZRECs (100-250 kW), and Large ZRECs (250-1,000 kW). EDCs purchase Medium and Large ZRECs in an auction, while the price for Small ZRECs is determined by adding a pre-determined premium to the weighted average of Medium auction prices. In 2012, the program required EDCs to purchase $8 million worth of 15-year contracts every year through 2018. The program has been extended twice and is currently set to run through 2021.

The CT ZREC program has an annual budget limit and a price cap on RECs (2019 cap: $126/REC), which help contain the costs of the program. The competitive-pricing aspect of the program also helps keep costs manageable for the regulated entities. However, the competitive bidding process can force project developers to bid below a financeable threshold in order to win, which can create a "race to the bottom." This can lead to a situation where projects associated with winning bids cannot realistically be completed due to lack of financing, causing overall instability in the market. Lastly, the program is based on a lottery system, so if a developer or customer does not win the lottery, they don't have access to the incentive.

New York NY-SUN C&I MW Block

The NY-Sun program offers financial incentives to install PV solar and is divided into three distinct regions across the state. By subdividing the state by region, the New York State Energy Research and Development Authority (NYSERDA) is better able to differentiate price based on the unique context in each region. Within each region, similar to the SMART program in Massachusetts, NYSERDA further subdivides the market into blocks and assigns an allocation of MWs that are eligible for NY-Sun incentives. These blocks correspond to residential, nonresidential, and large C&I industrial projects. Once the MWs are claimed within a region block, the incentives are no longer available. The price of the incentives within each region and block are administratively set based on historic demand, market potential, installed costs, and equity. The price of the incentive has decreased over time as market conditions make solar PV installations more economically viable. NYSERDA communicates the current price of the incentive and the remaining MWs available within each region block through an online dashboard. The program was initially approved in 2014 and was redesigned in 2018.

While the complexity of the program has created challenges in the past for those wishing to participate, the redesign created a more streamlined and transparent process. Additionally, because NYSERDA is responsible for setting the price and can provide a high degree of differentiation across the region blocks, the program can be nimble and responsive to changing market conditions. However, there is an added administrative burden and cost associated with the differentiated price-setting.

Illinois Adjustable Block Program

Enacted in 2007, the Illinois Power Agency Act required investor-owned electric utilities (IOUs) and retail suppliers to source 25% of electricity sales for renewable energy by 2025. The Act included various carve-outs, including a solar carve-out requirement that began in 2013 at 0.5% and ramped up to 6% by 2016. The Act also created the Illinois Power Agency (IPA), which was responsible for developing electricity procurement plans for IOUs.

Illinois' RPS was later revamped in 2017, with the enactment of the Future Energy Jobs Act. This act transitioned the state's RPS to a streamlined, centralized planning and procurement process, with both RPS targets and available budgets determined based on an electric utility's load for all retail customers. The funding is collected through a delivery services charge. As part of the Act, the IPA developed a Long-Term Renewable Resources Procurement Plan, the final version of which was released in April 2020. The plan outlines the implementation of the Adjustable Block Program along with additional solar incentive programs. The overall targets of the program include annual delivery of 2 million new PV RECs by mid-2021, 3 million by mid-2026, and 4 million by mid-2031. Of these targets, at least 50% need to be procured through the Adjustable Block Program, 40% through utility-scale projects (above 2 MW), and 2% from brownfield sites. The utility-scale and brownfield projects are priced based on competitive procurements.

Under the Adjustable Block program, IOUs purchase SRECs through 15-year fixed-price contracts. The initial price is administratively set by the IPA, with the price for each successive volumetric block being adjusted by the IPA based on the overall condition of the market. A portion of each volumetric block is reserved for certain project sizes, including 25 percent for small systems (less than 10 kW), 25 percent for large systems (between 10 kW and 2,000 kW), and 25 percent for community solar. While there is no cap on the program, the program has an initial goal of 1,000,000 RECs delivered annually by mid-2021, equating to roughly 666 MW of new solar generation.[7]

Market-Based RECs with Floor

Market-based RECs with a price floor necessarily requires the presence of an RPS. Regulated entities, which are typically electricity suppliers, meet compliance of an RPS by acquiring and retiring RECs that are generated through renewable energy production. Electric suppliers can attain RECs either directly from renewable energy producers, usually accompanied by a long-term contract, or through trading on spot markets.

While RECs generated from solar PV are generally eligible for RPS compliance, some states have chosen to create a specific carve-out for solar. Under this type of policy, a portion of the RPS compliance obligation needs to be met with solar renewable energy credits (SRECs), which are generated by solar

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7 http://illinoisabp.com/about-the-illinois-abp/

PV. This carveout means that SRECs trade at a different, typically higher, price than other RECs. The higher priced SRECs increase solar demand, which also increases investment in the technology. Creating a minimum price floor for SRECs is a key component for this type of policy, as it mitigates downside risk and may improve the ability to finance projects.

Advantages

Market-based RECs with a price floor generally create demand for renewable energy. The price floor creates a degree of revenue stability (as compared to market-based RECs without a price floor), which reduces uncertainty around revenue for solar developers. The reduced degree of uncertainty makes it easier for solar developers to attain financing and reduces the cost of capital, which in turn reduces the overall cost of solar development. Lowering solar development costs reduces the adverse cost impacts on ratepayers from increased solar PV deployment. The impact on ratepayers is further reduced because this type of incentive encourages competition among PV installations, favoring lower cost projects.

Disadvantages

While a price floor can provide some stability to the market for SRECs, there is still a fair degree of volatility that can occur. For example, if there is a shortage of SRECs, their prices will spike. Further, this type of incentive is subject to risks associated with regulatory changes. If the regulation governing the market for SRECs undergoes a shift, this could produce a significant impact on the price of SRECs. Investors are aware of this risk and may be hesitant to fund a project that is subject to it. Alternatively, investors include a risk premium on the terms of the investment, driving up the cost of capital and therefore the cost of solar development.

Setting an effective price floor is also difficult. It needs to be set at level that is sufficient to provide adequate revenue to attract lenders who will provide debt financing at a reasonable cost. Additionally, there needs to be a credit-worthy entity who will be responsible for buying the SRECs at the price floor, to provide investor certainty. However, the floor should not be set too high, otherwise solar developers will capture excess profits at the expense of ratepayers. This also precludes the ability to take advantage of cost declines in “cohorts” of projects.

Market-based SREC incentives may also be deemed complex to forecast for developers and investors, given the number of “levers” (e.g., carve-out, SREC qualification life, ACPs) that may be deployed or adjusted by policy-makers/administrators to mitigate extreme market swings or to address unwanted trends.

Program Design Elements

A key design choice for a “market-based RECs with floor” incentive is *whether the price floor will be soft or firm*. A firm price floor establishes a buyer of last resort, who commits to purchasing SRECs at a floor price. The buyer, often an electricity supplier, can then sell the SRECs at market prices on a spot market. The supplier recoups the difference in the two prices by incorporating it into the cost of electricity, placing the burden on ratepayers.

A soft price floor is subject to a dynamic supply with a responsive demand target. This reallocates risk from ratepayers to project owners. Soft floors offer a benefit by allocating risk in a way that allows ratepayers to benefit from the solar deployment's declining costs. A firm floor would keep SREC prices at a certain level, possibly providing excess profit to solar developers and placing the burden on ratepayers in the event of declining solar development costs. Conversely, a soft price floor allows the flexibility for lower prices.

Firm price floors have several advantages for decreasing capital costs by making solar investment more appealing for lenders. By utilizing a credit-worthy entity to guarantee purchase of RECs at a given price, a firm price floor essentially replicates a long-term contract, creating price certainty over the regulation's lifetime. This increased certainty attracts more lenders to the market, making capital less costly and more accessible. Further, a firm price floor is far easier to explain to investors than a soft price floor, reducing the contextual knowledge that a lender would need to enter the market. The increased number of lenders participating in the market increases competition and further drives down the cost of attaining capital for solar investors.

Another mechanism, often paired with market-based RECs, is a requirement for *long-term contracts or tariffs*. These long-term contracts could be structured to include the RECS, energy, and capacity, or just the unbundled RECs. Long-term contracts create more certainty in the market, but they are not responsive to changing market dynamics due to their long-term nature. Additionally, long-term contracts that are established through a competitive bidding process, which can pose a barrier for smaller-scale projects' entry to the market as smaller project developers generally do not have the sufficient knowledge and resources to compete with larger operations.

Some states implement *SREC factors* in program design. These factors discount the value of SRECs for certain types of solar development, thus incentivizing certain types of solar development over others. For more information, see the MA SREC I and II discussion that follows. While this mechanism can encourage development in desired areas (e.g., community solar generation), it increases the program's complexity.

Massachusetts SREC I and II

Massachusetts has utilized a soft price floor for both its SREC I and SREC II programs. In both programs, Massachusetts used a unique supply-responsive demand formula that changed targets annually, based on historical data regarding the volume of installed solar, alternative compliance pathway (ACP) payments, and other market trends. The price floor was created by allowing unsold SRECs to be placed in a state-sponsored, fixed-price auction at a set price.

If RECs were not all sold in the first round of the auctions, then additional auction rounds extended the life of the purchased SRECs. This is a considered a soft price floor because SRECs were still sometimes sold below the price floor, which occurs if sellers expect the market price to fall below the price floor in the future. Sellers will choose to sell below the price floor because, with the time value of money, it may be advantageous to sell SRECs sooner than later. Under the second phase of the SREC program (SREC II), Massachusetts incorporated a SREC factor, which incentivizes solar development within specific market sub-sectors (e.g. low- or moderate-income housing generation units, generating units cited on brownfields). These programs have proven effective in creating a robust solar PV market in Massachusetts.

4. Successor Program Modeling Overview

Cadmus analyzed the Successor Program using two main models:

- **Project Model:** Multiple, representative project types (cases) were modeled using solar-specific modeling software, the System Advisor Model (SAM). Each case captured different ownership, customer, size, and/or installation types for projects in the market. The model employs a range of inputs for costs, energy production, and revenue streams, some of which change each year over the modeling period (2020 through 2030). Each case runs through a simulation that solves for an incentive that allows the representative project to achieve a desired economic target. A separate Microsoft Excel model sets up inputs for the modeling software.
- **Market Model**: Cadmus created a separate Excel model that forecasts market-level solar installations, allocates solar-installed capacity among the three major solar programs (the Legacy SREC Program, the Transition Incentive Program, and the Successor Program), estimates aggregate production, and derives estimated program costs based on the required incentives generated by the project-level modeling. In addition to solar, the Market Model forecasts other Class I REC programs and performs tests to determine adherence to the Cost Cap.

These models are discussed below.

> ***Modeling Note****: Cadmus chose modeling components and built model structures to be as transparent and usable as was feasible. Where possible, we have used data and methods that should (i) make modeling repeatable as updates are available; and (ii) be flexible enough to adjust as needed. Cadmus welcomes additional stakeholder feedback on modeling inputs, methodology, and structure.*

> ***Modeling Note****: Calculations and inputs reflect conditions prior to the onset of the COVID-19 pandemic. Given the uncertainty caused by the outbreak, stakeholders should take care applying historical-based data to current market conditions or extrapolating current market conditions to more steady-state.*

4.1. Project Model

Cadmus utilized SAM for modeling project-level energy production and economics. SAM is an open-source, techno-economic software model, developed by the National Renewable Energy Laboratory (NREL) to estimate the performance and cost of renewable energy systems, including solar. A complementary Excel file stores and, as needed, calculates base inputs for the SAM modeling.[8]

8 More information about SAM is available on the NREL website: https://sam.nrel.gov/

High-Level Modeling Choices

SAM provides flexibility in choosing modeling methods, inputs, and outputs. The first high-level decisions involve project performance and financial modeling, as discussed below.

Performance Modeling

To estimate energy production, SAM provides a choice between implementation of PVWatts, another NREL tool widely used in the solar industry (including by NJCEP), or of a more-detailed method based on specific equipment. Given that projects modeled herein are meant to be representative but hypothetical, and therefore need not be detailed, Cadmus chose to deploy the PVWatts model.[9]

Financial Modeling

SAM provides a variety of different financial models to accommodate different ownership and value sources. For simplicity, Cadmus utilizes two of them, shown in Table 8. The table notes (i) how the project derives the primary value from the electricity generated by the PV system; and (ii) the economic target in SAM.

Table 8. SAM Financial Models

SAM Financial Model	Project Value Profile	Modeling Economic Target
Residential/Commercial Owner (Direct Ownership, or DO)	Achieve value through energy savings, based only on energy- (kWh-) based charges	Solve for Payback Year
PPA – Single-Owner	One entity owns the project and receives PPA revenue	PPA price is set as a discount to utility tariff rates for BTM projects or to reflect wholesale prices for Grid Supply projects. Solve for IRR[a]

[a] Internal rate of return.

> ***Modeling Note****: NREL has recently added to the list of financial models a Merchant Plant option, which may provide a reasonable option for modeling Grid Supply projects. Given the time constraints for the analysis of this draft report, Cadmus utilized the PPA financial model for Grid Supply projects.*

SAM Case Derivations

The Project Model uses those two types of SAM financial models above to run simulations on project variants, called "SAM Cases." These SAM Cases are meant to be representative projects of the solar fleet that capture different cost or design profiles, for instance:

- Installations on pitched rooftops have orientations (tilt and azimuth) that are generally governed by the planes of the roof.

[9] Of note, SAM's latest version states that it uses PVWatts Version 7, which is a more recent version than the online PVWatts calculator.

- Carports are (i) generally constrained to the azimuth of the "spine" of parking spaces in the parking lot; (ii) typically have relatively low tilts due to structural and associated cost considerations; and (iii) have additional costs that differ from other projects, such as additional steel for support structures.
- Ground-mount systems allow for relatively optimal orientation, but they may pose costs (e.g., grading, tree removal) not generally required for the "built" environments of rooftops and parking lots.
- Community Solar projects have certain unique, upfront costs (e.g., acquiring subscribers, setting up utility bill allocations) and ongoing administrative costs (e.g., allocation of credits and managing potential subscriber churn).
- Smaller projects tend to have higher costs on a normalized basis (i.e., dollars per nameplate capacity, $/W) than larger projects, which, for instance, can spread certain fixed costs over a larger capacity.

Of note, all references to solar capacity are in direct current (DC), unless otherwise indicated.

SAM Cases Based on Historical and Pipeline Project Lists

Certain inputs for the initial set of SAM Cases were derived by analyzing installed and pipeline project data in NJCEP's *Solar Equipment List* as of March 31, 2020 (March 2020 Equipment List).[10] Data fields in the list used to establish SAM Cases included the following:

- **Customer Type** differentiates between residential (Resi) and commercial (Comm) customers
- **Third Party Ownership** distinguishes between direct ownership (DO) and third-party ownership (TPO)
- **Grid/Behind the Meter** identifies Grid Supply projects vs. BTM (net metered) projects
- **Equipment Name** was filtered to include only "Solar Panels" so that other fields can be used to garner information—see below
- **Rating per Module** provides one component of the record-level capacity calculation
- **Module Quantity** provides the other component of the record-level capacity calculation
- **Location of Equipment** identifies installation type (ground, roof, or carport)

In order to assess relatively new projects, Cadmus filtered the data set to include only pipeline projects and projects with dates of permission to operate (PTO) from the utility in 2019 or 2020—PTO is used here as an approximation for commercial operation.

Cadmus performed several steps to assess data quality and to conform the data as desired:

- Excluded records with Equipment Name other than "Solar Panels."

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10 Solar activity reports, including lists of installed and pipeline projects and equipment, are available on NJCEP's website: https://www.njcleanenergy.com/renewable-energy/project-activity-reports/project-activity-reports.

- Fixed some input errors for module ratings (e.g., to match clearly incorrect entries of module-level capacity, based on the module model).
- Compared the aggregate, record-level capacity with the project's stated capacity. Cadmus found (i) several duplicate/quadruplicate sets of records, from which only one record was kept; and (ii) additional instances where the capacities differed (on an absolute basis) by more than 0.6 kW that were excluded.
- Populated SAM Cases using the fields discussed above.

Of note, several projects had more than one SAM Case (e.g., both rooftop and ground-mount arrays). Cadmus used these equipment-level records for certain analyses, such as for array orientation, but excluded them for other assessments, such as deriving project installed costs.

Table 9 shows the initial grouping of SAM Cases. Note: this listing includes neither (i) Community Solar, which is a new type of project, nor (ii) an out-of-state variant, requested by the BPU. Incorporation of these cases follows.

Table 9. Derivation of SAM Cases – Initial Groupings

Major Category	Ownership	Installation Type	Preliminary SAM Case	Capacity (kW)	% Total	% Major Category
Commercial	Direct (Host)	Carport	Comm_DO_Carport	13,415	1.5%	3.1%
Commercial	Direct (Host)	Ground	Comm_DO_Ground	24,343	2.7%	5.6%
Commercial	Direct (Host)	Roof	Comm_DO_Roof	172,464	18.9%	39.5%
Commercial	Third Party	Carport	Comm_TPO_Carport	40,050	4.4%	9.2%
Commercial	Third Party	Ground	Comm_TPO_Ground	87,335	9.6%	20.0%
Commercial	Third Party	Roof	Comm_TPO_Roof	99,076	10.9%	22.7%
Grid	Third Party	Ground	Grid_Ground	191,306	21.0%	91.6%
Grid	Third Party	Roof	Grid_Roof	17,624	1.9%	8.4%
Residential	Direct (Host)	Ground	Resi_DO_Ground	5,077	0.6%	1.9%
Residential	Direct (Host)	Roof	Resi_DO_Roof	105,542	11.6%	39.5%
Residential	Third Party	Ground	Resi_TPO_Ground	2,259	0.2%	0.8%
Residential	Third Party	Roof	Resi_TPO_Roof	154,328	16.9%	57.8%
Total				**912,820**		
Aggregated Capacity (kW) by Major Category						
Commercial				436,683		
Grid				208,930		
Residential				267,207		
Total				**912,820**		

Notes:
Based on analysis of March 2020 equipment lists for installed projects (PTO in 2019-2020) and pipeline projects.

As a means of streamlining modeling, Cadmus evaluated each SAM Case's share of the assessed portfolio capacity and that of the respective major category—commercial, grid, and residential. Based on relatively small shares, Cadmus excluded Comm_DO_Carport, Resi_DO_Ground, and Resi_TPO_Ground. While only a few Grid_Roof projects emerged, Cadmus included that case as a strong future prospect. The adjusted list, shown in Table 10, includes the recalculated percentage shares of capacity.

Table 10. Derivation of SAM Cases – Reduced Grouping

Preliminary SAM Case	Ownership	Installation Type	Capacity (kW)	% Total
Comm_DO_Ground	Direct (Host)	Ground	24,343	2.7%
Comm_DO_Roof	Direct (Host)	Roof	172,464	19.3%
Comm_TPO_Carport	Third Party	Carport	40,050	4.5%
Comm_TPO_Ground	Third Party	Ground	87,335	9.8%
Comm_TPO_Roof	Third Party	Roof	99,076	11.1%
Grid_Ground	Third Party	Ground	191,306	21.4%
Grid_Roof	Third Party	Roof	17,624	2.0%
Resi_DO_Roof	Direct (Host)	Roof	105,542	11.8%
Resi_TPO_Roof	Third Party	Roof	154,328	17.3%
Total			**892,068**	

Notes:
Based on analysis of March 2020 equipment lists for installed projects (PTO in 2019-2020) and pipeline projects.

New SAM Case: Community Solar

Cadmus established Community Solar SAM Cases based on discussions with BPU Staff and on a review of BPU's Order *In the Matter of the Community Solar Energy Pilot Program,* dated December 20, 2019, and amended February 5, 2020 (collectively, the CS Order). A summary of conditionally approved projects for Program Year 1 of the Pilot Program are shown in Table 11 below. Given the similar shares of ground mount and rooftop systems, Cadmus established Preliminary SAM Cases for Community Solar ground (CS_Ground) and roof (CS_Roof) installation types. The carport variant was not modeled due to small market share.

Table 11. Community Solar Projects by Installation Type

Installation Type	Total Capacity (kW)	% Total	Avg. Capacity (kW)
Ground [1]	38,029	49%	3,457
Roof [2]	36,756	47%	1,149
Carport [2]	3,200	4%	1,067
Total	**77,985**		

Notes:
Source: BPU Order on the Community Solar Energy Pilot Program, December 20, 2019 (as amended February 25, 2020).
1. Comprised mostly (87%) of landfill projects.
2. One project indicated mixed rooftop and parking lot. Cadmus split capacity 50/50 between the two installation types.

Of note, the model assumes that Community Solar will be additive to the solar fleet. In practice, however, this new project type may offset other projects (i.e., similar larger-scale installations) as well as residential and/or commercial individual systems, where prospective hosts choose the subscription model instead of owning the solar system or entering into an agreement with a third-party owner.

New SAM Case: Out-of-State Grid Supply

Cadmus also included an out-of-state (OOS) SAM Case variant. Cadmus assumed the project would be a large, ground-mount system located in the PJM territory. In some instances, Cadmus adopted input assumptions for similar SAM Cases in New Jersey, whereas, for other inputs, Cadmus evaluated separate data. The separate input sections below discuss choices for this OOS variant.

> ***Modeling Note**: Cadmus includes inputs for the out-of-state variant only for illustrative purposes. Further, Cadmus welcomes feedback from stakeholders on potential projects outside of New Jersey that might be appropriate for the market.*

SAM Case Tiering and Final SAM Cases List

The final phase of SAM Case derivations emerged from analysis of installed cost ($/W) data provided by the BPU, discussed in more detail in the Capital Expenditures section. Material differences in installed costs for different sizes of certain SAM Cases derived above suggested they should be modeled separately. Table 12 shows the final list of 19 SAM Cases that Cadmus modeled.

Table 12. SAM Case Descriptions

Final SAM Case	Major Category	Ownership	Installation Type	Capacity Tier if Applicable
SAM Cases Based on Historical Data				
Comm_DO_Ground_lg	Commercial	Direct (Host)	Ground	1 MW and greater
Comm_DO_Ground_med	Commercial	Direct (Host)	Ground	100 kW up to 1 MW
Comm_DO_Roof_lg	Commercial	Direct (Host)	Roof	1 MW and greater
Comm_DO_Roof_med	Commercial	Direct (Host)	Roof	100 kW up to 1 MW
Comm_DO_Roof_sm	Commercial	Direct (Host)	Roof	up to 100 kW
Comm_TPO_Carport	Commercial	Third Party	Carport	
Comm_TPO_Ground_lg	Commercial	Third Party	Ground	1 MW and greater
Comm_TPO_Ground_med	Commercial	Third Party	Ground	100 kW up to 1 MW
Comm_TPO_Roof_lg	Commercial	Third Party	Roof	1 MW and greater
Comm_TPO_Roof_med	Commercial	Third Party	Roof	100 kW up to 1 MW
Comm_TPO_Roof_sm	Commercial	Third Party	Roof	up to 100 kW
Grid_Ground	Grid	Third Party	Ground	
Resi_DO_Roof	Residential	Direct (Host)	Roof	
Resi_TPO_Roof	Residential	Third Party	Roof	
New SAM Cases				
Grid_Ground_OOS	Grid	Third Party	Ground	
Grid_Roof	Grid	Third Party	Roof	
CS_Ground	Community Solar	Third Party	Ground	
CS_Roof_lg	Community Solar	Third Party	Roof	1 MW and greater
CS_Roof_med	Community Solar	Third Party	Roof	100 kW up to 1 MW

Notes:
Based on analysis of (i) March 2020 equipment lists for installed projects (PTO in 2019-2020) and pipeline projects; (ii) conditionally approved Community Solar projects for Program Year 1 of that pilot program; and (iii) additional data for the out-of-state variant as discussed above.

Importantly, the above breakdown reflects largely recent, historical trends. Cadmus used this for draft modeling purposes and recommends against using it as a prescriptive list for incentive categories, such as for the following reasons:

- The low market share of a SAM Case (indicated above) may reflect a market impediment, which, if mitigated, could allow that segment to become more competitive.
- Emerging or potential new segments, such as floating solar, building-integrated PV, and solar co-located with agriculture production (dual-use) could provide various benefits and opportunities for growth, but may pose unique cost profiles and design variations and/or may require updates to policy, legislation, and regulation to grow. Such variants may be modeled separately.

SAM Model Inputs

The following sections discuss key inputs and methodology used in SAM; they are generally ordered by broad SAM sections:

- Location and Resource
- System Design
- System Costs
- Financial Parameters
- Revenue/Electricity Rates
- Incentives

Location and Resource

Cadmus based the solar resource on weather files available in SAM from various locations. For New Jersey-based projects, Cadmus used the “New Jersey” weather files for Station ID 1223508, located southeast of Trenton. This file provides a TMY (typical meteorological year) of weather estimated from 1998 to 2018. For the out-of-state variant, Cadmus used the TMY file from Richmond, Virginia, for Station ID 1132891.

System Design

System Parameters

System parameters include the following inputs:

- **Nameplate** (Capacity in kW DC): Cadmus determined representative capacities, as discussed below.
- **DC-to-AC ratio** (a.k.a. inverter load ratio (ILR): Cadmus assumed a ratio of 1.2x.
- **Inverter efficiency**: Cadmus chose 97.1%, the average for installed projects in the years 2016–2018.

For the Nameplate input, Cadmus chose capacities based on median and average capacities, calculated for each SAM Case, as shown in Table 13. SAM Cases for small, commercial ground-mount projects as well as for a small Community Solar rooftop project, were not modeled due to their small market share.

For the out-of-state variant, Cadmus reviewed projects registered with PJM GATS,[11] adjusting the data as follows:

- Kept only projects where Primary Fuel Type was "SUN"
- Excluded projects with Nameplate < 5 MW (in AC)
- Kept only projects with PJM Interconnection as Balancing Authority

[11] Source PJM website: https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS.

- Excluded projects online before 2018

Reviewing sizes by state, a capacity of 10 MW (DC) for a prototypical out-of-state project was chosen, as it comprises a large share of projects in PJM's territory and sufficiently larger than other SAM Case projects modeled.

The Community Solar modeled capacities, shown in the SAM Case derivation section, were based on the project's average size.

Table 13. Modeled Capacity

	Capacity (kW)		
SAM Case	Median (50th Percentile)	Average	Modeled Project Capacity
Historical SAM Cases [1]			
Comm_DO_Ground_lg	3,448	3,316	3,500
Comm_DO_Ground_med	441	494	500
Comm_DO_Roof_lg	1,750	2,440	2,000
Comm_DO_Roof_med	261	355	350
Comm_DO_Roof_sm	31	37	35
Comm_TPO_Carport	624	1,679	1,500
Comm_TPO_Ground_lg	1,936	3,866	3,500
Comm_TPO_Ground_med	382	460	450
Comm_TPO_Roof_lg	1,971	2,281	2,000
Comm_TPO_Roof_med	121	257	250
Comm_TPO_Roof_sm	27	36	35
Grid_Ground	4,799	9,104	7,000
Resi_DO_Roof	9	10	8
Resi_TPO_Roof	8	8	8
New SAM Cases			
CS_Ground [2]	3,150	3,457	3,500
CS_Roof_lg [2]	1,907	2,061	2,000
CS_Roof_med [2]	640	628	650
Grid_Ground_OOS [3]	n/a	n/a	10,000
Grid_Roof [4]	n/a	n/a	2,000

Notes:
1. Based on an analysis of the March 2020 equipment and cost lists.
2. Based on an analysis of conditionally approved project data from BPU Order on the Community Solar Energy Pilot Program, December 20, 2019 (as amended February 25, 2020).
3. Based on analysis of solar projects registered in PJM GATS.
4. Since there were only three records for Grid_Roof (all from the pipeline), Cadmus adopted modeled capacity from the large commercial roof SAM Case (Comm_TPO_Roof_lg).

***Modeling Note**: Residential system capacity modeled has been based on a review of historical trends. As noted in the Focus Group review (Section 2.4), changes to setback requirements may impact system size. Further analysis and stakeholder feedback may be warranted.*

Orientation

Cadmus used the *March 2020 Equipment List* to derive tilt and azimuth (collectively termed "orientation" here), following similar steps as with the SAM Case derivation discussed above.

As a means of streamlining overall modeling, Cadmus used a pared-down list of project types, in lieu of the entire SAM Case list, under the assumption that most variants would be similar; earlier work corroborated that notion. Table 14 shows the results. As part of the data set preparation, Cadmus followed these steps:

- Started with lists previously reviewed/adjusted in the SAM Case derivation and Capex analysis but added back records with more than one installation type.
- Created broad project types that did not differentiate by ownership.
- Excluded pole-mounted and tracker projects.
- For tilt:
  - Excluded those project entries with a tilt greater than 60° and between 0° and 1°
  - Aggregated capacity for each project type for remaining records
  - Calculated straight average tilt, capacity-weighted average tilt, and standard deviation by project type, as shown in Table 14
- For azimuth:
  - Excluded values less than 90° and greater than 270° as well as several entries that did not otherwise conform to the data type (e.g., just a word, like "South", although several with words specific enough were converted to degrees.
  - To assess the deviation of projects' azimuths from Due South (180°), Cadmus converted all arrays pointing southeast to the equivalent deviation southwest; for instance if the project azimuth were 160° (20° off Due South to the east), it was converted to 200° (20° off Due South to the west).
  - Aggregated capacity for each project type for remaining records.
  - Calculated straight average azimuth, capacity-weighted average azimuth, and standard deviation by project type (shown in Table 14).

Table 14. Modeled Orientation by Broad Project Type

	Tilt				Azimuth [3]			
Broad Project Type [1]	Weighted Average [2]	Average	Standard Deviation	Tilt Modeled	Weighted Average [2]	Average	Standard Deviation	Azimuth Modeled
Commercial Carport	7°	6°	4°	7°	217°	218°	25°	215°
Commercial Ground	16°	23°	17°	18°	197°	191°	17°	195°
Commercial Roof	9°	15°	14°	12°	207°	213°	24°	200°
Grid Ground	18°	19°	6°	18°	180°	182°	5°	180°
Grid Roof [4]	10°	10°	n/a	10°	207°	213°	24°	200°
Residential Roof	26°	27°	15°	26°	221°	222°	26°	220°

Notes:
Based on an analysis of March 2020 installed and pipeline equipment lists. Exclusions for data entry errors as previously discussed.
1. Differentiates only (i) by customer/grid and installation type and (ii) only to cover SAM Cases modeled.
2. Weighted by record-level capacity within each Broad Project Type.
3. Counted only where azimuth was between 90° and 270°; then converted all southeast (90° up to 180°) to equivalent southwest (180° to 270°).
4. Uses azimuth values for commercial roof.

Another design choice is the array racking type. Cadmus used "Fixed roof mount" for residential, since those modules are typically installed in the same plane (tilt) as the roof. For all others, Cadmus used "Fixed open rack," as (i) ground mount is generally open racking; and (ii) commercial installations are assumed to be on flat roofs and tilted via the racking.

System Losses and Energy Production Estimates

As an initial step to estimate system losses, Cadmus followed the instructions in NJCEP's NREL PVWatts Calculator presentation, *Introduction to the PVWatts Calculator*. All losses were left at default values, except as follows:

- Inverter Efficiency: 97.1%, consistent with widely used inverters in the NJ solar project portfolio
- Module Mismatch: 0%, consistent with datasheets of widely used modules in the NJ solar project portfolio
- PV Module Nameplate Rating: 0%, consistent with datasheets of widely used modules in the NJ solar project portfolio
- Shading: Cadmus performed an analysis of shading percentages for similar types of solar projects[12]

Cadmus generated energy estimates in SAM, based on the system design inputs discussed above. To streamline modeling, Cadmus used the set of Broad Project Types, discussed in the Orientation section.

A common metric for normalizing solar energy production is specific energy production (SEP), which measures energy per capacity in either MWh/MW or kWh/kW. A related measure is capacity factor,

12 Sources: *Vermont Solar Cost Study*, CleanEnergy States Alliance, February 2016; and a review of Massachusetts Production Tracking System data, which Cadmus serves as an advisor.

which measures the percentage of energy produced in a period, compared to the generator's potential, based on nameplate capacity.

Table 15 shows the SEPs for Year 1, resulting from the steps above. For the remaining years of a project's life, Cadmus assumed an annual AC degradation rate of 0.5%.

Table 15. Year 1 SEPs and Capacity Factors by Broad Project Type

														Capacity	Seasonal Weights [1]	
Broad Project Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year 1	Factor	Summer	Winter
Commercial Carport	65	86	119	141	143	152	154	134	117	98	72	55	1,336	15.2%	42%	58%
Commercial Ground	80	100	129	144	140	147	151	136	124	111	88	70	1,419	16.2%	39%	61%
Commercial Roof	73	92	124	142	141	149	153	135	120	104	80	62	1,376	15.7%	40%	60%
Grid Ground	81	101	130	144	139	148	151	136	125	112	90	71	1,428	16.3%	39%	61%
Grid Ground (OOS)	87	100	120	141	148	146	147	148	126	115	88	76	1,442	16.5%	39%	61%
Grid Roof	69	89	120	140	139	148	151	133	117	100	76	59	1,340	15.3%	41%	59%
Residential Roof	73	90	113	126	123	126	132	118	107	98	78	64	1,247	14.2%	39%	61%

Notes:
All in kW/kWh, except Capacity Factor and Seasonal Weightings
1. Based on utility seasons: Summer is June through September, Winter is October through May. Given the similarity among the results, Cadmus used a 40%/60% allocation for Summer/Winter in the Successor Program Model.

System Costs

Capital Expenditures

Cadmus analyzed installed cost data, provided by BPU for the same set of projects in the *March 2020 Equipment List,* analyzed in the derivation SAM Cases. A summary of steps follows:

- At the outset, Cadmus excluded zero costs or installed costs exceeding $10/W.
- Cadmus determined that groups of projects fell under "portfolios" (i.e., multiple projects were assigned the same cost); so that per-project cost was not representative of installed cost per project type. From this analysis, Cadmus excluded all projects within readily apparent portfolios.
- To assess outliers more specific to project types, Cadmus generated histograms of installed costs for each SAM Case (see examples provided in Appendix A). Through that visualization, Cadmus chose minimum and maximum values, based on very low and/or very high perceived outliers (shown in Table 16, outside of data ranges excluded).

Table 16. Installed Cost Outlier Ranges

	Data to Exclude	
SAM Case	Below $/W	Above $/W
Comm_DO_Ground	$ -	$ 4.50
Comm_DO_Roof	$ 0.70	$ 4.50
Comm_TPO_Carport	$ 2.00	$ 4.00
Comm_TPO_Ground	$ 1.00	$ 4.50
Comm_TPO_Roof	$ 1.25	$ 4.00
Grid_Ground	$ 1.00	$ 3.50
Grid_Roof	$ -	$ 10.00
Resi_DO_Roof	$ 2.00	$ 6.00
Resi_TPO_Roof	$ 2.00	$ 5.00

Notes:
Based on analysis of equipment lists for installed projects (PTO in 2019-2020) and pipeline.

- After filtering out records outside those ranges, Cadmus reviewed several breakdowns of SAM Cases by size categories. Typically, we evaluated one or two capacity "breakpoints," where average installed costs were calculated for data below and above those thresholds. Cadmus primarily viewed scatterplot graphs and calculated 50th and 70th percentiles to compare installed costs for different sizes of SAM Cases. As part of the review, Cadmus assessed the same breakpoints used in the NJCEP solar project reports: 100 kW and 1 MW. Cadmus found significant cost differences around those breakpoints so decided to split most commercial SAM Cases into those three tiers, as shown in Table 13.

For the out-of-state SAM Case, Cadmus reviewed several sources, including the following:

- The latest (2019) edition of Lawrence Berkeley's utility-scale solar trends report.[13] Cadmus reviewed median installed costs and converted from AC- to DC-based, using the report's capacity-weighted ILR) for the Southeast and Northeast regions. The resulting cost was approximately $1.13/W.
- Solar project data, maintained by New York's NYSERDA office.[14] Cadmus excluded projects with nameplate capacity less than 5 MW and with application dates prior to 2019. We then reviewed a histogram of remaining projects and decided to exclude outlying costs less than $0.80/W and greater than $1.80/W. The resulting average cost was approximately $1.20/W.

Installed costs for Community Solar projects were derived using comparable commercial TPO projects and adding a $0.20/W premium to reflect additional subscriber and administrative set-up costs.

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13 *Utility-Scale Solar Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States –2019 Edition.* Lawrence Berkeley National Laboratory. December 2019.

14 Solar Electric Programs Reported by NYSERDA from NYS website. Accessed June 15, 2020. Available at: https://data.ny.gov/Energy-Environment/Solar-Electric-Programs-Reported-by-NYSERDA-Beginn/3x8r-34rs.

***Modeling Notes**: Cadmus has requested cost data from the BPU for Community Solar projects, as these may provide a greater understanding of additional costs borne by those projects. In addition, future discussions with stakeholders could focus on differentiated costs for projects installed on landfills, brownfields, or other ground types.*

Table 17 shows the resulting modeled, installed costs following these analyses.

Table 17. Installed Costs by SAM Case

	Installed Cost ($/W)			
SAM Case	Straight Average	Weighted Average	Median (50th Percentile)	Modeled Cost ($/W)
Historical SAM Cases [1]				
Comm_DO_Ground_lg	$ 1.89	$ 1.94	$ 1.88	$ 1.90
Comm_DO_Ground_med	$ 2.52	$ 2.37	$ 2.40	$ 2.40
Comm_DO_Roof_lg	$ 1.76	$ 1.70	$ 1.69	$ 1.70
Comm_DO_Roof_med	$ 2.13	$ 2.06	$ 1.98	$ 2.10
Comm_DO_Roof_sm	$ 2.67	$ 2.57	$ 2.59	$ 2.60
Comm_TPO_Carport	$ 2.69	$ 2.69	$ 2.65	$ 2.65
Comm_TPO_Ground_lg	$ 2.03	$ 1.83	$ 1.89	$ 1.85
Comm_TPO_Ground_med	$ 2.24	$ 2.35	$ 2.30	$ 2.30
Comm_TPO_Roof_lg	$ 1.75	$ 1.59	$ 1.75	$ 1.65
Comm_TPO_Roof_med	$ 2.09	$ 2.04	$ 2.22	$ 2.05
Comm_TPO_Roof_sm	$ 2.60	$ 2.48	$ 2.63	$ 2.55
Grid_Ground	$ 1.96	$ 1.88	$ 1.91	$ 1.90
Resi_DO_Roof	$ 3.56	$ 3.49	$ 3.52	$ 3.45
Resi_TPO_Roof	$ 3.48	$ 3.43	$ 3.51	$ 3.45
New SAM Cases				
CS_Ground [2][3]	n/a	n/a	n/a	$ 2.05
CS_Roof_lg [2][3]	n/a	n/a	n/a	$ 1.85
CS_Roof_med [2][3]	n/a	n/a	n/a	$ 2.25
Grid_Ground_OOS [4]	n/a	n/a	n/a	$ 1.15
Grid_Roof [5]	n/a	n/a	n/a	$ 1.65

Notes:

1. Based on an analysis of the March 2020 equipment and cost lists.
2. Based on an analysis of conditionally approved project data from BPU Order on the Community Solar Energy Pilot Program, December 20, 2019 (as amended February 25, 2020).
3. Modeled Costs based on comparable commercial TPO projects plus an adder of $0.20/W to reflect subscriber setup, utility interacction, and other setup tasks unique to these projects.
4. Based on analysis of other utility projects in the region.
5. Since there were only a few records for Grid_Roof, Cadmus adopted modeled cost from the large commercial roof SAM Case (Comm_TPO_Roof_lg).

Cadmus broke out major equipment—modules and inverters—to track those costs separately. Based on a review of several sources, Cadmus used the assumed base commercial module and inverter costs of \$0.30/W and \$0.10/W, respectively, with \$0.05/W adjustments up/down for residential/large projects.[15]

The model assumes inverter replacement at Year 13 at a cost adjusted over the period, based on the growth rate discussed below. Decommissioning costs of \$0.02/W were included in the final (25th) year of the project's life.

> ***Modeling Note****: The DO and PPA financial models in SAM have some different provisions for financing. The PPA model, for instance, provides for major equipment reserve accounts (MERAs), which Cadmus used for the inverter replacement and decommissioning costs. The DO model does not provide for MERAs, so Cadmus included those costs as part of operating expenditures in the respective years. Based on a comparison of the PPA financial model using both methods, the impact was relatively small.*

Operating Costs

Assumptions for operating expenditures (Opex) were adopted largely from the Transition Incentive modeling work, summarized as follows (and in Table 18):[16]

- **Project Management Costs**: Adopted from Transition Incentive modeling and based on similar project types/sizes: \$17 per year for project capacity less than 25 kW; \$1,625 for 250 kW; \$3,000 for 250 kW to 1 MW; \$5,000 for 1–5 MW; and \$6,337 for greater than 5 MW.
- **Property Taxes/Payment in Lieu of Taxes** (**PILOT**): Per New Jersey law, solar equipment—added to a residential, commercial, industrial, or mixed-use building, and providing all or a portion of a building's electrical needs—remains exempt from property tax.[17] Cadmus assumes that all residential and commercial projects, regardless of installation types, are built to offset on-site loads, thus becoming eligible for the property tax exemption. Grid Supply and ground-mount Community Solar projects, however, are assumed installed on standalone parcels without on-site load. Presumably, those projects would not be eligible for the exemption. Cadmus adopted the Transition Incentive modeling rate of \$5,000 per MW per year, modeled for projects 5 MW or larger (CS_Ground, modeled as slightly smaller, was also included).
- **Site Lease Payments** were included for TPO commercial systems, Community Solar, and Grid projects. Transition Incentive modeling annual cost assumptions were adopted:

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15 In particular, Cadmus relied for module pricing from the *U.S. Solar Market Insight Executive Summary.* Wood Mackenzie and Solar Energy Industries Association. June 2020. Base commercial pricing is a blend between U.S. multimodule and mono PERC prices.

16 Primary source for TI modeling Opex assumptions was *Attachment 1: Pipeline Supply Model Inputs and Assumptions, New Jersey Transition Incentive Supporting Analysis and Recommendations – August 2019*.

17 Reference: New Jersey Statutes §54:4-3.113(a-b) found at website: https://lis.njleg.state.nj.us/.

- $0 for projects less than 60 kW (increased Transition Incentive modeling breakpoint from 25 kW)
- $10,000 for 60-250 kW
- $20,000 for 250 kW to 1 MW
- $55,000 for 1-5 MW
- $65,000 in excess of 5 MW.

Cadmus (i) adopted those rates for all TPO commercial systems, Community Solar, and Grid projects; and (ii) assumed all DO and residential systems would not require lease payments. For the out-of-state variant, Cadmus utilized the same U.S. Department of Agriculture land value resource, referenced in the Transition Incentive modeling to assess differences in land values between New Jersey and Virginia (the state chosen as a proxy location in PJM territory).[18] Cadmus evaluated the percentage difference in farm real-estate value between the states, and applied a conservative 40% reduction to the TI modeling assumption to scale down estimated annual lease payments for the out-of-state project.

- **Operations and Maintenance (O&M) Fee** from Transition Incentive modeling assumptions:
  - $35/kW-Year 1 for projects with capacity less than 25 kW
  - $14/kW-Year 1 for 25-500 kW
  - $12/kW-Year 1 for projects with capacity greater than 500 kW

  A premium of $25/kW-Year 1 was added for Community Solar projects.
- **Insurance costs** were also adopted from Transition Incentive Modeling assumptions:
  - 0% of total costs for projects with capacity less than 25 kW
  - 0.27% for projects with capacities 25-250 kW
  - 0.45% for projects with capacity greater than 250 kW
- Opex was generally escalated at 2% per year.

[18] The updated version of the source for TI modeling lease assumptions: *USDA Land Values 2019 Summary – August 2019.*

Table 18. Operating Costs

SAM Case	Capacity Tier	Modeled Capacity (kW)	Project Mgt. Costs [1]	Property Tax/PILOT [2]	Site Lease [3]	Total	O&M Fee ($/kW-yr) [4]	Insurance [5]
	SAM Case Information		Operating Expenditures ($/Year)					
Comm_DO_Ground_lg	1 MW and greater	3,500	$ 5,000	exempt	n/a	$ 5,000	$ 12.00	0.45%
Comm_DO_Ground_med	100 kW up to 1 MW	500	$ 3,000	exempt	n/a	$ 3,000	$ 14.00	0.45%
Comm_DO_Roof_lg	1 MW and greater	2,000	$ 5,000	exempt	n/a	$ 5,000	$ 12.00	0.45%
Comm_DO_Roof_med	100 kW up to 1 MW	350	$ 3,000	exempt	n/a	$ 3,000	$ 14.00	0.45%
Comm_DO_Roof_sm	up to 100 kW	35	$ 17	exempt	n/a	$ 17	$ 14.00	0.27%
Comm_TPO_Carport	n/a	1,500	$ 5,000	exempt	$ 34,650	$ 39,650	$ 12.00	0.45%
Comm_TPO_Ground_lg	1 MW and greater	3,500	$ 5,000	exempt	$ 55,000	$ 60,000	$ 12.00	0.45%
Comm_TPO_Ground_med	100 kW up to 1 MW	450	$ 3,000	exempt	$ 15,000	$ 18,000	$ 14.00	0.45%
Comm_TPO_Roof_lg	1 MW and greater	2,000	$ 5,000	exempt	$ 55,000	$ 60,000	$ 12.00	0.45%
Comm_TPO_Roof_med	100 kW up to 1 MW	250	$ 1,625	exempt	$ 10,000	$ 11,625	$ 14.00	0.27%
Comm_TPO_Roof_sm	up to 100 kW	35	$ 17	exempt	$ 1,000	$ 1,017	$ 14.00	0.27%
CS_Ground	n/a	3,500	$ 5,000	$ 17,500	$ 55,000	$ 77,500	$ 37.00	0.45%
CS_Roof_lg	1 MW and greater	2,000	$ 5,000	exempt	$ 55,000	$ 60,000	$ 37.00	0.45%
CS_Roof_med	100 kW up to 1 MW	650	$ 3,000	exempt	$ 20,000	$ 23,000	$ 37.00	0.45%
Grid_Ground	n/a	7,000	$ 6,337	$ 35,000	$ 65,000	$ 106,337	$ 12.00	0.45%
Grid_Ground_OOS	n/a	10,000	$ 6,337	$ 50,000	$ 39,000	$ 95,337	$ 12.00	0.45%
Grid_Roof	n/a	2,000	$ 5,000	exempt	$ 55,000	$ 60,000	$ 12.00	0.45%
Resi_DO_Roof	n/a	10	$ 17	exempt	n/a	$ 17	$ 35.00	0.00%
Resi_TPO_Roof	n/a	8	$ 17	exempt	n/a	$ 17	$ 35.00	0.00%

Notes:
Source: Primarily adopting TI modeling assumptions from Attachment 1: Pipeline Supply Model Inputs and Assumptions, New Jersey Transition Incentive Supporting Analysis and Recommendations – August 2019.
1. Adopted TI modeling assumption for similar project type.
2. Based on TI modeling rate as follows: $5,000 / MW
3.Based on TI modeling assumptions, adjusted for the first breakpoint: $1,000/year for capacity <60 kW, $10,000/year for 60-250 kW, $15,000/year for 25-500, $20,000/year for 500-1 MW, $55,000/year for 1-5 MW, and $65,000/year for >5 MW. Carports are reduced by 37% to reflect diminished opportunity costs of the land. The cost for the out-of-state case was reduced by 40% to reflect differential land costs (see text).
4. Adopts TI modeling assumptions: $35/kW-yr for capacity <25 kW, $14/kW-yr for 25-500 kW, and $12/kW-yr for >500 kW, as well as a premium for Community Solar as follows: $25 / kW-yr
5. Adopts TI modeling assumptions: 0% total costs for capacity <25 kW, 0.27% for 25-250 kW, and 0.45% for >250 kW.

Financial Parameters

Cadmus relied primarily on financial inputs from the Transition Incentive modeling work, including for the debt share of capital, interest rates, debt tenors, and after-tax equity internal rates of return (IRRs). The following tables present the base year of inputs for the Fixed Incentive type, broken up by PPA SAM Cases (Table 19) and DO (Table 20). The Payback Year target for DO projects was introduced in the Successor Program modeling to accommodate that SAM financial model—see Section 5.1 for a brief discussion.

Table 19. Financial Parameters for PPA Projects

SAM Case	IRR Target	Debt Share	Tenor (years)	Annual Interest Rate
Comm_TPO_Carport	9.7%	52.5%	12	6.0%
Comm_TPO_Ground_lg	9.7%	52.5%	12	6.0%
Comm_TPO_Ground_med	9.7%	52.5%	10	6.0%
Comm_TPO_Ground_sm	9.7%	52.5%	10	6.0%
Comm_TPO_Roof_Lg	9.7%	52.5%	12	6.0%
Comm_TPO_Roof_Med	9.7%	52.5%	10	6.0%
Comm_TPO_Roof_Sm	9.7%	52.5%	10	6.5%
CS_Ground	9.7%	52.5%	12	6.0%
CS_Roof_lg	9.7%	52.5%	12	6.0%
CS_Roof_med	9.7%	52.5%	10	6.0%
CS_Roof_sm	9.7%	52.5%	10	6.5%
Grid_Ground	9.7%	52.5%	12	6.0%
Grid_Ground_OOS	9.7%	52.5%	12	6.0%
Grid_Roof	9.7%	52.5%	12	6.0%
Resi_TPO_Roof	9.7%	47.5%	10	6.5%

Notes:
Source: TI Modeling assumptions.

Table 20. Financial Parameters for DO Projects

SAM Case	Payback Year Target	Debt Share	Tenor (years)	Annual Interest Rate
Comm_DO_Ground_lg	10	52.5%	15	6.0%
Comm_DO_Ground_med	10	52.5%	15	6.0%
Comm_DO_Ground_sm	10	52.5%	15	6.0%
Comm_DO_Roof_lg	9	52.5%	15	6.0%
Comm_DO_Roof_med	9	52.5%	15	6.0%
Comm_DO_Roof_sm	9	52.5%	15	6.0%
Resi_DO_Roof	10	47.5%	13	5.5%

Notes:
Source: TI Modeling assumptions; Payback Year targets based on analysis of related IRR targets.

Cadmus scaled these inputs based on the perceived riskiness per incentive type, as discussed above. For interest rates, the Project Model uses the Fixed Incentive set as a base, adds 50 basis points (0.5%) for the market-trading incentive, and deducts 25 basis points for the Total Compensation incentive. For DO projects, a separate, Payback Year target metric was used, as discussed in Section 5.1.

The project adopted the following additional assumptions:

- Federal income tax: 35% for residential and 21% for commercial.
- State income tax: 5.95% for residential and 9% for commercial.
- All solar project costs assumed exempt from state sales tax.

- Inflation assumed covered by the escalation rates discussed.
- Host owners assumed to be taxable entities, so ITC and federal taxes apply, with appropriate step-downs in ITC percentages.

Revenue/Electricity Rates

DO and TPO projects derive their primary value from electricity sales, via offset electricity costs and PPA revenue, respectively. Of note, SAM allows the user to specify for TPO projects either a PPA price or a target IRR. Cadmus specifies an IRR target as an input, and SAM derives the PPA price that achieves that return. As discussed below, Cadmus increases the State PBI until SAM's PPA price falls to (approximately) the project's target PPA rate.

Cadmus utilizes electricity rates and derives PPA rates for SAM Cases depending on the project type:

- For projects located behind the meter (BTM), PPA prices are derived as a discount to the host's utility tariff rates (discussed further below).
- For Community Solar projects, Cadmus assumes a weighted rate of 60% residential and 40% commercial subscriber rates, per BPU recommendation.
- For Grid Supply projects, the PPA rate is based on wholesale market rates (discussed further below).

Electricity/PPA Rates for Behind-the-Meter Projects

Cadmus used electricity prices for three service classes:

- Residential
- Commercial
- Large C&I

SAM provides the ability to download and integrate into the model utility tariff schedules from OpenEI, an open-source database of electricity and energy-related information developed and maintained by NREL. Cadmus downloaded schedules for the four regulated EDCs' Residential and Commercial service classes:

- Atlantic City Electric (ACE)
- Jersey Central Power & Light (JCPL)
- Public Service Enterprise Group (PSEG)
- Rockland Electric Company (RECO)

The OpenEI rates are shown in Appendix D.

Importantly, Cadmus assumes (for modeling purposes) that solar production only offsets energy-based charges for customer utility bills. While opportunities may exist to reduce demand (kW) based charges at a site, Cadmus' experience indicates difficulties in assessing whether solar production will be coincident with (i.e., will occur at the same time) as a facility's peak demand. Cadmus' March 2020 survey confirmed this: almost all respondents indicated that they did not typically rely on an offset in demand charges, even if it were discussed as a possibility with commercial customers evaluating energy savings.

> ***Modeling Note****: While the reduction of demand charges may not be certain or readily quantifiable with standalone PV, integrating energy storage systems should improve the ability to manage demand charges (e.g., by actively "shaving" a facility's peak demand). We welcome feedback from stakeholders regarding their experiences in incorporating demand-charge reductions in their modeling for PV projects and as part of their discussions with prospective customers, particularly in light of energy storage.*

As OpenEI did not provide complete rates for Large C&I customer classes for all EDCs, Cadmus compiled energy- (kWh-) based charges from EDCs' tariffs. The derivations of those Large C&I rates are provided in Appendix F.

Rate schedules typically include seasonal pricing and sometimes include multitier pricing, based on a usage (in kWh) breakpoint. In order to set a single, PPA price for a SAM Case, Cadmus calculated a single, weighted electricity price. Cadmus used the higher-tier rate where applicable and weighted seasonal rates by approximate shares of solar energy generated in the respective months (40% in utilities' summer-season months, June through September, and 60% in winter-season months, October through May). After a single, weighted rate was calculated for a service class in a utility, a 15% discount was applied to derive the PPA rate.

Tariff rates were adjusted annually for each service class. Stakeholder feedback advocated using growth rates that reflect additional costs associated with new clean energy programs. Cadmus used growth rates of 2.5% and 2.4% annually for residential and commercial rates, respectively, as gleaned from the March 2020 Survey (again, with Community Solar as a weighted average).

Of note, Cadmus assumes direct and third-party owners focus only on the energy component of utility charges and do not evaluate values from reducing demand charges (i.e., solar offsets kWh-based charges and not assumed to offset capacity- (kW-) charges). Stakeholders confirmed such in their feedback from the March 2020 Survey.

> ***Modeling Note****: For Large C&I tariff rates, Cadmus used a simple average within each season to derive LMP prices. For future modeling, prices could be weighted by solar production for a representative project.*

PPA Rates for Grid Supply Projects

PPA revenue for Grid Supply projects reflects revenue that the project could earn in wholesale markets. Section 4.8 discusses wholesale market-rate sources and assumptions. PPA rates for Grid Supply projects are calculated by combining energy (+ ancillary) prices with adjusted capacity prices, as shown in Table 21.

Table 21. Derivation of Combined Wholesale and Energy Prices

Steps to Derive Combined MWh Rate	Units	Calculations	Results
Forecast 2020 NJ Capacity Prices (kW-based)	*$/kW-year*	A given	$ 57.94
NJ Capacity Prices (MW-based)	*$/MW-year*	B=A*1,000	$ 57,940
ICAP MW value for Solar PV (% nameplate)	*%*	C given	42.0%
Capacity value per MW	*$/MW*	D=B*C	$ 24,335
Capacity factor	*%*	E given	16.3%
Energy per MW (aka SEP)	*MWh/MW*	F=E*8,760	1,428
Capacity payment per MWh	*MWh*	G=D*F	$ 17.04
Forecast 2020 NJ Energy (+ Ancillary Services) Prices [1]	*$/MWh*	H given	$ 29.99
Combined energy and capacity prices (per MWh)	*$/MWh*	I=G+H	$ 47.02

Notes:

Sources: Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions, Technical Memo, Green Building (Table 1) for energy prices; 2019 State of the Market Report for PJM, Monitoring Analytics, March 12, 2020 (Table 10-4) for Ancillary Services.

1. As weighted for solar production (see Wholesale Prices section in report).

Incentives

The ITC steps down at prescribed levels: 26% in 2020; 22% in 2021; and thereafter 10% for businesses and 0% for residential.

Bonus depreciation also steps down as specified:

- 100% through 2022
- 80% in 2023
- 60% in 2024
- 40% in 2025
- 20% in 2026
- 0% thereafter

This benefit is only available for PPA financial models in SAM. The commercial direct-ownership minimum incentives, therefore, may be overstated to the extent that commercial hosts can use bonus depreciation.

Cadmus used the State Performance-Based Incentive (PBI) input to solve for the economic return. The SAM Modeling Process section, below, discusses that methodology.

SAM Inputs Setup

Base-model year SAM inputs were stored in Excel as references. Some inputs were hardcoded, while others were parameters based on chosen scenarios/cases. For instance, Cadmus based the financial parameters discussed above on the broad incentive type chosen, reflecting each type's relative riskiness.

As the Successor Program is intended to serve as the primary program, in place for several years, the Project Model has the capability to model 11 years in SAM, representing 2020 through 2030.

Cadmus assumes certain SAM inputs will change over time and applied either growth rates or prescribed schedules over the modeled years:

- **Installed costs:** Growth rates for costs of each component—module, inverter, and BOS—were informed by the March 2020 Survey and by Cadmus research. Module and inverter costs were assumed to decrease at 1.5% and 2.0%, respectively, while BOS costs remained flat.
- **Electricity prices** drove the underlying energy savings value for DO projects and set the basis for PPA prices for TPO projects. These were discussed above.
- **Wholesale prices** drive revenue for grid-scale projects. See Section 4.8 for more discussion on wholesale rates.
- **ITC** and **Bonus Deprecation** rates step down at prescribed schedules, as discussed.

SAM Modeling Process

Cadmus created SAM Cases that reflect different project ownership, installation types, and other characteristics. SAM simulates a project's energy production and cash flows, based on a variety of inputs provided. For the Project Model purposes, Cadmus uses the State PBI input as a proxy for the minimum incentive required to make the project economically viable, based on the project's economic target.

The State PBI variable in SAM can be deployed as an array or schedule field. This allows the user to input values for as many years as desired. Cadmus set the series of State PBIs to match the number of years of assumed project life (25 years). The State PBI is populated in two phases. The first comprises years when the project receives the Successor Program incentive (Incentive Term, analogous to "Qualification Life" in the Legacy SREC program). Cadmus assumes that, in the remaining years of the project's life and beyond, projects will avail themselves of Class I RECs prices.

Cadmus uses SAM's built-in scripting language to automate simulations. The customized script first populates inputs in SAM, extracted from the Excel file for the specific SAM Case. The script creates the State PBI series, using the incentive (starting at $0/kWh) and Class I REC prices, runs a simulation, and checks the economic target. If the target is met, the State PBI is captured as the minimum incentive value required for that year. If the economic target is not met, the script automatically repeats the process, adding $0.005/kWh ($5/MWh) to the previous State PBI. This process is repeated until the economic target is met for the modeling year. Output files, including the annual State PBIs, are generated from SAM, and the data are imported into the Market Model to derive Successor Program costs, as discussed below.

> ***Modeling Note***: *In the event that the BPU determine some or all solar incentives would be set administratively, Cadmus strongly supports conducting a transparent process, with robust cost and technical assumptions that reflect timely data and stakeholders' experience and expectations. In addition to modeling suggestions mentioned herein, we recommend using SAM or a similar industry model, flexible enough to model various types of solar projects (i.e., installations, ownership, economic targets) and vetted by the market. Further, we suggest improving the quality of, and maintaining, cost and technical information from installed and pipeline projects, supplemented by inputs for recent and near-term price estimates from a variety of stakeholders (e.g., via a periodic survey) and recognized industry information sources (e.g., the U.S. Solar Market Insight report, published jointly by the Solar Energy Industries Association and Wood Mackenzie). Finally, we suggest sharing all salient inputs and outputs with the market for review.*

4.2. Market Model Overview

The Excel-based Market Model performs several primary functions:

- Forecasts solar installations by SAM Case.
- Allocates monthly solar installations in the near term (the Transition Period) among three solar programs (tranches):
  - SREC Registration Program (Legacy SREC Tranche)
  - Transition Incentive Program (TREC Tranche)
  - Successor Program (Successor Tranche)
- Incorporates minimum Successor Program incentives, generated through SAM modeling along with forecast installations, to determine Successor Program costs under various scenarios.
- Estimates other components of the Cost Cap.

Cost Cap Overview

Modeling the Cost Cap involves three broad steps:

1. Estimate and compile Class I REC Costs, including those associated with solar (numerator);
2. Derive the Total Paid for Electricity (denominator); and

3. Calculate the result (numerator divided by denominator) and evaluate it against the Cost Cap Test limits.[19]

Cadmus currently models the following components for the numerator and denominator:

Numerator: Class I REC Costs

- Three solar tranches:
  - Legacy SREC Tranche
  - TREC Tranche
  - Successor Program Tranche
- Other Class I RECs

Denominator: Total Paid for Electricity

- Underlying rate-based costs (starting point reflects business as usual)
- Three solar tranches
  - *Changes in* Legacy SREC*
  - TREC Tranche**
  - Successor Program Tranche**
- *Net* offshore wind (OSW) costs to ratepayers (direct cost less market revenue)**
- Zero Emission Credits costs to ratepayers**
- *Changes in* Other Non-Solar Class I costs*

* Assumes rate-based costs incorporated the Legacy SREC costs in the base year, so only apply changes to base
** New costs not reflected in base year, so add full impact each year going forward

> ***Modeling Note**: the BPU is currently reviewing calculations of the Cost Cap Test; therefore, derivations included in this report should be considered very preliminary and, in any case, not representative of the official estimate.*

The following sections discuss Cadmus' calculations of the chief components of the Cost Cap, focusing on derivations of capacity, energy, and cost of the three solar tranches.

19 An amendment to the CEA (S-4275) provides greater flexibility for evaluating the Cost Cap, such that if the Total Paid for Electricity in EYs 2019–2021 were less than the initial 9% cap, the BPU may raise the Cost Cap for EYs 2022–2024 above the initial 7%, provided that total costs for EYs 2019–2024 do not exceed the sum of (i) 9% of Total Paid for Electricity in EYs 2019–2021; and (ii) 7% of Total Paid for Electricity in EYs 2022–2024.

4.3. Forecasting Capacity Growth

The Market Model provides two main methods for forecasting solar installations:

- A "bottom-up" method that estimates annual growth for each SAM Case based largely on historical trends.
- A "top down" method that establishes a target *total* capacity and applies market shares to SAM Cases.

Discussions follow for each of these.

Bottom-Up Forecasting Method

Cadmus analyzed growth of solar installations by Broad SAM Case, annually over the last five years as well as monthly over the last two years.[20] Graphs of these trends are provided in Appendix B. Notably, while Cadmus analyzed equipment lists from March 2020 (provided quarterly), we understand from the BPU that several months can lag for projects to report PTO. Therefore, Cadmus generally focused on installations through December 2019.

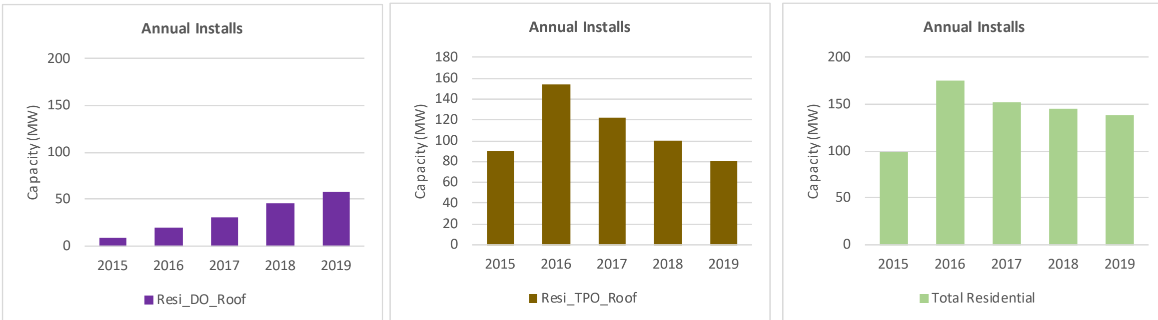
Most SAM Cases showed strong growth over the last five years, especially recent spikes for carports and commercial ground systems. Another notable trend relates to the change in ownership for, as well as a general decline of, residential projects. As shown in the left two graphs of Figure 1, residential DO has grown strongly, while residential third-party ownership has declined in the last few years. This switch has likely been aided by a significant decline in installation prices, and, as lenders have become more comfortable with lending against solar assets, they may have been able to provide better terms.

The growth in DO systems has not completely offset the decline in third-party ownership, however, as the overall residential market has declined, as shown in the right-hand graph below. After reaching a high of 180 MW annual installations in 2016, combined residential installations dropped each year through 2019 at a compounded annual growth (decline) rate of -7%. To meet the state's clean energy goals and to maintain a diversified solar industry, the BPU may want to explore a means of ensuring that residential customers have economical solar options.

With the step-down of the major federal incentive (the ITC), residential customers may be further disadvantaged: the ITC rate steps down, staying at 10% for commercial owners, whereas it goes away altogether for residential owners. The advent of Community Solar, for example, may mitigate the decline in residential systems to some extent, providing an alternative means to access solar for residential customers whose homes may not prove feasible for installations or who are unwilling or unable to invest in a system.

[20] Monthly assessment is conducted through rolling, last-12-month, average installations. Cadmus reviewed the so-called "Broad" SAM Cases (i.e., before splitting into size categories) to streamline the modeling process.

Figure 1. Residential Switch to DO and Overall Decline



Notes
Based on an analysis of installed projects in the March 2020 Equipment List.

Table 22 summarizes Cadmus' observations of SAM Case historical growth. As noted, Community Solar is a new type of project and thus not reflected in historical installs.

Table 22. Observations of Historical Installations by SAM Case

	Observations	
Broad SAM Case	**Longer Term (2015-2019)**	**Near Term (latest 24 months)**
Comm_DO_Ground	jump in 2018 to ~20 MW from low levels; down to 13 MW 2019	generally strong growth up to ~2,000 kW/mo but almost no installs since Nov 2019
Comm_DO_Roof	general strong growth, 17% 2-yr CAGR, >30% 3y and 4y CAGRs; but 10% dip in 2018	steady increase to almost 6,000 kW/mo
Comm_TPO_Carport	jump in 2019 to 25 MW from very low levels	generally new install type; more installs starting June 2019 to ~2,000 kW/mo
Comm_TPO_Ground	jump in 2019 to 60 MW from 12-25 MW/year	from 1,500 kW/mo, strong growth in 2019 to >5,000 kW/mo
Comm_TPO_Roof	jump in 2017 to 58 MW backing off since to <50 MW	general decline from ~5,000 kW/mo to around 4,000 kW/mo
Grid_Ground	spike in 2016 to 136 MW; otherwise general increase from 40 MW to 76 MW	lumpy; generally average around 4,000 kW/mo but large amounts installed in recent months
Resi_DO_Roof	strong growth, 2- and 3-yr CAGRs through 2019 at 32% and 38%, respectively	strong monthly growth up to 7,000 kW/mo
Resi_TPO_Roof	general decline from high of 150 MW in 2016 to low of 76 MW in 2019 (a -21% CAGR)	decline from >8,000 kW/mo level to almost 6,000 kW/mo

Notes:
Based on an analysis of installed projects in the March 2020 Equipment List.

Informed by the analysis above, Cadmus forecasted growth in two phases:

- **Phase 1**: Monthly growth through the Transition Period, allowing for the rollout of the SRP and TREC pipelines and allocation of additional installed capacity among solar programs.
- **Phase 2**: Annual growth following the Transition Period through 2030, the final year of modeling for the Successor Program. Notably, these are relatively conservative percentage growth rates, given historical growth.

Table 23 shows forecasted growth rates by phase.

Table 23. Recommended Growth Rates by SAM Case

Broad SAM Case	Phase 1 (kW/month)	Phase 1 Annualized	Phase 2 (Annual % Change)	
Comm_DO_Ground	2,000	24,000	10%	
Comm_DO_Roof	6,500	78,000	10%	
Comm_TPO_Carport	2,500	30,000	10%	
Comm_TPO_Ground	6,000	72,000	10%	
Comm_TPO_Roof	4,000	48,000	0%	
Grid_Ground	6,000	72,000	7%	
Resi_DO_Roof	5,000	60,000	10%	
Resi_TPO_Roof	5,500	66,000	-5%	
Total	**37,500**	**450,000**		

Notes:
Based on an analysis of installed projects in the March 2020 Equipment List.

Top-Down Forecasting Method

The Market Model provides a method of forecasting solar capacity that establishes total capacity targets by year and allocates that capacity among SAM Cases. The model allows several options for setting annual, total capacities.

For this draft analysis, Cadmus derived the total Successor Program capacity required to meet the State's solar capacity targets. This involved compiling the following information:

- State capacity goals
- Existing Legacy SREC Tranche capacity installed
- Estimated TREC Tranche capacity installed
- Estimated existing solar capacity that might be decommissioned, hence *increasing* overall need.

New Jersey Solar Capacity Goals

Cadmus reviewed solar capacity goals provided in the *2019 New Jersey Energy Master Plan: Pathway to 2050* (2019 EMP), informed by the New Jersey 2019 Integrated Energy Plan (2019 IEP)—especially see the Technical Appendix of the latter document. As part of the Solar Transition (Goal 2.3.2), the 2019 EMP provides a final target of 32,200 MW by 2050 (under the Least Cost scenario). The document also provides milestone capacity targets, including 12,188 MW by 2030, the final modeling year for this exercise.

Legacy SREC and TREC Tranches

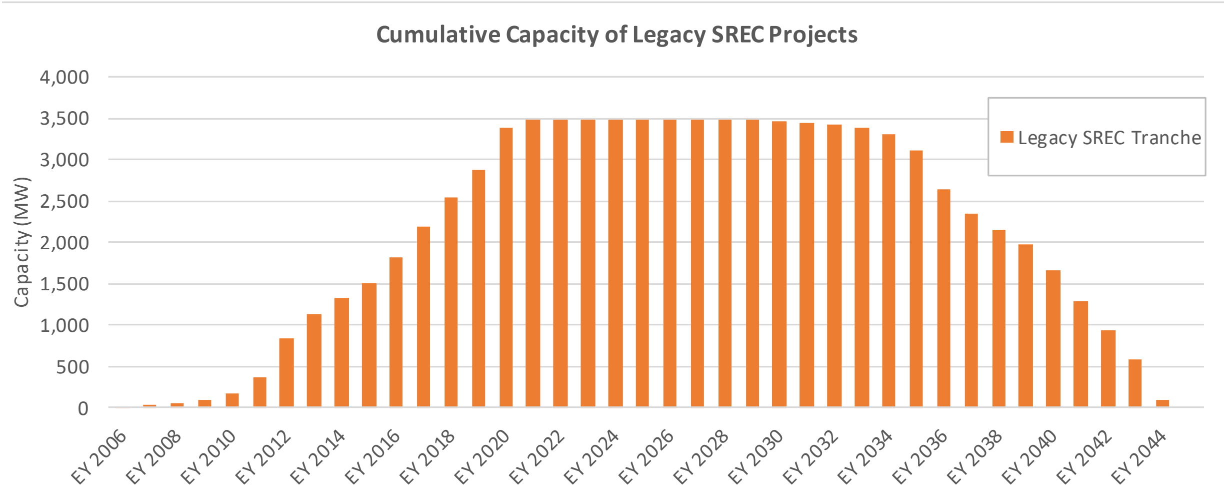
BPU has advised that several months' delay can occur in projects reporting their utility PTO dates, which is used as a proxy for commercial operations. As indicated above, Cadmus used the March 2020 equipment lists for much of the derivation of SAM Cases, related inputs, and analysis for forecasting. To derive the amount of Legacy SREC Tranche capacity through the 5.1% Milestone (end of April 2020), Cadmus used the actual capacity, installed as of December 31, 2019, and added four months' worth of monthly forecasts (mentioned in the "bottom-up" approach). Additional capacity was allocated to the Legacy SREC Tranche and TREC Tranche from the SRP and TREC Pipelines, as discussed above. As discussed, the TREC Tranche also included installations prior to (and as rolled out subsequently following) the Successor Program implementation.

Installed Capacity Falling Off

In reviewing capacity targets, one should consider that projects installed early in the New Jersey solar market development will likely start to be decommissioned in the near term (i.e., a dynamic that reduces installed capacity and increases the need for new capacity to meet State targets). It is difficult to assess when a project will be decommissioned; this may be a function of one or more factors, in particular project equipment warranties, array construction, and provisions in governing project documents. Practical project life should exceed the qualification life (15 years, until recently) by several years. Cadmus has assumed a life of 25 years for projects in each of the solar tranches. The NJCEP installation data begins in 2000; therefore, capacity from those earliest projects could begin falling off in the next few years.

As shown in Figure 2, the impact of this forecasted decommissioning remains relatively low in the near term, tracking the small market in the program's early years. By 2035, however, Legacy SREC installed capacity begins to decline more noticeably and could fall off completely in the 2040s. Capacity from the TREC Tranche and early Successor Tranches may also begin to fall off in that time period.

Figure 2. Decline in Legacy SREC Capacity Over Time



Notes
Forecasts based on an analysis of installed projects in the March 2020 Equipment List. Assumes a project life of 25 years.
NJCEP installation data begins in 2000; since the first few EYs are very small relative to the ultimate scale, the graph starts in EY 2006.

Cadmus recommends that the BPU consider surveying owners of older projects to understand decommissioning's impact on capacity goals. The BPU should also consider investigating the likelihood of project repowering, which could provide owners with an opportunity to take advantage of the following:

- existing project infrastructure, relationships, and contracts
- advances in module efficiencies, power electronics capabilities, and design
- declines in project costs

Project owners may choose to repower earlier than 25 years, depending on contract terms and other constraints.

Given the likelihood of Legacy SREC and TREC project capacity "falling off" in later years, the Successor Program (and any other complementary/subsequent programs implemented) will need to account for replacing those projects in order to meet targets.

Gap for Successor Program

Using information compiled from the above steps, Cadmus estimated the total capacity needed (Gap) for the Successor Tranche through EY 2030, as shown in Table 24.

Table 24. Total Capacity Needed from Successor Tranche

Derivation Steps	Capacity (MW)	Comments
2030 Total Installed Target	12,188	per 2019 IEP
Less: Installed Legacy SREC capacity end 2019	3,193	per June 2020 Installs report
Less: Incremental Legacy SREC installed	285	forecasts from Phase 1 of bottom-up method for Jan-Apr 2020 plus rollout of SRP pipeline, as reduced
Less: TREC Tranche	641	from Transition Period analysis
Add: Legacy SREC decommissioned capacity by 2030	14	assumes 25-year project life
Gap for Successor Tranche	**8,081**	

The model allows two means of allocating total capacity needed among years:

- Incremental, annual additions to capacity, taking an estimated starting capacity in EY 2021 and growing that by adding the same amount each year to the previous year's installed capacity.
- Even, annual installations, based on the Gap divided by the number of years through the end of the modeling period. Cadmus believes this latter method is less realistic, as installation will more likely grow over time.

Allocation to SAM Cases

The second component of the top-down forecast is allocating each year's target capacity among the SAM Cases. The model uses historical market shares for SAM Cases, derived from historical data, and applies those to a chosen total capacity—the current amount uses the 2019 year-end total, plus a year's worth of Phase 1 forecasted installations from the bottom-up method. Then the estimated capacity for new SAM Cases (Community Solar, out-of-state, and grid roof) is added to create the full set of SAM Cases.

At the BPU's request, the model allows for one of the SAM Case's *pro rata* share of capacity to be adjusted manually, with the remaining SAM Cases absorbing that change based on their shares. The adjusted, *pro rata* shares are applied to the annual capacity targets to forecast each SAM Case's annual capacity.

Community Solar

As discussed, Community Solar falls under a state pilot program, which limits initial installations to 75 MW per year for the first three years. The BPU Staff indicated that, for modeling purposes, Cadmus should assume 150 MW per year is installed thereafter. The *CS Dec 2019 BPU Order* mentioned above requires that projects in the first Program Year must be installed within 12 months of the date of that order (i.e., by December 2020). Therefore, during the monthly transition period modeled, Cadmus assumed that Program Year 1 projects would be installed during the fourth quarter of calendar 2020 and that subsequent Program Year tranches would be installed in their respective fourth quarters. In summary, this means the following:

- 78 MW of projects granted conditional approval for Program Year 1 are installed during the fourth quarter of 2020 (EY 2021).
- 75 MW for Program Year 2 is installed during the fourth quarter of 2021 (EY 2022).
- 75 MW for Program Year 3 is installed in EY 2023.

- 150 MW is installed in each EY thereafter.

> ***Modeling Note****: Cadmus strongly recommends performing a technical and market potential study for solar installations in the state. New Jersey was an early leader in solar in the United States and has developed a robust market. That relatively long history of success in installations, however, suggests that the developer community has likely spent significant time prospecting for optimal projects, and that some of the best opportunities for solar may have been taken already or otherwise did not work under existing market structures. Strong opportunities for expansion may exist, including the following: (i) in traditional segments, as prices continue to decline, and if additional solar-favorable measures are adopted (e.g., siting, permitting, expansion of remote net metering, interconnection coordination/transparency); (ii) emerging segments, such as Community Solar, carports, commercial ground mount, and others. Consequently, Cadmus believes it prudent to understand the possible capacity and electricity generation potential, regardless of cost, policy, or regulatory considerations (technical potential) and the likely amount of PV that can be added, considering a variety of policy and economic scenarios (market potential). Based on Cadmus' experience in producing these reports, this study would first analyze feasible roof and land areas available, along with solar project technical data, to determine a likely upper bound of solar capacity that could be installed in the state. That process would be complemented by consideration and analysis of market factors impacting solar growth, primarily by assessing interaction with project economics.*

4.4. Transition Period Modeling

Overview

Cadmus separately modeled the period of months (Transition Period) when installed projects will change eligibility from the Legacy SREC Tranche to the TREC Tranche to the Successor Tranche. The analysis involved several steps:

- Forecasted growth in installations, as discussed above in the bottom-up forecasting method
- Pared down the pipeline project list to those projects more likely to be installed
- Allocated capacity to tranches

The following sections describe the latter two steps.

Pare Down Pipeline Project Lists

Cadmus used the list of Transition Incentive pipeline projects from the *June 2020 Pipeline List* to estimate the first batch of projects to be installed into the TREC Tranche. This required Cadmus to perform the following steps:

- Derived estimates for the time from application acceptance to project completion
- Pared down pipeline projects as a recognition that not all projects will be built

- Estimated when remaining pipeline projects will become operational

Further discussions of these steps follow. Of note, Community Solar was not included in this analysis, given it has been assigned a prescribed schedule for installation.

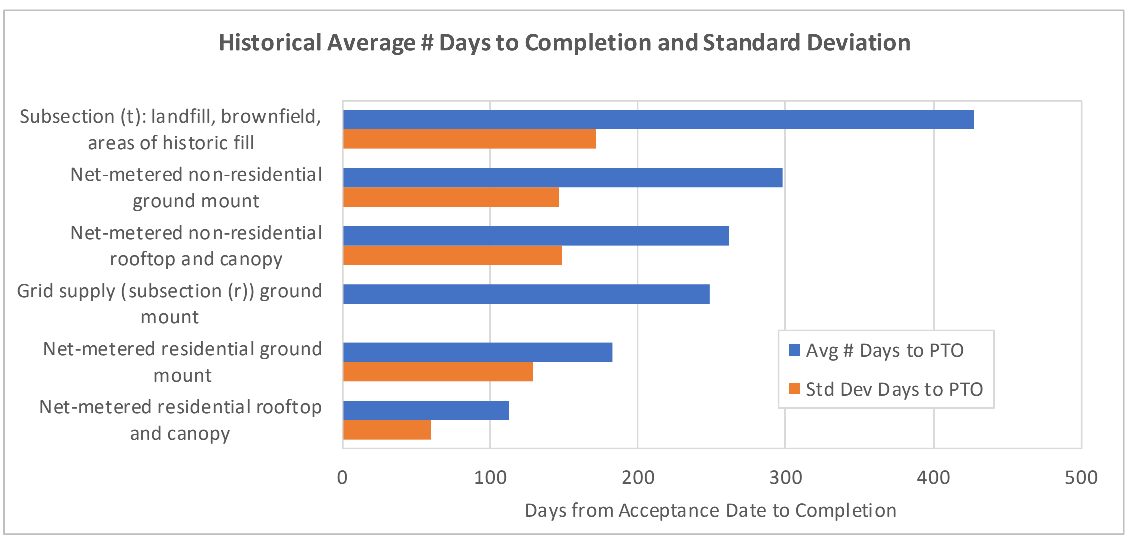
Estimate Time to Completion

Cadmus first derived estimates by TREC Factor Class for “Days to PTO” (i.e., the amount of time that projects usually take to proceed from the date of registration acceptance to the date of the utility’s PTO). The PTO was used as a proxy for when the project is assumed to begin generating energy. Cadmus analyzed installed project data in the *March 2020 Equipment List* and, in addition to exclusions discussed above, omitted records meeting the following criteria:

- PTO Date was older than the last two years
- TREC Factor Class was not applicable
- Acceptance Date was blank
- The number of days from Acceptance Date to PTO was fewer than 30 days (including especially where PTO < Acceptance Date), as those are assumed not representative.

Cadmus calculated average Days to PTO for each TREC Factor Class, as shown in Figure 3. Additionally, the standard deviation was calculated and subsequently used for setting limits on projects’ reasonable completion timelines and for project deployments.

Figure 3. Estimated Time to Completion Based on Installed Projects



Notes:
Based on analysis of installed projects from the March 2020 Project Equipment List.
There were no rooftop Subsection (r) projects applicable for calculations. For analysis purposes, Cadmus used the ground mount version as a proxy.
There were only two Subsection (r) projects. For analysis purposes, Cadmus used the standard deviation for "Net-metered non-residential rooftop and canopy" as a proxy, given the similar average figure.

Pare Down Pipeline List

Cadmus then pared down the Transition Incentive pipeline list as follows:

1. Eliminated projects with Acceptance Dates in the future.
2. Eliminated projects deemed too long outstanding.
3. Performed an additional "scrub" of projects to account for more projects estimated not to reach completion.

To evaluate whether a project has been in the pipeline "too long" after being accepted, Cadmus calculated the average Days to PTO for the TREC Factor Class, plus one standard deviation, as discussed above. This was compared with the number of days elapsed for a project, from its Acceptance Date to the date of the report (June 30, 2020). In addition, several projects had Acceptance Dates in the future (these were excluded). Projects representing approximately 11.3% of total capacity did not pass these initial tests and were excluded from the rollout.

As a second paring-down level, Cadmus adopted results from an earlier analysis, conducted during the Transition Incentive modeling phase and showing a "scrub" rate of approximately 30%. Following the 18.5% (in aggregate) of total capacity excluded in the first pass, Cadmus calculated a follow-on reduction of approximately 14% to match the overall scrub rate from the Transition Incentive modeling. Given the small number of Subsection (r) projects (one ground mount and three rooftop), Cadmus did not exclude any capacity from those TREC Factor Classes. The follow-on reduction was applied to each month estimated across the remaining TREC Factor Classes, resulting in an overall reduction in capacity of 29%.

Table 25 shows the results. Of note, the NJCEP also reported 8.5 MW of projects had already been installed in the TREC Tranche.

Table 25. Paring Down of Transition Incentive Pipeline List

TREC Factor Category	Initial Capacity	Capacity After Reduction 1	Capacity After Reduction 2	Total % Reduction in Capacity
Community Solar	n/a	n/a	n/a	n/a
Net-metered non-residential ground mount	25.4	25.4	20.0	-21.1%
Net-metered non-residential rooftop and canopy	146.3	122.7	96.8	-33.8%
Net-metered residential ground mount	0.4	0.4	0.3	-21.1%
Net-metered residential rooftop and canopy	15.3	14.6	11.5	-24.6%
Subsection (t): landfill, brownfield, areas of historic fill	28.0	28.0	22.1	-21.1%
Total	**215.3**	**191.0**	**150.7**	**-30.0%**

Notes:
Capacity in MWs.
Based on an analysis of the June 2020 Pipeline List. See text for discussion.
Community Solar not included in above analysis, since it is on a separate schedule.
Descriptions of Reductions: (i) Reduction 1: Acceptance Date in the future or time since Acceptance Date exceeded estimated average Days to PTO + 1 standard deviation; (ii) Reduction 2: Further culling to reach overall ~30% "scrub" rate derived in TI modeling.

Cadmus performed a similar analysis and reduction of the SRP Pipeline from the *June 2020 Pipeline List*, with the capacity of pipeline projects falling from 217 MW to 152 MW.

Allocate Capacity to Solar Tranches During Transition Period

On a monthly basis, the model forecasts installations and allocates among the three solar tranches during the Transition Period (through EY 2022). This is meant to build up estimated capacities by Vintage Year, as discussed below.

Capacity is assigned to one of three solar tranches, based on the following criteria:

- Contained in the SRP and Transition Incentive pipelines
- SRP registration completion
- Achievement of 5.1% Milestone
- Lag (if any) in the implementation of the Successor Program
- Project's operational status

Cadmus employed the rules shown below in Figure 4 to assign capacity among the three tranches.

Figure 4. Rules for Assignment to Solar Tranches

Program	Tranche	Installation Capacity Assignment Criteria
SREC Registration Program	Legacy SREC	Approved SRP registration and installed before Achievement of the 5.1% Milestone (4/30/2020), as well as the SRP pipeline (as reduced per above)
Transition Incentive Program	TREC	Approved SRP registration after 10/29/18 but not operational before 5.1% Milestone: Transition Incentive pipeline (as reduced per above) plus incremental installations pending implementation of Successor Program
Successor Program	Successor	Later of (i) approved registrations falling after 5.1% Milestone or (ii) when the Successor Program approved by BPU

On April 6, 2020, the BPU announced that the state had achieved the 5.1% Milestone and would preemptively close the Legacy SREC program, effective April 30, 2020. Projects would have a 90-day window (i.e., through July 30, 2020) to show a PTO by April 30, 2020, and submit the final, as-built applications. Projects with a PTO after April 30, 2020 (but before a yet-to-be-established Successor Program eligible date) would be eligible for the TREC Tranche. As Cadmus understands that (i) there can be delays in projects reporting their PTO, and (ii) there is uncertainty around the allocation of projects between Legacy SREC and TREC Tranches, the Market Model allocates near-term capacity as follows:

- All forecasted, monthly installations from January through April 2020 were allocated to the Legacy SREC Tranche.
- The SRP and Transition Incentive pipelines from the June 2020 pipeline list were reduced per the above analysis and "rolled out" over a number of months, based on the estimated time to completion.
- For modeling purposes, Cadmus assumed the Successor Program would be implemented in December 2020, but certain projects would be installed in the TREC tranche for several (less than 12) months thereafter.

The Transition Period extends long enough to capture any residual TREC Tranche installations; for modeling purposes, the incremental TRECs were not allowed to install after the end of 2021 (12 months after assumed implementation of the Successor Program).

4.5. Legacy SREC Tranche Cost Derivation

Modeling to derive costs for the Legacy SREC Tranche involved three main steps:

1. Calculate annual capacity
2. Generate energy based on that capacity
3. Determine costs associated with the SREC obligation.

Discussions follow for each of these steps.

Cadmus used the *June 2020 SRP Installed List* to aggregate installed capacity by Vintage Energy Year, based on the date of projects' PTO from the utility. Cadmus understands installed capacity may be undercounted in the latest months, so, as with the forecasting method discussed above, we counted only projects with PTO through December 31, 2019.

Recent projects were further broken out by their eligible SREC Qualification Life. As clarified by the BPU in its *SREC Registration Program Update,* dated October 29, 2018, projects must have had their application received by that date. Cadmus used the Completion Date field in the *Installed List* data to split capacity into groups with 15-year and 10-year Qualification Lives.[21] Additional capacity, as discussed in the forecasting section above, was generated for the Legacy SREC Tranche prior to achievement of the 5.1% Milestone.

Each Vintage Energy Year's capacity was projected for the term of SREC eligibility (Qualification Life number of years, either 10 or 15)—e.g., extending the 290 MW installed in EY 2013 for 15 years through EY 2027.

In each Energy Year, Cadmus aggregated capacities from all eligible Vintage Energy Years. To derive estimated energy production and thus estimated SRECs, a single SEP was applied to the capacity. Cadmus used an "aged" SEP of 1,154 MWh/MW, calculated in an analysis of New Jersey's solar fleet energy production performance by PJM EIS for the BPU.[22] This SEP presumably reflected the projects' module degradation as well as other potential performance and availability issues.

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21 Certain projects had a blank Completion Date field, but Cadmus used other dates to assign Qualification Life. Projects showing Completion Dates after the cutoff date above but which had a PTO prior to EY 2019 were nevertheless allocated to the 15-year Qualification Life.

22 Source: *New Jersey Solar Performance –Supplemental Analysis*, PJM EIS, January 8, 2020.

> ***Modeling Note****: Given the level of EIS' "aged" SEP for the fleet relative to SEPs derived in SAM for the Successor Program Model, it may be that SAM modeling has an overall energy degradation rate higher than assumed, or additional adjustments should be made to SAM default losses, which would reduce the initial SEPs. A reduction in starting SEPs and/or an increased energy degradation rate would reduce overall energy production and suggests, therefore, that higher incentives would be needed.*

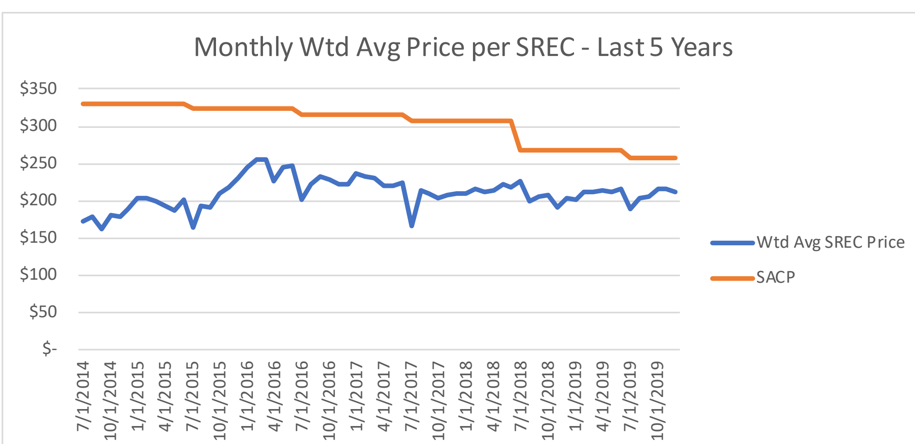
Costs for the Legacy SREC Tranche are based on how load-serving entities (LSEs), subject to the solar carve-out of the Renewable Portfolio Standards, comply with their obligations. LSEs either purchase SRECs and retire them or make SACPs.

The model uses the solar carve-out percentages prescribed in the CEA through EY 2033 and adjusted RPS compliance reports to reflect Basic Generation Service staggered auctions.

The Market Model allows for five years of banking (i.e., an SREC can be used for compliance in the year in which it was generated or in any of four subsequent years). Surplus SRECs not retired for compliance are added to the "Banking Account" and extracted from that account to meet obligations on a first-in, first-out method. If a residual deficit remains after the Banking Account has been completely depleted, the shortfall is assumed to require SACPs. Based on Cadmus' estimates, sufficient SRECs should generally be generated in each EY, with only a small number of SACPs required during EY 2022 and EY 2023, as the overhang of Basic Generation Service obligations falls away.

Cadmus evaluated several SREC price series, including historical prices; base, low, and high cases from Transition Incentive modeling; and assumptions from stakeholders for a percentage of the SACPs. As shown in Figure 5, historical SREC prices have remained fairly steady during the last few years, despite declining SACPs. As SREC prices averaged about 80% of SACP during 2019, Cadmus used that level for pricing Legacy SRECs.

Figure 5. Historical SREC Prices



Energy Year	Cumulative Wtd Avg SREC Price
EY 2015	$ 192.64
EY 2016	$ 226.05
EY 2017	$ 220.35
EY 2018	$ 216.05
EY 2019	$ 217.29

Sources: Monthly Cumulative Average Weighted Prices (CWAP) reports from the New Jersey Clean Energy website. Cumulative weighted average SREC prices from NJCEP compliance report EY 2005-2019.

Modeling Note: *The model starts with a zero balance for the SREC Banking Account. To the extent already banked SRECs existed at the end of EY 2019, there would likely be even less need for SACPs.*

4.6. TREC Tranche Cost Derivation

For each of the TREC Factor Classes, as shown in Table 26, Cadmus built up energy production and costs separately. Cadmus estimated annual energy production for 15 years in each Vintage Energy Year for which capacity was "installed" for the TREC Factor Class—see the discussion above. The first year of production is based on that Factor Class's Year 1 SEP, assigned from comparable broad project types used for the SAM Cases. The Degradation Rate (0.5%) was applied to subsequent years.

Finally, each Vintage Energy Years' energy production is aggregated in each Energy Year to determine total energy for the Factor Class.

Table 26. TREC Tranche SEPs and TREC Factors

TREC Factor Class	Broad Project Type Proxy	Year 1 SEP (MWh/MW)	TREC Factor
Subsection (t)	Grid Ground	1,428	1.00
Grid supply (Subsection (r)) - rooftop	Grid Roof	1,340	1.00
Net-metered non-residential rooftop and canopy	Commercial Roof	1,376	1.00
Community solar	Weighted Year 1 SEP [1]	1,308	0.85
Grid supply (Subsection (r)) - ground mount	Grid Ground	1,428	0.60
Net-metered residential ground mount	Commercial Ground	1,419	0.60
Net-metered residential rooftop and canopy	Residential Roof	1,247	0.60
Net-metered non-residential ground mount	Commercial Ground	1,419	0.60

Notes:
1. Weighted by share of Community Solar for Commercial Ground (20.4%), Commercial Roof (19.7%), and Residential Roof (60%).

Of note, the Market Model provides for partial-year production, so the capacity, energy production, and resulting costs are shifted ahead by a certain number of months. Currently, Cadmus assumes all projects begin producing energy mid-year (July) of their Vintage EY.

The Market Model uses total energy in MWh (a.k.a. TRECs for this tranche) for two purposes: (1) TRECs are part of the solar carve-out of Class I REC requirements; and (2) TRECs are multiplied by their respective factor shown in Table 26 and by the constant TREC price of $152 to derive TREC Tranche costs for the Cost Cap.

4.7. Successor Tranche Cost Derivation

The Market Model builds energy for the Successor Tranche, utilizing a method similar as that used for the TREC Tranche, using capacity in each Vintage EY and the SAM Cases' SEPs. Energy production is adjusted (shifted out) for partial-year production.

Costs are based on energy production and incentive values. Minimum incentives by SAM Case and Energy Year are uploaded to the Market Model from the SAM modeling results, and then applied to energy production derived for each SAM Case and each Vintage EY to show minimum total costs for the forecasted market capacity.

4.8. Other Market Modeling and Assumptions

Wholesale Prices

Successor Program modeling uses wholesale prices in several ways. The Project Model assumes that Grid Supply projects generate energy revenue through participation in energy, capacity, and ancillary services wholesale markets. Consequently, rates from those revenue sources are used as PPA rates for Grid Supply projects. Cadmus adopted wholesale energy and capacity prices derived in the May 1, 2019, update of the *Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions, Technical Memo*, produced each year by the Rutgers Center for Green Building for the NJCEP. Wholesale energy prices in that memo are broken down into four periods: Summer Peak, Summer Off-Peak, Non-Summer Peak, and Non-Summer Off-Peak.

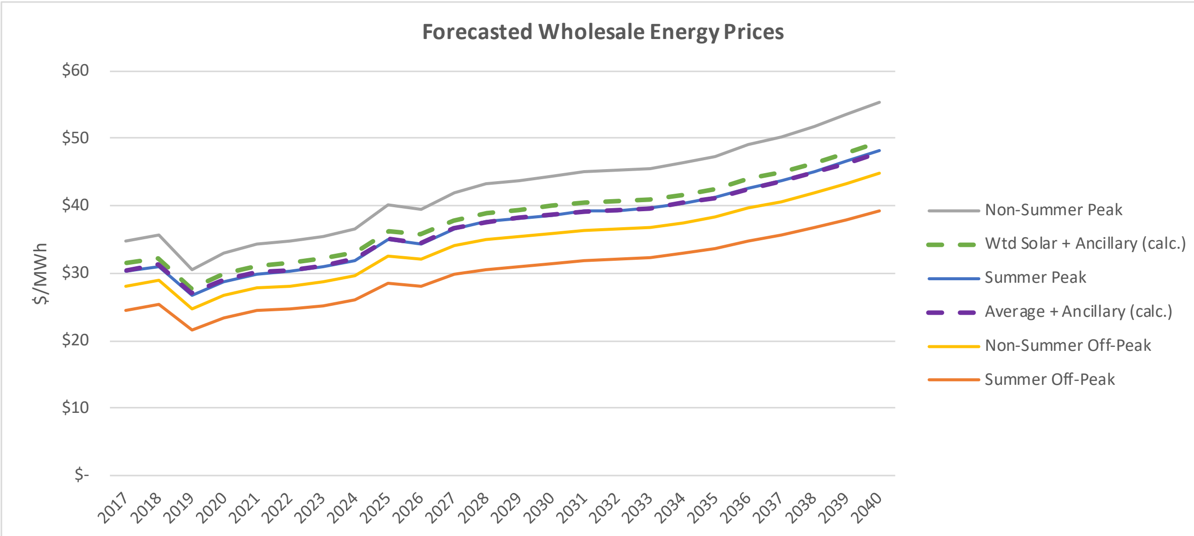
Cadmus used hourly energy production data generated in SAM for the Grid_Ground SAM Case to weight the four periods by the system's output. The memo also recommends adding an amount to energy prices an amount to reflect ancillary services (e.g., regulation, scheduling, dispatch and system control, reactive power, synchronized reserves). Cadmus accessed the most recent, annual version of that value from the report referenced in the memo.[23]

In addition to providing revenue for Grid Supply solar projects, wholesale rates are used in the Market Model to derive market revenue for offshore wind. For modeling purposes, Cadmus calculated a simple average of the four periods of energy prices (and included the ancillary services adder, as above).

Figure 6 shows energy prices by period and the two calculated series. Figure 7 shows wholesale capacity prices.

[23] Source: *State of the Market Report for PJM*, Monitoring Analytics, LLC (Independent Market Monitor for PJM), March 12, 2020 (Table 10-4).

Figure 6. Forecasted Wholesale Energy Prices



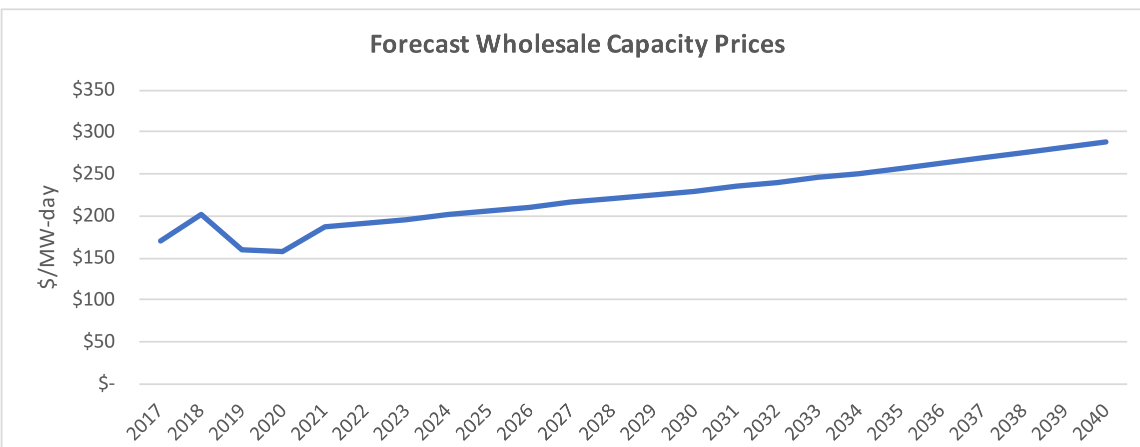
Sources: Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions, Technical Memo, May 1, 2019 Update, Rutgers Center for Green Building (Table 1) for energy prices; 2019 State of the Market Report for PJM, Monitoring Analytics, March 12, 2020 (Table 10-4) for Ancillary Services

Notes:

The Weighted Solar series based on solar energy production for Grid_ground SAM Case during each of the seasonal peak/ off peak periods as defined in the Technical Memo: Summer is May through September; Winter is October through April; on-peak is Monday through Friday 8am-8pm (hour beginning); and off-peak is Monday-Friday 8pm-8am (hour beginning) and weekends and holidays (latter taken from https://www.state.nj.us/nj/about/facts/holidays).

The Weighted Solar series includes an adder for Ancillary Services: $ 1.06

Figure 7. Forecast Wholesale Capacity Prices



Source: Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions, Technical Memo, May 1, 2019 Update, Rutgers Center for Green Building (Table 2). Multipled original $/kW-year by (1,000/365) to convert to $/MW-day.

Cadmus used PJM's Installed Capacity (ICAP) MW value for solar as 42% of nameplate capacity, the Solar Class Average Capacity Factor for ground-mounted fixed panel systems.[24] This component may, however, overstate wholesale revenue available to grid projects as some Grid Supply solar projects may not participate in the capacity market. Further, the Federal Energy Regulatory Commission (FERC) in December 2019 required PJM to expand its Minimum Offer Price Rule (MOPR); so all new projects that benefit from state subsidies (e.g., New Jersey's solar programs) would be required to offer capacity at higher prices than they could on a competitive basis. For instance, PJM proposed a MOPR for solar PV of $387/MW-day for the 2022/2023 Base Residual Auction (BRA). For comparison, in the 2021/2022 BRA Resource Clearing Results, the clearing price was $166/MW-day for the Eastern Mid-Atlantic Region. This FERC ruling on MOPR could further reduce or eliminate grid projects' ability to access capacity markets.

Cadmus calculated compound annual growth rates (CAGRs) for wholesale energy prices over the 2020–2040, using this as the growth rate for Grid Supply PPA prices in SAM.

> ***Modeling Note****: It is anticipated that substantial uncertainty around solar generation resources' ability to access capacity revenues would tend to cause developers to heavily discount such potential revenue sources in forming bids, thus raising prices to consumers. Cadmus understands the BPU has incorporated capacity price true-ups in other contexts, where actual capacity revenues are not known when bids are submitted. Payments are adjusted once actual capacity prices have been determined. Such an approach would accommodate alternative resource adequacy structures, such as those currently under consideration by the BPU in another docket. Cadmus suggests engaging with stakeholders that work with grid-scale projects to understand historical/typical participation rates in capacity markets and the anticipated impacts of the MOPR ruling on their projects. Further, Cadmus suggest developing an approach to mitigating price uncertainty risk.*

Retail Volume Sales

The Successor Program Models use two different measures of retail volume sales (MWh):

- **Compliance Retail Volume Sales**: Sales from LSEs, which are subject to the BPU's jurisdiction and compliance with renewable power standards (RPS). Previously, this was used to forecast the 5.1% Milestone test, though it still is used for compliance obligations (e.g., Legacy SREC, Class I RECs, Class II RECs).
- **Statewide Retail Volume Sales**: Data from the U.S. Energy Information Administration (EIA) ostensibly captures overall sales in the state, including sales by LSEs and other, non-regulated entities (e.g., municipal electric companies). This is used for Cost Cap calculations.

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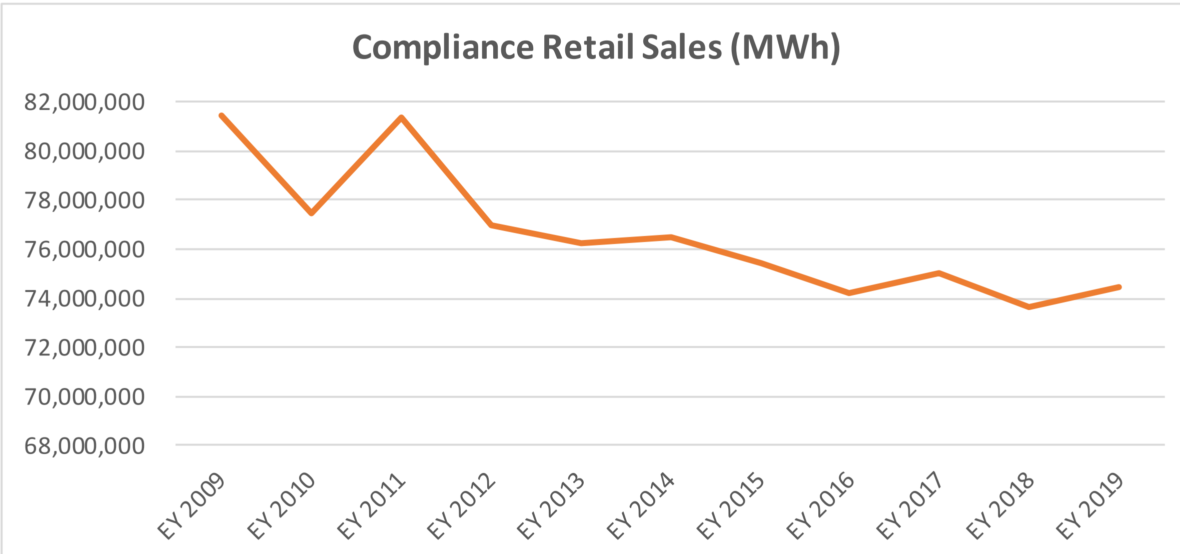
[24] Source: PJM's Default MOPR Floor Offer Prices, 2022–2023 (Excel file). Of note, solar's value is relatively high, as it is based on summer peak hours (i.e., when solar systems are typically generating their highest output).

Compliance Retail Volume Sales

Cadmus reviewed historical compliance sales prior to the BPU's calculations, which have fallen an average of almost 1% per year during the last decade, and generally have been in a tighter band around 74 million MWh in the last few years.

Figure 8. Historical Compliance Retail Volume Sales



Term	Period	CAGR
10-year	EY 2009 to 2019	-0.9%
5-year	EY 2014 to 2019	-0.5%

Notes
The y-axis does not start at 0 MWh.
Source: NJCEP RPS Compliance Reports.

Statewide Retail Volume Sales

Based on EIA data analysis, retail volume sales for the whole state have generally fallen during the last 10 years, in kind with the compliance series; regulated entities represent the vast bulk of the state's load.

Retail Electricity Prices

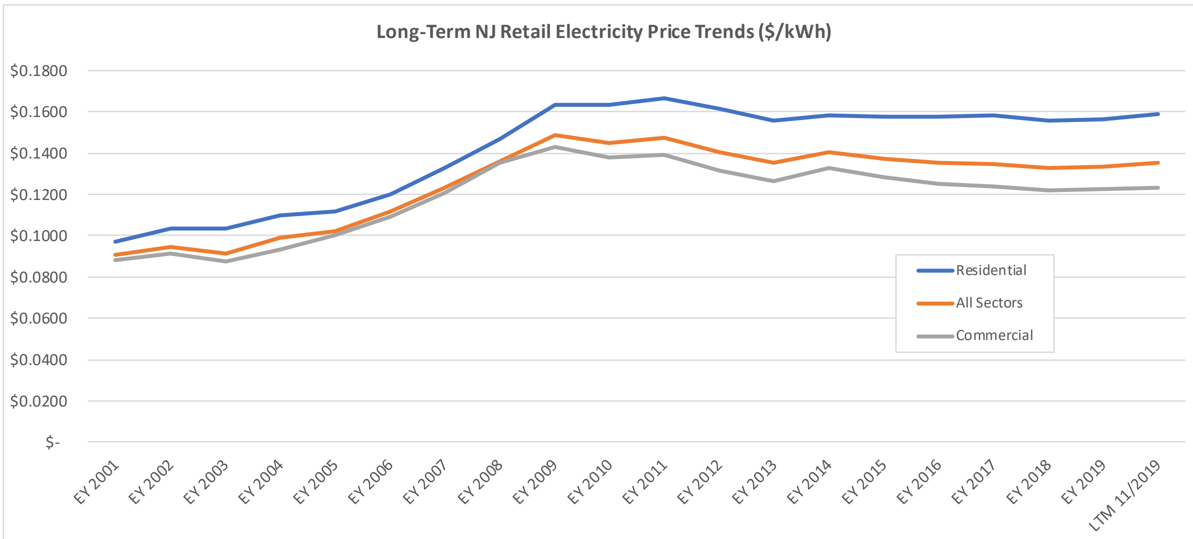
The models use retail electricity prices in two main areas:

- **Statewide Retail Rates**: The Market Model uses market-level, average, retail electricity rates to derive the Total Paid for Electricity component of Cost Cap (discussed below).
- **EDC Tariff Rates**: The Project Model uses EDCs' retail electricity rates in the following ways:
  - directly for DO projects, as the energy value comes from offsetting utility charges
  - indirectly for TPO projects, with the PPA price set at a discount—assumed to be 15%—to utility tariff rates.

Statewide Retail Rates

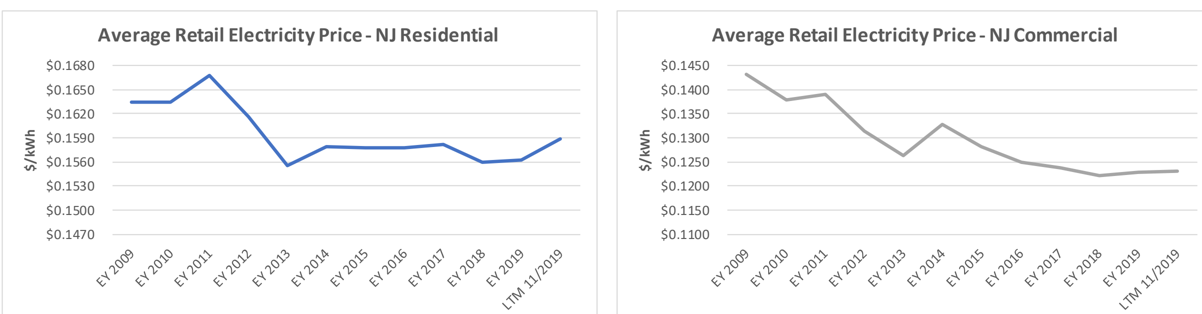
Figure 9 shows statewide, bundled rates for retail electricity from the U.S government's EIA. Rates increased significantly from EY 2001 to EY 2009. Since then, however, rates have generally declined or remained relatively flat, as shown in Figure 10, which uses a narrower vertical axis for illustrative purposes.

Figure 9. Statewide Bundled Retail Electricity Prices, EY 2001-LTM Nov. 2019



Source: EIA.

Figure 10. Residential and Commercial Bundled Rates, EY 2009-LTM Nov. 2019



Residential Price CAGRs

Term	Period	CAGR
10 year	EY 2009-2019	-0.46%
5 year	EY 2014-2019	-0.22%
5.5 year	EY 2014-LTM 11/2019	0.11%

Commercial Price CAGRs

Term	Period	CAGR
10 year	EY 2009-2019	-1.52%
5 year	EY 2014-2019	-1.55%
5.5 year	EY 2014-LTM 11/2019	-1.37%

Notes:
Source: EIA.
The y-axes do not start at $0/kWh.

For Cost Cap purposes, the Market Model uses the discussed Statewide Retail Rates to derive total, rate-based amounts paid. Given the model separately incorporates costs associated with new clean energy programs (i.e., the TREC Tranche, this Successor Tranche, offshore wind, and zero emissions certificates), retail rates for this calculation were kept flat to preventing double-counting those programs' impact. Notably, however, the Market Model does not incorporate costs from any additional programs not reflected in the discussion of the Cost Cap (below).

Offshore Wind

The State of New Jersey promotes OSW development through the Offshore Wind Economic Development Act. Further, OSW serves as a key component of the government's goal to reach 100% clean energy by 2050. The original goal of installing 3,500 MW of OSW through three solicitations was expanded to 7,500 MW through six solicitations. Solicitation winners receive Offshore Wind Renewable Energy Certificates (ORECs), based on energy production. In exchange, the projects return to state revenues earned in wholesale markets.[25]

In June 2019, the first solicitation for 1,100 MW was completed. The OREC price awarded was $98.10/MWh for year 1, escalating at 2% per year through the end of the 20-year term. The state has proposed a schedule for subsequent solicitations. Those solicitations' terms will be determined based on submissions and other factors at that time. For modeling purposes, Cadmus assumed OREC prices decline for subsequent solicitations due to greater economies of scale, improved supply chain/logistics, and/or learning effects. Importantly, FERC's recent ruling on PJM's MOPR (discussed above) could have a significant negative impact on market revenues available to these projects. In turn, that may impact economically viable OREC prices.

Table 27. Modeled Terms of OSW Solicitations

		Solicitation #					
Term	**Unit**	**1**	**2**	**3**	**4**	**5**	**6**
Capacity	*MW*	1,100	1,200	1,200	1,200	1,400	1,400
Award Date	*quarter*	Q2 2019	Q2 2021	Q2 2023	Q1 2025	Q1 2027	Q1 2029
Est. Year of Initial Operation	*year*	2024	2027	2029	2031	2033	2035
OREC Price - Year 1	*$/MWh*	$ 98.10	$ 95.00	$ 93.00	$ 91.00	$ 89.00	$ 87.00
OREC Term and Project Life	*years*	20	20	20	20	20	20
OREC Escalation Rate	*%/year*	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Sources: see footnote in text.

Cadmus provided three deployment cases—base, low, and high—with the base case shown in Table 28.

[25] Sources: "Governor Murphy Announces Offshore Wind Solicitation Schedule of 7,500 MW through 2035" on the State's website: https://www.nj.gov/governor/news/news/562020/20200228a.shtml); and "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Ørsted's Ocean Wind Project" on the State's website: https://nj.gov/bpu/newsroom/2019/approved/20190621.html.

Table 28. Base Case OSW Deployments

	Deployments (MW) by Solicitation						
EY	**1**	**2**	**3**	**4**	**5**	**6**	**Total**
EY 2023	400	-	-	-	-	-	400
EY 2024	700	-	-	-	-	-	700
EY 2025	-	400	-	-	-	-	400
EY 2026	-	400	-	-	-	-	400
EY 2027	-	400	400	-	-	-	800
EY 2028	-	-	400	-	-	-	400
EY 2029	-	-	400	400	-	-	800
EY 2030	-	-	-	400	-	-	400
EY 2031	-	-	-	400	400	-	800
EY 2032	-	-	-	-	500	-	500
EY 2033	-	-	-	-	500	400	900
EY 2034	-	-	-	-	-	500	500
EY 2035	-	-	-	-	-	500	500
Total	**1,100**	**1,200**	**1,200**	**1,200**	**1,400**	**1,400**	**7,500**

The Market Model builds up energy production by each Vintage EY of installation, as done for some solar tranches. The model then estimates: (i) OREC revenue, based on the OREC pricing, a capacity factor of 55%, and a partial year of operation; and (ii) market revenue, based on wholesale energy and capacity payments, using a PJM ICAP MW value of 26% of nameplate capacity (see Section 4.8).

While the CEA explicitly excluded OREC costs as a Class I REC cost in the numerator for the Cost Cap calculation, the *net* cost of OSW (OREC revenue less market revenue) was added to the denominator of the Cost Cap ratio to reflect OSW's ultimate impact on Total Paid for Electricity.

Other Cost Cap Components

Class I RECs

Estimating Class I Costs required determining the compliance obligation and using a REC price. The CEA prescribed the RPS Class I requirements: 21% starting in 2020, 35% in 2025, and 50% in 2030. Through EY 2019, the Legacy SREC program was not treated as a true carve-out of Class I. For the Market Model, each solar tranche was deducted from the Class I compliance obligation, using total TRECs (i.e., MWhs prior to factorizing). For simplicity, Cadmus assumed that all Class I obligations would be filled by purchases of Class I RECs (i.e., no ACPs would be required).

Cadmus reviewed historical Class I REC prices per RPS compliance reports as well as Class I REC price forecasts provided in the October 2018 report, commissioned by the BPU: *New Jersey Regional Greenhouse Gases Initiative Re-Entry* (RGGI Re-entry Report). As shown in Figure 11, while recent prices are close in magnitude, forecast values show a significant spike in later years. Transition Incentive modeling used a base case of $7/REC. The Market Model currently adopts that price for all forecast years. Changes in Class I REC costs are added to Total Paid for Electricity for the Cost Cap calculation.

Figure 11. Class I REC Prices

Sources: RGGI Re-Entry Report and RPS compliance reports.

Zero Emission Credits

Another program under the CEA provides Zero Emission Credits to nuclear power plants in the state. The Market Model uses the same assumption as the Transition Incentive modeling: the program is expected to add $290 million in incremental costs for each of three Energy Years 2020 through 2022. These amounts were added to Total Paid for Electricity.

Class II RECs

The estimates for Class II REC costs follow the same methodology as those used for Class I RECs. This requirement is assumed to remain constant at 2.5% of Compliance Retail Volume Sales. As with Class I RECs, the model assumes that obligations are met through retiring Class II RECs. The price used—$5.37 per Class II REC—derives from the EY 2019 compliance report. The change in Class II REC costs are added to the Total Paid for Electricity.

Underlying Rate-Based Electricity

The total base amount was calculated as Statewide Retail Volume Sales, multiplied by the Statewide Retail Price. EIA provided EY 2020 volume sales and rates as the last 12 months, ending November 2019.

5. Analysis and Modeling of Successor Program

5.1. Treatment of Direct Ownership Projects

As discussed, SAM Cases using the DO financial model evaluate savings from electricity charges. One of the metrics associated with DO projects in SAM is Payback Period, the number of years required to offset the initial investment.

Transition Incentive modeling used the IRR metric for all modeled projects, including DO projects. Based on Cadmus' experience, reinforced by stakeholder feedback from the March 2020 Survey, residential solar customers (i) typically prioritize the Payback Year metric over the IRR and (ii) look for payback closer to seven years. Therefore, as part of the residential DO project analysis, Cadmus first modeled the residential DO SAM Cases using the target IRR indicated during TI modeling of 12-13%. Cadmus then derived the equivalent Payback Period, which was about 10 years.

Payback Period evaluates cumulative cash flows from project inception on an annual basis to determine when the initial investment is fully paid off. This compares to IRR, which accounts for all cash flows during the project's life and evaluates those cash flows on a present-value basis. Given the nature of the Payback Period metric—i.e., that the metric does not contemplate cash flows beyond the year that Payback Period is achieved—Cadmus adjusted the Incentive Term to match the Payback Period, as shown in the top row of Table 29.

Table 29. Residential Direct Ownership Incentive

SAM Case	Incentive Level	Incentive Term	Payback Period
Resi_DO_Roof - 10-year payback	$ 85	10	10
Resi_DO_Roof - 7-year payback	$ 225	7	7

<u>Scenario information:</u>

Incentive Type	Fixed Incentive
Incentive Term	As indicated above
Modeling Year	Year 1
Utility	PSEG

The initial Payback Period was longer than what Cadmus understands that prospective residential DO customers typically seek. For illustrative purposes, Cadmus reduced the target Payback Period for the residential DO target to seven years. This required a higher minimum incentive to meet the target. As with the 10-year Payback Period, Cadmus matched the incentive term to the Payback Period, as shown in the bottom row of Table 29. For a summary of the cash flows that comprise the Payback Period, comparing the 7- and 10-year variants, see Appendix E.

Modeling Note*: Cadmus also assessed commercial DO SAM Cases and found longer Payback Years than may be considered for those projects. Given, however, that those customers purportedly focused on IRR, Cadmus modeled to IRR for commercial projects.*

5.2. Assessing Minimum Successor Program Incentive Levels

This section reviews the results of SAM project-level modeling, which provides the minimum incentives needed for specified SAM Cases to meet their target economic objectives. This includes reviewing results from several, key perspectives that could impact policymaking by comparing minimum incentive levels:

- Among the SAM Cases
- Over time during the modeling period
- Different Incentive Terms
- Among the EDCs
- Between the three main incentive types

For illustration purposes, Cadmus used certain default parameters:

1. A subset of SAM Cases as representative among ownership and tariff classes: Comm_DO_Roof_med, Grid_Ground, and Resi_TPO_Roof (Representative SAM Cases).
2. Typically chose Fixed Incentive, the basic incentive type modeled (as State PBI), falling between the other two incentive types in terms of risk levels.
3. Usually models a 15-year Incentive Term.

Comparing SAM Cases

SAM Cases were chosen as representative of different project performance and cost profiles. Table 30 shows the range of modeled SAM Cases for the Fixed Incentive type. From this, Cadmus makes several observations:

- Comm_DO projects generally need a lower incentive than their Comm_TPO counterparts as the former rely on cost savings valued at full retail prices, whereas the latter rely on PPA revenue that reflects a discount to offtakers' retail rates. The Resi_DO example was modeled with an Incentive Term matching the target Payback Year metrics (i.e., shorter than their TPO counterpart and requiring a higher incentive). Comm_DO projects also avoid other costs, such as lease payments.
- Projects with cost adders (i.e., carport, Community Solar) need relatively higher incentives to overcome those incremental costs.
- Community Solar projects benefit from higher PPA rates relative to commercial projects on a similar scale as Community Solar rates were calculated at a 15% discount to a blended electricity rate (i.e., 60% residential and 40% commercial classes).
- Ground-mount projects tend to require relatively low incentives, as they generally benefit from scale and can optimize their solar production.
- Projects in 2021 typically require a higher PBI than their 2020 counterparts due to a stepdown in ITC from 26% to 22%.

Table 30. Comparison of Minimum Incentives among SAM Cases

	PBIs ($/MWh)	
SAM Case	2020	2021
Comm_DO_Ground_lg	$ 60	$ 65
Comm_DO_Ground_med	$ 75	$ 80
Comm_DO_Roof_lg	$ 65	$ 70
Comm_DO_Roof_med	$ 80	$ 85
Comm_DO_Roof_sm	$ 100	$ 110
Comm_TPO_Carport	$ 170	$ 180
Comm_TPO_Ground_lg	$ 95	$ 105
Comm_TPO_Ground_med	$ 135	$ 140
Comm_TPO_Roof_lg	$ 105	$ 110
Comm_TPO_Roof_med	$ 135	$ 140
Comm_TPO_Roof_sm	$ 150	$ 155
CS_Ground	$ 50	$ 55
CS_Roof_lg	$ 55	$ 60
CS_Roof_med	$ 90	$ 100
Grid_Ground	$ 85	$ 85
Grid_Ground_OOS	$ 50	$ 50
Grid_Roof	$ 90	$ 90
Resi_DO_Roof [1]	$ 85	$ 95
Resi_TPO_Roof	$ 85	$ 95

Scenario information:

Incentive Type	Fixed Incentive
Incentive Term	15 years [1]
Modeling Year	Years 1 and 2
Utility	PSEG

Notes:
1. Resi_DO_Roof has an incentive Term of 10 years, in kind with the target Payback Period (see text for discussion).

Comparing Incentives over Time

Cadmus ran simulations through 2030. Table 31 shows Representative SAM Cases. Cadmus highlights results that follow from three key, driving factors:

- The step-downs in ITC and Bonus Depreciation reduce tax benefits for projects; all projects require increased incentives during the first two years, particularly as the ITC steps down from 26% in 2020 to 22% in 2021 to either 10% for commercial or 0% for residential in 2022 to compensate for lost value.
- While dominated by the federal incentive step-downs in the early years, general reductions in installed costs, modeled over the years, reduce the incentive levels needed. Of note, the grid project starts at a relatively low-cost level and experiences a less-pronounced reduction in required incentive.
- Rising retail electricity prices increase the value of energy (from savings for DO projects and from PPA revenue for TPO projects) and reduce required incentives over time.

For most SAM Cases, incentives typically follow the same general pattern: increasing in 2021 and 2022, followed by a steady decrease over the rest of the modeled years.

Table 31. Comparison of Minimum Incentives Over Time

SAM Case	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Comm_DO_Roof_med	$ 80	$ 85	$ 110	$ 105	$ 105	$ 105	$ 100	$ 100	$ 100	$ 95	$ 95
Grid_Ground	$ 85	$ 85	$ 100	$ 100	$ 100	$ 95	$ 95	$ 95	$ 95	$ 90	$ 90
Resi_TPO_Roof	$ 85	$ 95	$ 130	$ 125	$ 120	$ 120	$ 115	$ 110	$ 105	$ 100	$ 90

Scenario information:

Incentive Type	Fixed Incentive
Incentive Term	15 years
Modeling Year	All years
Utility	PSEG

Comparing Incentive Terms

Simulations performed in SAM typically assumed a 15-year Incentive Term (i.e., the project would become eligible for the incentive for 15 years) in kind with the TREC incentive. At the BPU's request, Cadmus looked at a 10-year Incentive Term. A shorter incentive, *ceteris paribus*, would likely need to be higher than a 15-year incentive. Although from a discounted-cash-flow perspective, achieving revenue sooner provides some counterbalancing benefits.

Table 32, which compares 10- and 15-year incentives for Representative SAM Cases, illustrates the need for a generally higher 10-year incentive. As discussed, Cadmus is solving for DO projects' Payback Year, which does not evaluate the entire project's cash flows (as would an IRR target).

Table 32. Comparison of Minimum Incentives by Incentive Term

	Incentive Year	
Representative SAM Cases	10 Years	15 Years
Comm_DO_Roof_med	$ 80	$ 80
Grid_Ground	$ 100	$ 85
Resi_TPO_Roof	$ 105	$ 85

Scenario information:

Incentive Type	Fixed Incentive
Incentive Term	As indicated above
Modeling Year	Year 1
Utility	PSEG

Comparing Across EDC Territories

To support steady industry growth and, in particular, to reach the state's robust solar capacity goals, it follows that a key consideration would be to ensure the solar portfolio is diversified and optimized geographically. The EDC territories vary in terms of value prospects for solar projects, driven particularly by pricing, but also by interconnection issues/costs, market characteristics, and other solar-development issues.

The following tables show breakdowns by EDC. Table 33 shows the breakdown of SAM Case capacity *within* each EDC (i.e., rows under each EDC sum to 100%). Table 34 shows the share of each SAM Case *across* EDCs (i.e., the columns for each SAM Case sum to 100%). These breakdowns indicate where project types have been successfully installed as well as areas for potential growth or areas for further research (regarding why certain projects have not been installed in an EDC). They will also be important in assessing prospective Successor Program costs. Finally, the BPU could investigate regions of potential growth in areas not covered by EDCs (e.g., almost 8% of the capacity of Grid_Ground projects was located outside EDCs' territories, including a significant share in Vineland Municipal Electric Utility's service territory).

Table 33. Breakdown of SAM Case Capacity within Each EDC

Broad SAM Case	ACE	JCPL	PSEG	RECO
Comm_DO_Ground	3.9%	3.2%	4.2%	0.0%
Comm_DO_Roof	10.2%	11.1%	24.3%	25.1%
Comm_TPO_Carport	0.6%	2.1%	1.0%	16.8%
Comm_TPO_Ground	10.8%	13.0%	6.7%	4.0%
Comm_TPO_Roof	9.2%	14.3%	22.3%	33.0%
Grid_Ground	10.5%	28.9%	16.7%	0.0%
Resi_DO_Roof	11.8%	7.3%	7.4%	9.4%
Resi_TPO_Roof	43.0%	20.2%	17.4%	11.7%
Total by EDC	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Notes:
Based on an analysis of installed projects in the March 2020 Equipment List.
Excludes capacity (i) from SAM Cases not modeled and (ii) from other utilities

Table 34. Share of SAM Case Capacity Across EDCs

Broad SAM Case	ACE	JCPL	PSEG	RECO	Total Across EDCs
Existing projects [1]					
Comm_DO_Ground	17.5%	31.0%	51.5%	0.0%	**100.0%**
Comm_DO_Roof	10.1%	24.0%	64.6%	1.3%	**100.0%**
Comm_TPO_Carport	6.7%	52.8%	30.5%	10.0%	**100.0%**
Comm_TPO_Ground	18.8%	49.4%	31.4%	0.4%	**100.0%**
Comm_TPO_Roof	9.1%	30.5%	58.7%	1.7%	**100.0%**
Grid_Ground	8.9%	53.2%	37.9%	0.0%	**100.0%**
Resi_DO_Roof	24.7%	33.1%	41.2%	1.0%	**100.0%**
Resi_TPO_Roof	32.1%	32.6%	34.8%	0.5%	**100.0%**
Community Solar [2]					
CS_Ground	31.5%	30.9%	37.6%	0.0%	**100.0%**
CS_Roof	0.0%	23.8%	76.2%	0.0%	**100.0%**

Notes:
1. Based on an analysis of installed projects in the March 2020 Equipment List.
   Excludes capacity (i) from SAM Cases not modeled and (ii) from other utilities.
2. Based on an analysis of provisionally approved projects for Program Year 1.
   Excludes capacity from SAM Case (carport) not modeled.

Retail electricity prices in the state vary by customer class (residential, commercial, and large C&I) and by utility territory; Section 4.8 provides further discussion of retail prices. Table 35 shows the following for representative residential and commercial SAM Cases: (i) the lowest electricity rates, resulting in the highest minimum incentives; and (ii) the highest rates, resulting in the lowest minimum incentives. The table reflects that the range of electricity prices (and therefore minimum incentive levels) can vary significantly across the utilities. However, the small variation between Large C&I electricity rates results in a relatively tight range of required incentives across the four EDCs for projects in that service class.

Grid PPA projects rely on wholesale prices, so their minimum incentive levels are not impacted by the utility territory (although some differences may occur in interconnection costs and/or permitting, which this report does not model, though these could be incorporated).

Table 35. Rate Ranges by EDC and Service Class

		Lowest Rate/Highest PBI			Highest Rate/Lowest PBI		
Representative SAM Cases	Service Class	Utility	Electricity Rate ($/kWh)	PBI Incentive ($/MWh)	Utility	Electricity Rate ($/kWh)	PBI Incentive ($/MWh)
Resi_TPO_Roof	Residential [1]	JCPL	$ 0.1426	$ 130	ACE	$ 0.1899	$ 70
Comm_DO_Roof_med	Commercial [1]	PSEG	$ 0.0634	$ 80	ACE	$ 0.1550	$ -
Comm_DO_Roof_lg	Large C&I [2]	PSEG	$ 0.0473	$ 65	ACE	$ 0.0580	$ 45

Scenario information:

Incentive Type	Fixed Incentive
Incentive Term	15 years
Modeling Year	Year 1
Utility	As indicated above

Notes
1. Electricity rates from OpenEI via SAM.
2. Derived from EDCs' tariffs.

Of particular note are PSEG's relatively low commercial rates. As discussed, DO commercial projects derive value from solar energy by offsetting EDCs' energy-based charges. The Project Model assumed that TPO commercial projects set a PPA rate with a 15% discount to energy-based utility charges. In both ownership scenarios, PSEG's relatively low rates make projects less economical than those in other territories. Indeed, the table indicates relatively high incentive requirements for commercial projects in PSEG's territory, in comparison to those in other EDC areas. In the residential segment, minimum incentives are similar across the ACE, RECO, and PSEG territories, which have similar rates. JCPL's minimum incentives are higher, with those rates several cents-per-kWh lower than for other territories.

Given solar growth goals and some significant disparities among EDC areas for required project incentives, it is important to coordinate incentive planning and solar program implementation with the EDCs. For example, EDCs could identify areas on their grids where additional solar capacity would prove particularly beneficial. Projects in those areas could be provided with incentive "adders"; conversely, areas with high existing or anticipated solar penetration will require careful planning. As discussed, it would be prudent to perform a market potential study for solar, seeking to better understand the capacity potential, key characteristics, and constraints of different regions within the state.

EDC Differentiation

As discussed, the State PBIs modeled for each SAM Case represent the minimum incentive value for a representative project. If actual incentives offered to the market matched the minimum incentives required (e.g., through precise factoring), costs would reflect those State PBI proxies multiplied by energy production from the forecasted capacity from the respective SAM Case. That would represent the Fixed Incentive type.

Given the range of electricity prices among the utilities discussed above, Cadmus analyzed two methods to apply incentives for a representative set of projects:

- Applying the same incentive across the state
- Differentiating by EDC territory

In using a statewide rate for each SAM case, Cadmus assumed the BPU would want to incentivize installations across the territories to match the current mix. This would ostensibly require the incentive for each SAM Case (or whatever differentiation might be used for project types) to match the highest incentive among the EDCs. As discussed, project-level incentives in ACE territory are generally much lower, given residential and commercial electricity prices are highest there. On the other hand, commercial projects in PSEG territory tend to require the highest incentives, given at least some commercial rates are much lower than elsewhere and commercial projects comprise the most capacity.

Alternatively, the BPU could optimize incentives by offering different rates in each utility territory, thereby reflecting different electricity prices, which translate into different energy savings profiles or PPA revenues. Cadmus weighted the costs by the distribution of capacity for each SAM Case among the EDCs, as shown in Table 34. In other words, incentives were matched to project incentive needs based on utility rates. Modeling suggests that such a differentiated approach could reduce program costs compared to setting incentives based on the lowest-common costs that suggest the highest incentives. On the other hand, differentiation adds complexity and likely requires additional data requirements and analysis.

Comparing Incentive Types

Cadmus ran SAM simulations for Representative SAM Cases using the risk-adjusted financial inputs. Table 36 shows that, as modeled, incentive risk increases from left to right, and estimated required compensation also increases.

Table 36. Comparison of Year 1 Minimum Incentives by Incentive Type

Representative SAM Cases	Total Compensation	Fixed PBI	Market with Floor
Comm_DO_Roof_med	$ 75	$ 80	$ 85
Grid_Ground	$ 70	$ 85	$ 90
Resi_TPO_Roof	$ 55	$ 85	$ 100

Scenario information:

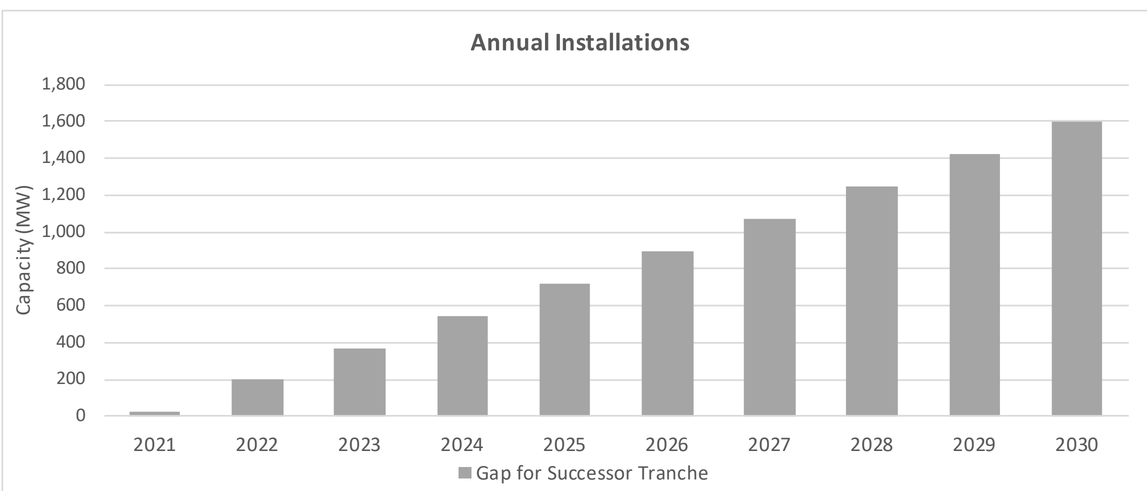
Incentive Type	As indicated above
Incentive Term	15 years
Modeling Year	Year 1
Utility	PSEG

5.3. Successor Program Capacity Targets

EMP Targets

In Section 4.3, Cadmus discussed the State's solar capacity goals, as stated in the 2019 EMP/IEP reports. As part of the bottom-up forecasting approach, Cadmus estimated the total "gap" capacity required to meet the interim 2030 target, based on existing capacity, anticipated TREC capacity and prospective reductions in Legacy SREC project installations as old projects are decommissioned. Again, the Market Model allows for multiple methods to allocate the gap among years through 2030. In Figure 12, for illustrative purposes, Cadmus shows growth in even MW increments.

Figure 12. Target Successor Program Capacity Annual Additions



Notes

Gap for Successor Tranche to achieve the 2019 EMP 2030 Target allocated to show consistent, annual growth.

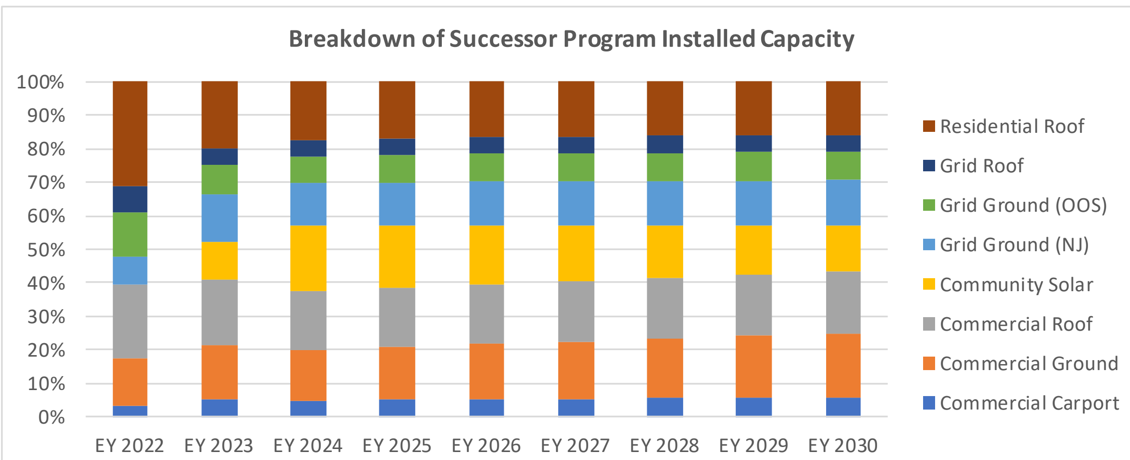
Bottom-Up Forecasts

As discussed in Section 4.3, the Market Model forecasts solar installed capacity using one of two methods:

- A bottom-up approach, with each SAM Case assigned its own growth rates based on an assessment of historical performance
- A top-down approach that forecasts aggregate growth and allocates among SAM Cases.

Figure 13 shows the percentage breakdown of cumulative capacity by SAM Case, based on bottom-up forecasts. The emergence of the Community Solar segments reflects the BPU's assumptions for the pilot program and thereafter; the 150 MW/year level that begins in EY 2024 (installed in the fourth quarter of 2023) becomes a smaller share of overall installed capacity.

Figure 13. Annual Successor Program Installed Capacity by Broad Project Type



Forecasts based on an analysis of installed projects in the March 2020 Equipment List and other assumptions for new SAM Cases discussed in the report.

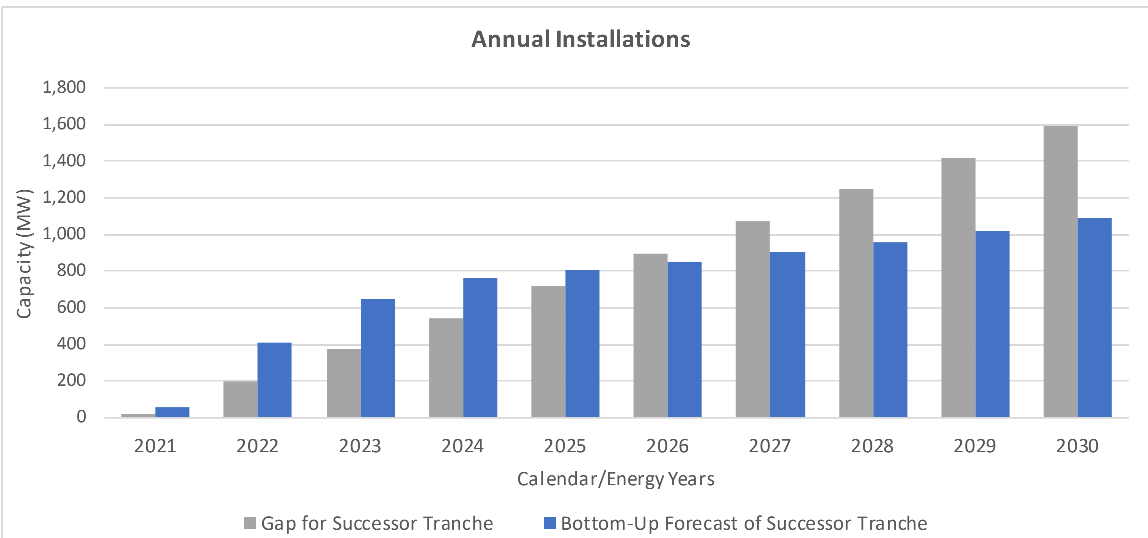
Importantly, growth trajectories for the "historical" SAM Cases are based primarily on historical data and installation trends, and do not reflect certain areas of future growth potential:

- **Improving or optimizing conditions for existing segments**: The absence or low representation of a particular project type may reflect a fundamental shift or existing issue with economics, value propositions, or some other project aspects. For example, the long-term shift from third-party to DO was prompted at least partly by overall reductions in project costs and banks becoming more comfortable lending against PV assets. Alternatively, segments or subsegments with low or declining representation may provide a growth opportunity. Certain commercial rooftops on buildings with low loads, for example, may not have had the opportunity to optimize their PV systems' capacity or may have chosen not to build at all, given net metering constraints. Cadmus recommends identifying segments with underlying impediments and determining whether such issues can be mitigated.
- **Emerging or future new (sub)segments**: Technological advancements, development innovations, and regulatory and rulemaking adjustments may create opportunities for new

project segments or subsegments. Stakeholders pointed to innovations and solutions such as dual-use solar-agriculture, floating solar, and building-integrated PV. Cadmus recommends gathering unique cost and design aspects as well as benefits and impacts of these projects to determine the optimal way (if any) to integrate them into the Successor Program.

As discussed, the Market Model forecasts growth of the modeled SAM Cases through EY 2030, with relatively conservative annual growth rates for the historical SAM Cases. The graph in Figure 14 compares the model's bottom-up forecast growth method with a smoothed growth case for the 2030 EMP targets (shown earlier in this section). While the series show different growth patterns, the bottom-up forecast meets approximately 93% of the total gap over the period (note that the gap series reflects calendar years, whereas the Successor Program series reflects Energy Years).

Figure 14. Comparison of 2019 EMP Target and Successor Program Modeled Installation



Notes
Successor Tranche growth forecasts based on an analysis of NJCEP installed projects as of March 30, 2020.
Annual "gaps" for Successor Tranche to achieve the 2019 EMP 2030 Target were allocated to show consistent, annual growth.
Of note, the Successor Tranche reflects Energy Years, whereas the gaps represent calendar years.

Top-Down Forecasting Allocations

As discussed in Section 4.3, the Market Model allows for a top-down forecasting method, whereby aggregate capacity is forecast and allocated *pro rata* to SAM Cases, based on their market (capacity) share. Employing that method, users can change the market share for one SAM Case. The Market Model adjusts the remaining SAM Cases' shares, which "absorb" the change in capacity on a *pro rata* basis.

For illustrative purposes, Cadmus performed an analysis using the following assumptions:

- The "historical" SAM Cases had market shares based on capacities resulting from the SAM Case derivation.

- The initial, aggregate capacity for just the historical SAM Cases comprised an annualized Phase 1 monthly forecast using the bottom-up method.
- "New" SAM Cases were strictly additive (i.e., not offsetting any "historical" SAM Cases) and were assigned initial installed capacities, as shown in Table 37.

For Grid_Ground_OOS, the initial market share was about 8%. Cadmus increased that to 15%. Using Year 1 SEPs (Table 15) and minimum incentives estimated from SAM (Table 30), Cadmus found that the total cost declined by about 3%.

Table 37. Top-Down Capacity Re-Allocation Example

SAM Case	Historical % Share	Initial MW (Historical)	New Case MW	Initial MW	Initial % Share	Absorption % Share	Adj. to MW	New MW	New % Share
Comm_DO_Ground_lg	2.0%	9.3		9.3	1.5%	1.7%	(0.7)	8.6	1.4%
Comm_DO_Ground_med	0.8%	3.6		3.6	0.6%	0.6%	(0.3)	3.3	0.5%
Comm_DO_Roof_lg	7.5%	34.4		34.4	5.6%	6.1%	(2.6)	31.8	5.2%
Comm_DO_Roof_med	10.3%	46.9		46.9	7.7%	8.4%	(3.5)	43.4	7.1%
Comm_DO_Roof_sm	1.8%	8.4		8.4	1.4%	1.5%	(0.6)	7.7	1.3%
Comm_TPO_Carport	4.8%	21.7		21.7	3.6%	3.9%	(1.6)	20.1	3.3%
Comm_TPO_Ground_lg	7.6%	34.8		34.8	5.7%	6.2%	(2.6)	32.2	5.3%
Comm_TPO_Ground_med	1.0%	4.4		4.4	0.7%	0.8%	(0.3)	4.1	0.7%
Comm_TPO_Roof_lg	3.7%	16.7		16.7	2.7%	3.0%	(1.2)	15.5	2.5%
Comm_TPO_Roof_med	7.2%	32.8		32.8	5.4%	5.8%	(2.4)	30.3	5.0%
Comm_TPO_Roof_sm	0.8%	3.5		3.5	0.6%	0.6%	(0.3)	3.3	0.5%
CS_Ground	n/a		38.3	38.3	6.3%	6.8%	(2.8)	35.5	5.8%
CS_Roof_lg	n/a		29.1	29.1	4.8%	5.2%	(2.2)	26.9	4.4%
CS_Roof_med	n/a		7.6	7.6	1.2%	1.4%	(0.6)	7.0	1.2%
Grid_Ground	21.4%	97.4		97.4	15.9%	17.4%	(7.2)	90.2	14.8%
Grid_Ground_OOS	n/a		50.0	50.0	8.2%	n/a - Driver	41.7	91.7	15.0%
Grid_Roof	n/a		30.0	30.0	4.9%	5.3%	(2.2)	27.8	4.5%
Resi_DO_Roof	12.7%	57.9		57.9	9.5%	10.3%	(4.3)	53.6	8.8%
Resi_TPO_Roof	18.5%	84		84.2	13.8%	15.0%	(6.3)	78.0	12.8%
Total		**456.0**	**155.0**	**611.0**	**100.0%**	**100.0%**	**-**	**611.0**	**100.0%**

Notes:
The light green-highlighted SAM Case is the "driver", i.e., the SAM Case whose market share was manually reset. See assumptions in text.

5.4. Cost Cap

As discussed, Cadmus understands that the BPU is in the process of reviewing the derivation of the Cost Cap Test. This section provides a summary of current calculations, based on assumptions drawn in sections above and the preliminary Cost Cap elements identified in 4.2. The report provides these results solely for illustrative purposes.

in Figure 15's chart, the estimated Total Paid for Electricity breaks down into two main components:

- The baseline amount, forecasted from the EIA-reported Statewide Volume Sales and Statewide Retail Price.
- Aggregated adjustments from new clean energy programs, as broken out in Figure 16.

For illustrative purposes, Cadmus calculated Successor Tranche costs with a SAM Case energy-weighted incentive rate that starts at $87, increases the first couple of years (reflecting the ITC stepdown), and declines over time. Of note, Legacy SREC costs decline compared to the baseline after the first few years as eligible projects fall off. Finally, Figure 17 shows the breakdown of modeled Class I REC costs that will be evaluated against the Total Paid for Electricity.

Figure 15. Total Amount Paid for Electricity

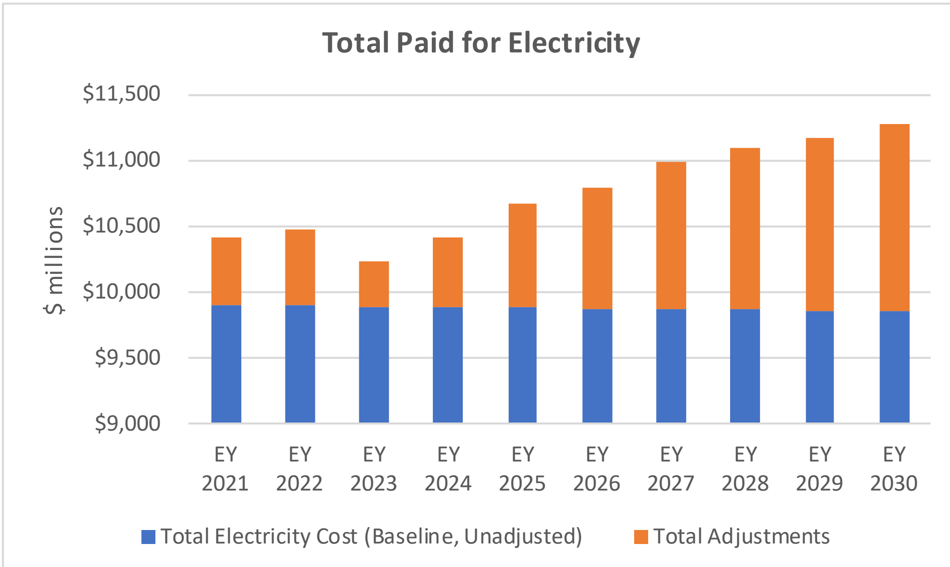
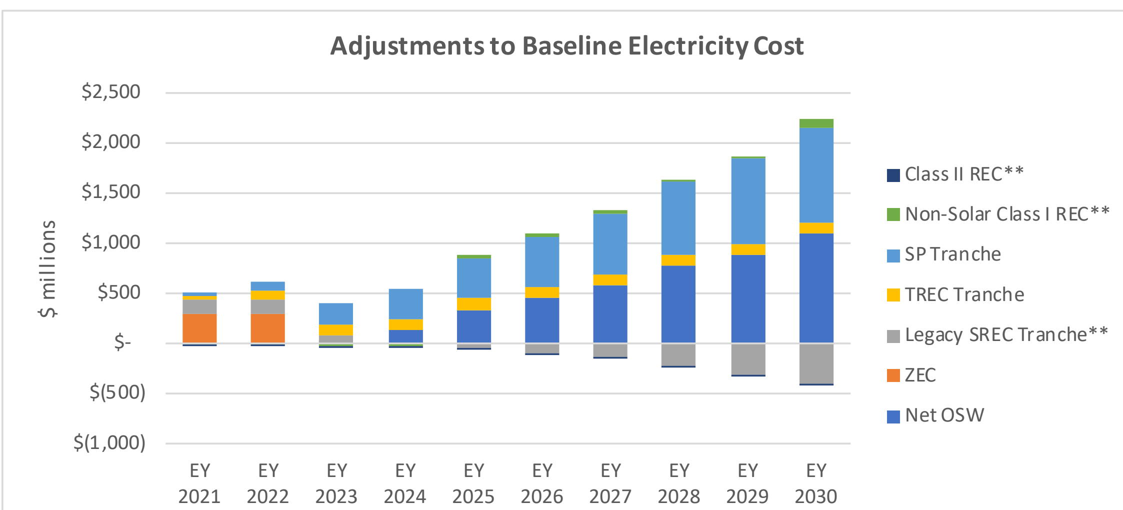
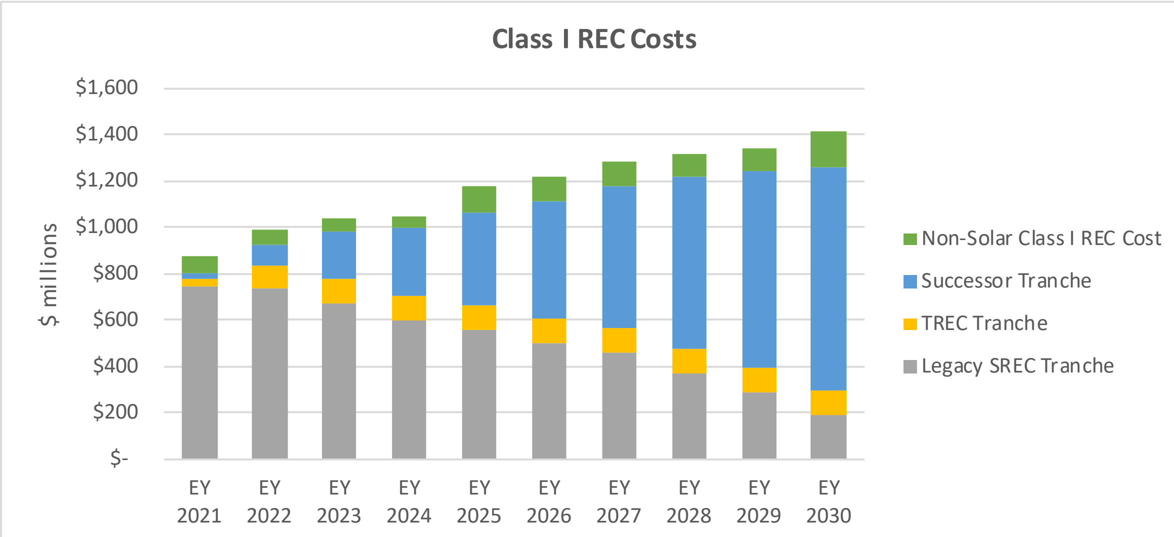


Figure 16. Adjustments to Baseline Electricity Cost



*** Applies only the changes in the program costs compared to baseline year (2019).*

Figure 17. Class I REC Costs By Program



6. Considerations and Recommendations

6.1. Selected Material Considerations

Cadmus believes several recent and ongoing issues could—directly, in combination, or indirectly—impact the ability to estimate near- or medium-term minimum incentives required for solar projects. These should be taken into careful consideration to inform creation of the Successor Program and, at a minimum, prompt annual program reviews:

- **COVID-19**: While the ultimate impact of the global pandemic may take months or longer to emerge, various constraints or political/business reactions to the virus have already imposed or could foreseeably result in a number of material issues for the solar industry:
  - Supply chain disruptions, in particular with a significant share of modules imported from Asia but including constraints on national distribution channels.
  - Impaired or halted property access, especially for smaller projects.
  - Hindered ability to construct projects due to, for instance, worker illness, mandated "social distancing"/"stay-at-home" orders, and associated constraints among crews (although on May 1, 2020, the Governor clarified that solar is deemed an "essential construction project").
  - Inability to market to prospective customers, other than online or mailings.
  - Delays due to authorities with the jurisdiction to issue permits and/or hold required public hearings.
  - Reduced ability to secure tax equity commitments.
  - More conservative financing, including tighter terms and reduced funding availability for new market entrants, borrowers with lower credit quality, and projects with commercial, corporate, utility, and even municipal off-takers, perceived as becoming riskier.
  - Reduced access to capital markets, which have undergone substantial turmoil
- **ITC Stepdown**: The ITC comprises a significant source of value for solar projects over many years. Given the relative importance of this federal incentive, the market has developed sophisticated, if complex, financing structures and has tapped niche sources of "tax equity" capital to monetize tax credits. The credit step-down will likely pose significant implications for project economics and financing structures. Further, the COVID-19 pandemic may result in compounding effects in terms of availability of taxable income, tax equity capital, and access to bank debt.
- **Ongoing Cost Cap Proceedings**: Cadmus understands that the BPU currently engages in proceedings and internal discussions regarding calculation of the Cost Cap imposed by the CEA. Given the prominence of solar in the state's renewable energy portfolio and of the Successor Program to New Jersey's renewable energy goals, these proceedings intertwine strongly.
- **Section 201 Tariffs**: Trade tariffs placed on cells and modules imported from China have disrupted project procurement, prompted some domestic production, and created greater pricing uncertainty. While the trade tariffs are stepping down, it is important to understand how

this and any adjustments impact the solar market. For example, in April 2020, the Trump Administration rescinded its exemption for bifacial modules under the tariffs. Relatedly, in May 2020, the President issued an Executive Order seemingly prohibiting purchases and/or transfers of bulk-power electrical equipment "designed, developed, manufactured, or supplied, by persons owned by, controlled by, or subject to the jurisdiction or direction of a foreign adversary." Implementing such a prohibition might impact large-scale solar and/or energy storage projects associated with solar projects.

- **FERC Orders**: The recent FERC decision on MOPR could substantially constrain or eliminate a revenue stream for grid supply projects, even with potential adjustments for Solar's estimated cost. Further, while FERC recently rejected a petition that sought to invalidate net energy metering (NEM) statutes and regulations, arguing that NEM should fall within FERC's wholesale jurisdiction, efforts may continue to roll back NEM provisions.

6.2. Recommendations

Based on stakeholder feedback, analysis of New Jersey's (and other) programs, and modeling at project and market levels, Cadmus provides the following primary recommendations:

- **Maintain flexibility**. As discussed, Cadmus strongly recommends implementing a flexible program that allows for re-evaluation revisions, particularly over the near term. The myriad, significant changes impacting the solar market—such as those mentioned above—could have material implications for project costs, financing structures, and program elements.
- **Implement a Fixed Incentive program as a first stage, with potential to evolve towards a more Total Compensation paradigm.** In the near term, Cadmus recommends implementing a Fixed Incentive program. This would provide greater certainty, business visibility, and especially "finance-ability." Further, this would allow for more straightforward implementation than a Total Compensation program; this should be particularly compelling in light of time constraints imposed by the CEA timetable, the amount of effort already spent on the TREC Tranche, and related policy issues absorbing BPU Staff resources during recent months (e.g., Cost Cap proceedings, forecasting the 5.1% Milestone, closure of the Legacy SREC Program, implementation of the TREC program). Further, a Fixed Incentive program would provide flexibility while the BPU, other state entities, and the industry work through various related issues and policies—Cost Cap, net metering, energy storage—while allowing for a greater understanding of potential market impacts from major factors discussed above (i.e., COVID-19 pandemic, step-down of the ITC, and trade tariffs). A Fixed Incentive would leverage TREC mechanisms and administrative efforts, but it also could be deemed a first stage. For example, an evolution of the Successor Program could consider replacing net metering with a solar value-based compensation, which may approximate Total Compensation.
- **Deploy a mix of competitive solicitations and administratively set incentives.** The BPU should consider competitive solicitations for projects in the large-scale segment, which are presumably better able to absorb and effect such a process. This would provide price discovery to compare against modeled minimum incentives that could also act as price caps. Care must be taken, however, to avoid overly aggressive and/or unsustainable bidding that leads to projects

languishing. Incentives for smaller project segments could be set administratively, using flexibility to calibrate to the benchmark price discovery from the competitive solicitation. This could avoid what a stakeholder comment termed the “chicken-or-egg” issue for public sector project auctions—competing developers would not have the PPA locked *ex ante*, and the public entity would have less certainty about which developers could garner incentives. This two-tier process should be built upon robust assumptions (see the next bullet) and an open modeling process, such as the one employed by SAM. For any projects to be eligible, the BPU should adopt current SRP prerequisites for project maturity and consider additional requirements to ensure that less-realistic projects do not crowd out others in a block (e.g., project size-scaled application fees/deposits).

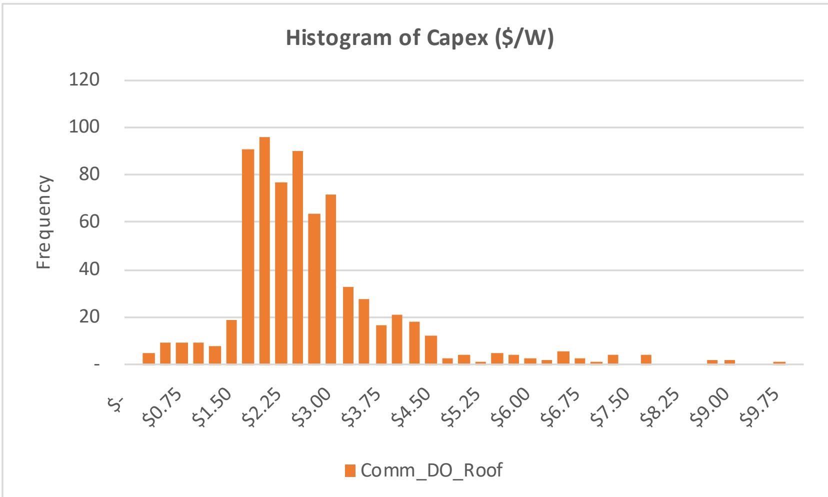
- **Maintain robust estimates of project economics.** The BPU should work closely with developers to gather other data sources for compiling project costs that align with actual project economics and market trends. This could include a mix of recent project costs, price discovery in auctions for larger projects, stakeholder-submitted estimates, and/or stakeholder cost surveys. In particular, the BPU should seek market input on the following:
    - Reasonable, incremental costs for different structures and technologies (such as Community Solar, carport systems, landfill/brownfield, dual-use solar on agricultural land, floating solar, and building-integrated PV).
    - Grid-supply projects’ ability to access revenue sources, particularly their typical reliance on capacity payments and especially in light of FERC’s MOPR rule.
- **Differentiate between project types** to the extent feasible to maximize solar deployment and to ensure a diverse solar portfolio while mitigating cost impacts. Though similar, this should be more expansive than the TREC factor classes to incentivize new segments and optimize growth. The BPU should consider basing these different values on cost differences (such as those modeled by SAM) as well as on policy/social desirability.
- **Differentiate between utility territories** to the extent feasible, since retail rates among the EDCs can vary materially, and utility territories can reflect different load profiles, geographies, and environments. Along with optimizing incentives for different project types, the BPU should consider adjusting incentives for projects in different EDC territories. Other markets, such as New York, Massachusetts, and Illinois, have incorporated some differentiation in their solar incentives for utility zones.
- **Consider treating DO systems differently.** As discussed, DO projects gain primary value from energy savings. Particularly for residential DO projects, customers tend to focus more on a simple payback period metric rather than considering all cash flows from the project’s full life. This may pose implications for incentive structures to meet that objective. A shorter-term, higher incentive may better match that economic target.
- **Conduct a market potential study.** Cadmus strongly recommends analyzing technical potential for solar installations across the state. This should help to identify constraints that could be mitigated as well as growth opportunities. Further, it would aid decision-making on best methods for allocating resources and incentives to optimize solar growth.

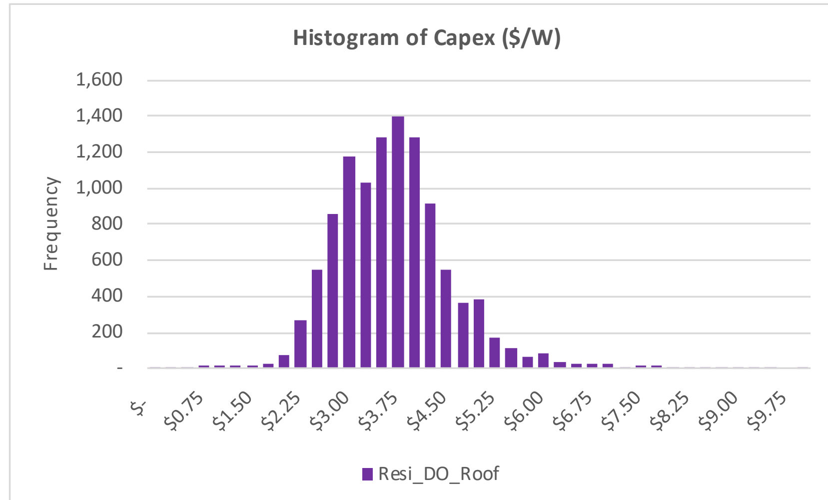
- **Coordinate with related programs**:
  - **Utilities** should closely integrate with the creation and ongoing evaluations of the Successor Program. In doing so, they can help identify grid areas grid with high solar penetration that may prove less desirable for new projects or that require policy or regulatory changes to allow for more solar. Additionally, they can highlight areas that may benefit from additional generation, thus justifying an incentive adder. In several other state markets, for instance, utilities have published maps of their networks that allow developers to understand penetration rates and areas of more/less opportunity.
  - **Net metering** represents a critical value stream for BTM projects and could provide opportunities for additional solar growth. For example, expanding remote net metering could engage a valuable corporate customer segment that would benefit from optimal project siting and scale. Conversely, net metering will likely garner significant attention in the near term, as it has in several markets around the country reaching significant penetration levels. The CEA's milestone of net metering customer-generators reaching 5.8% of electricity sales will likely be reached during the next few years. This trigger (or the run-up to it) would benefit from broad discussions within the industry regarding policy paths for net metering. The BPU could, for example, investigate a replacement for net metering, such as assigning various solar values as a follow-on phase of the Successor Program. Of note, a recent petition before the FERC argued that net metering should fall under FERC's jurisdiction (as wholesale electricity sales).
  - **Other clean energy programs and policy goals** can have a bearing on capacity available under the Cost Cap for the Successor Program and may otherwise directly or indirectly impact Successor Program goals. Close coordination among clean energy programs would preclude programs overlapping or at cross-purposes). For example, Community Solar represents a strong opportunity to grow a new solar segment, but it may cannibalize certain large-scale projects and may pose implications for expanding remote net metering. As the policy goals surrounding low- and moderate-income electricity customers may be met by more than one program, they could benefit from a coordinated, portfolio policy approach. Care also should be taken not to double-count benefits of distributed energy resources among rates, direct incentives, or other mechanisms meant to compensate for the value of distributed energy resources not otherwise reflected in market transactions.
  - **Energy storage** is becoming increasingly viable, not only on a standalone basis but particularly as a complementary technology to solar. Pairing energy storage with solar can provide solar projects with access to additional value streams, reducing the need for incentives. By providing time-shifting capabilities, storage can provide customers with additional value through time-of-use pricing (i.e., helping offset more costly electricity for the utility). Further, energy storage can help reduce demand charges. Given the potential for energy storage to unlock additional value for solar projects, Cadmus finds it crucial for the BPU to investigate ways to incentivize pairing systems, such as applying an "adder," but, of course, this must be done in close coordination with any independent energy storage incentive programs.

- **Evaluate incentives relative to those in the Transition Incentive** to avoid substantial disruptions. Initial incentive levels for the Successor Program that widely vary from the Transition Incentive could result in the market either rushing to build before the Transition Incentive expires or waiting to develop projects until the Successor Program becomes operational. Maintaining some continuity during the program's first year would avoid such market effects.
- **Create working groups.** Convening focused groups of technical experts and stakeholders on a regular basis, with clearly defined objectives, would provide a transparent, effective means to address several recommendations discussed, including interconnection, siting, and related programs.

Appendix A. Examples of Installed Cost Histograms

Table 38. Histograms of Installed Costs

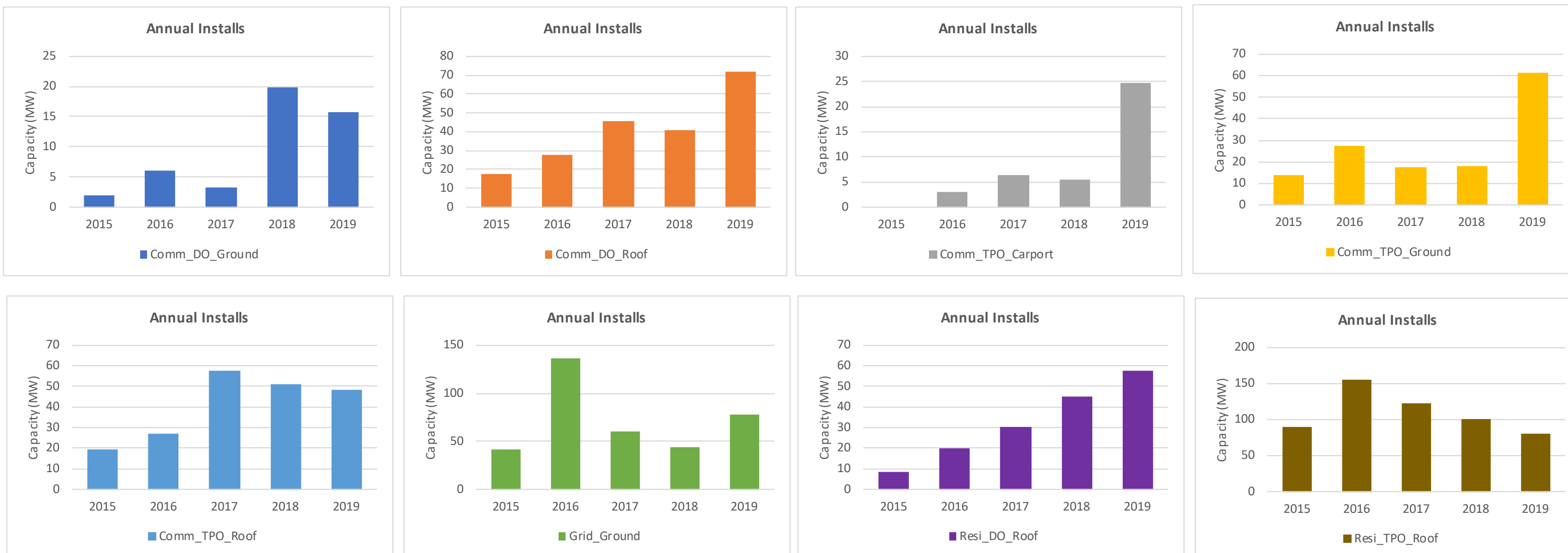




Notes:
Based on analysis of March 2020 equipment lists for installed projects (PTO in 2019-2020) and pipeline.

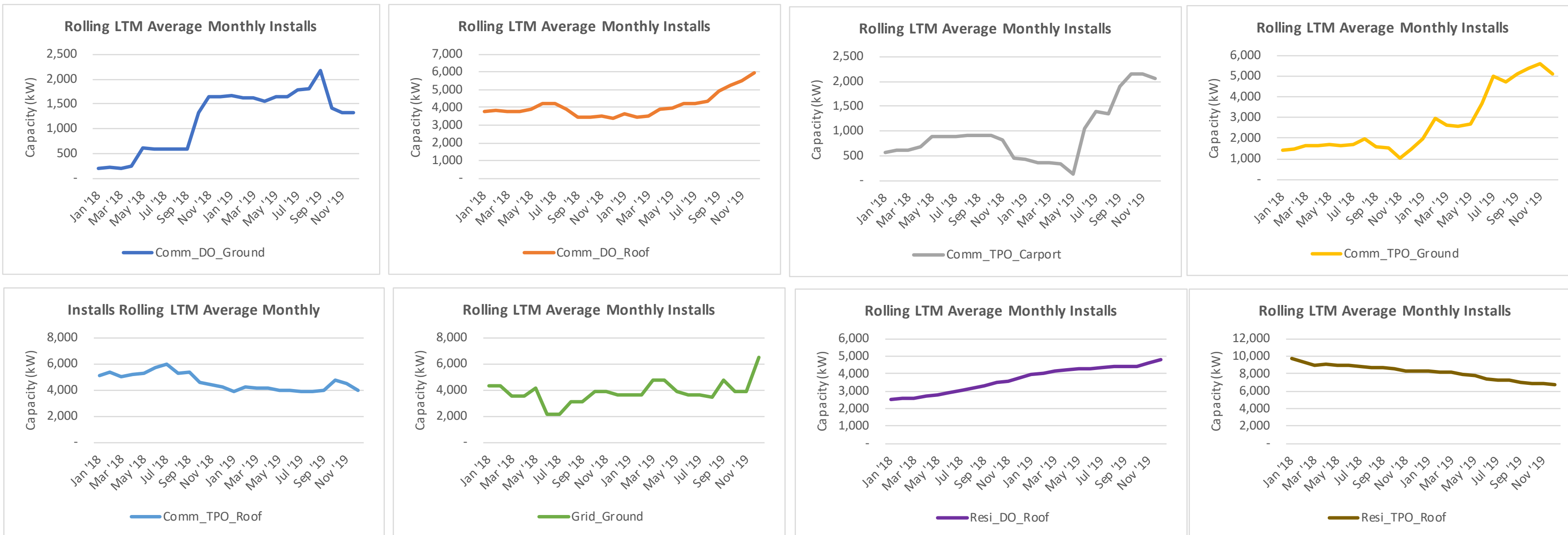
Appendix B. Installed Capacity Growth by Broad SAM Case

Figure 18. Annual Installations



Notes:
Based on an analysis of installed projects in the March 2020 Equipment List.
Graphs y-axes are different scales.

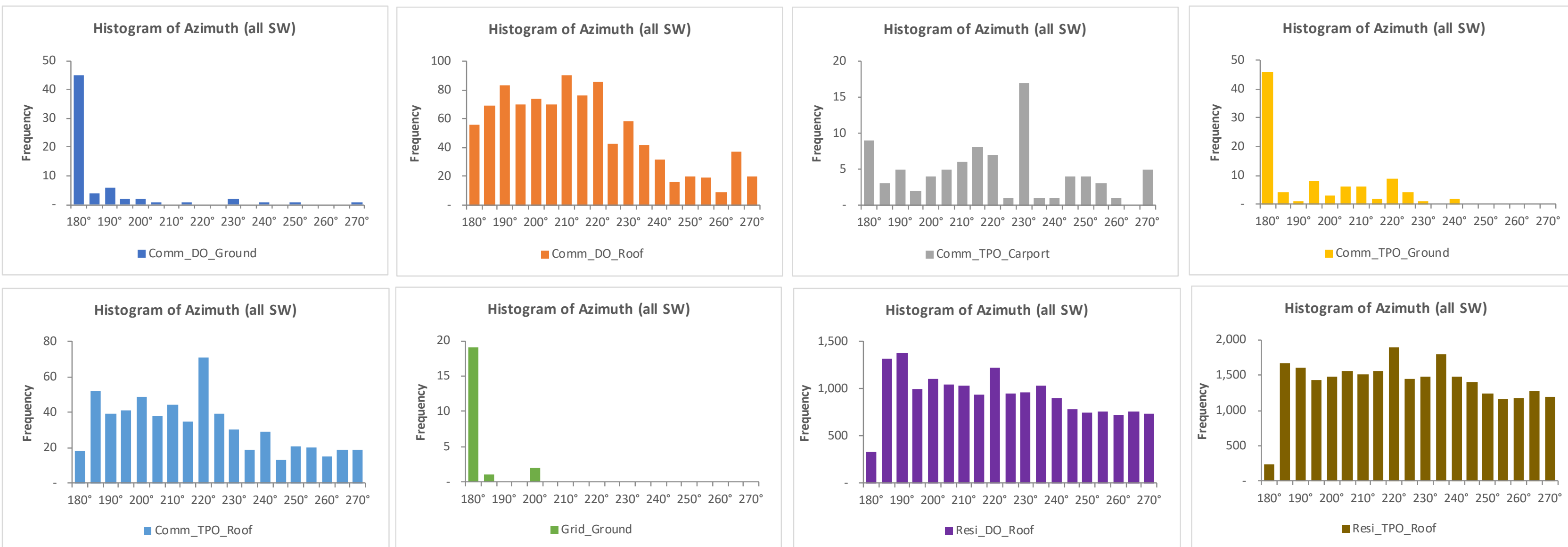
Figure 19. Rolling 12-Month Average Monthly Installations (Jan. 2018-Dec. 2019)



Notes:
January 2018 through December 2019. Based on an analysis of installed projects in the March 2020 Equipment List, using the PTO date as a proxy for installation.
Graphs y-axes are different scales.

Appendix C. Azimuths by Broad SAM Case

Figure 20. Distributions of Adjusted Azimuths



Notes:
Based on an analysis of installed projects in the March 2020 Equipment List.
Note: Azimuths counted only between 90° and 270° and then converted to southwest equivalent, i.e., 180° to 270°.

Appendix D. OpenEI Retail Electricity Prices

Table 39. OpenEI Retail Electricity Prices Via SAM

Customer Service Class	ACE			JCPL			PSEG			RECO		
Residential												
Rate schedule	Residential Service			Residential Service			RS - Residential Service			Residential Service (SC1)		
OpenEI reference file (GUID/URI ref	5e4aad005457a3b37dc0e722			5d5c3d3e5457a33033f1ab35			5d0a5d9d5457a33b46474944			5bc495a35457a349473b43ef		
SAM Energy Rate Chart Rows												
	Period	Tier	Rate ($/kWh)	Period	Tier	Rate ($/kWh)	Period	Tier	Rate ($/kWh)	Period	Tier	Rate ($/kWh)
Row 0	Summer	up to 750 kWh	$ 0.180504	Summer	up to 600 kWh	$ 0.110097	Winter	up to 600 kWh	$ 0.171509	Summer	up to 250 kWh	$ 0.145671
Row 1	Summer	>750 kWh	$ 0.201172	Summer	>600 kWh	$ 0.163957	Winter	>600 kWh	$ 0.171509	Summer	>250 kWh	$ 0.185741
Row 2	Winter	up to 500 kWh	$ 0.182396	Winter	all	$ 0.128354	Summer	up to 600 kWh	$ 0.174467	Winter	all	$ 0.162491
Row 3	Winter	>500 kWh	$ 0.182396				Summer	>600 kWh	$ 0.188134			
Weighted Rates for PPA derivations [1]												
Summer			$ 0.201172			$ 0.163957			$ 0.188134			$ 0.185741
Winter			$ 0.182396			$ 0.128354			$ 0.171509			$ 0.162491
Seasonal weighted rate [2]			$ 0.189906			$ 0.142595			$ 0.178159			$ 0.171791
Commercial												
Rate schedule	MGS Secondary - Three Phase - BGS-RSCP			General Service Secondary (Three Phase			GLP - General Lighting and Power Service			GS - Unmetered Service Secondary Servi		
OpenEI reference file (GUID/URI ref	5e4ab84f5457a3b37dc0e723			5d5c47935457a33033f1ab37			5d0a74865457a33e46474944			5bc4ff775457a38d103b43f2		
SAM Energy Rate Chart Rows												
	Period	Breakpoint	Rate ($/kWh)	Period	Breakpoint	Rate ($/kWh)	Period	Tier	Rate ($/kWh)	Period	Tier	Rate ($/kWh)
Row 0	Summer	n/a	$ 0.155072	Summer	up to 1,000 kwh	$ 0.163186	Winter	n/a	$ 0.065749	Winter	n/a	$ 0.123141
Row 1	Winter	n/a	$ 0.154883	Summer	>1,000 kWh	$ 0.108630	Summer	n/a	$ 0.059926	Summer	n/a	$ 0.132781
Row 2				Winter	up to 1,000 kwh	$ 0.158755						
Row 3				Winter	>1,000 kWh	$ 0.108630						
Weighted Rates for PPA derivations [1]												
Summer			$ 0.155072			$ 0.108630			$ 0.059926			$ 0.132781
Winter			$ 0.154883			$ 0.108630			$ 0.065749			$ 0.123141
Seasonal weighted rate [2]			$ 0.154959			$ 0.108630			$ 0.063420			$ 0.126997

Notes
Source: OpenEI via SAM.
1. Assumes that load substantially exceeds maximum monthly usage breakpoints, so that the higher tier in each season is used for weightings.
2. Seasonal weightings below based on seasonal breakdown (Summer: June-Sept; Winter: Oct-May) and SEPs derived separately:

Summer	40%
Winter	60%

Appendix E. SAM Resi_DO Payback Period Components

Table 40. Comparison of Resi_DO_Roof Payback Period Components

Payback Period Components	10-Year Payback Period	7-Year Payback Period	Difference	Comments
Value of electricity savings	18,656	13,177	(5,479)	Three fewer years of savings
Add: state/federal tax savings	6,030	2,773	(3,256)	Higher taxes from higher PBI revenue
Add: PBI income	7,998	15,461	7,463	Three fewer years of PBI but higher rate
Less: Debt interest tax impact	1,962	1,607	(355)	
Less: Operating expenses	3,122	2,204	(917)	Three fewer years of opex
Total for payback period calculation	**27,600**	**27,600**	-	

Appendix F.Large C&I Retail Electricity Prices

Table 41. ACE Large C&I Tariff

	Large C&I (Annual General Service (AGS) - Secondary)				
Charge [1]	**Sheet No.**	**Effective Date**	**Tier**	**Winter Charge ($/kWh)**	**Summer Charge ($/kWh)**
BGS Energy Charges					
Non-tiered	60a [2]	6/1/2020		$ 0.034847	$ 0.031572
Distribution					
Non-tiered	*n/a ($/kW charge)*				
BGS Transmission					
Non-tiered	*n/a ($/kW charge)*				
Adjustments					
Transition Bond Charge	56	10/1/2019		$ 0.002400	$ 0.002400
Market Transition Charge Tax	56	10/1/2019		$ 0.001028	$ 0.001028
Non-Utility Generation	57	6/1/2020		$ 0.012254	$ 0.012254
Clean Energy Program	58	11/9/2019		$ 0.003502	$ 0.003502
Uncollectible Accounts	58	11/9/2019		$ 0.000243	$ 0.000243
Universal Service Fund	58	11/9/2019		$ 0.001332	$ 0.001332
Lifeline	58	11/9/2019		$ 0.000755	$ 0.000755
Ancillary Service Charge	60a	6/1/2020		$ 0.006753	$ 0.006753
BGS Reconciliation	60a	6/1/2020		$ (0.005860)	$ (0.005860)
CIEP Standby Fee	60b	6/1/2020		$ 0.000160	$ 0.000160
Transmission Enhancement (TEC)	60b	6/1/2020		$ 0.000783	$ 0.000783
RGGI Recovery Charge	64	6/1/2020		$ 0.000334	$ 0.000334
Defered Income Tax Credit	66	4/1/2019		$ (0.002785)	$ (0.002785)
Zero Emission Certificate Recovery Charge	67	4/18/2019		$ 0.004265	$ 0.004265
Total adjustments				$ 0.025164	$ 0.025164
Total kWh charges					
Non-tiered				**$ 0.060011**	**$ 0.056736**

Source: Atlantic City Electric Company Tariff for Electric Service,
Effective Date 4/1/19 (with updates through 6/1/2020).

Notes:
Winter: October through May; Summer: June through September
1. Including New Jersey Sales and Use Tax.
2. Derived from tariff calculation and data from PJM (see text of report for further discussion).

Table 42. ACE Large C&I Energy Charge Derivation

Steps to Derive BGS Energy Charge	Units	Calculations	Results by Season: Winter	Results by Season: Summer
Mean Residual Metered Load Aggregate LMP ($/MWh)	$/MWh	A given	$ 24.70	$ 21.74
Mean Residual Metered Load Aggregate LMP ($/kWh)	$/kWh	B=A/1,000	$ 0.0247	$ 0.0217
Add: Ancillary Services	$/kWh	C given	$ 0.0068	0.00675
Subtotal	$/kWh	D=B+C	$ 0.0314	$ 0.0285
Multiply by: Losses Multiplier [1]	index	E given [1]	1.04700	1.04700
Multiply by: Sales and Use Tax Multiplier	index	F given	1.05833	1.05833
BGS Energy Charge	$/kWh	G=D*E*F	$ 0.0348	$ 0.0316

Sources: Calculation per ACE Tariff for Service (Sheet 60a); Residual Metered Load Aggregate LMP data for 2019 from PJM site: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.

Notes
Seasons per utility schedule: Winter is October through May, Summer is June through September.
1. Used losses from PSEG tariff: 5.8327%

Table 43. JCPL Large C&I Tariff

Charge [1]	Large C&I (GP - General Service Primary) Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)
BGS Energy Charges				
Non-tiered	37 [2]	6/1/2020	$ 0.034573	$ 0.031005
Distribution				
Non-tiered	17	6/1/2020	$ 0.003358	$ 0.003358
BGS Transmission				
Non-tiered	17	6/1/2020	$ 0.005721	$ 0.005721
Adjustments				
TEC Surcharge	38	6/1/2020	$ 0.002784	$ 0.002784
BGS Reconciliation	38	6/1/2020	$ (0.000172)	$ (0.000172)
CIEP Standby Fee	39	6/1/2019	$ 0.000160	$ 0.000160
Non-Utility Generation Charge	40A	1/1/2020	$ 0.000109	$ 0.000109
Societal Benefits Charge	43	6/1/2020	$ 0.007013	$ 0.007013
RGGI Recovery Charge	58	1/1/2020	$ -	$ -
Zero Emission Certificate Recovery Charge	60	4/18/2019	$ 0.004265	$ 0.004265
Tax Act Adjustment (TAA)	61	5/15/2019	$ (0.002936)	$ (0.002936)
Reliability Plus	n/a ($/kW charge)			
Total adjustments			$ 0.011223	$ 0.011223
Total kWh charges				
Non-tiered			**$ 0.054875**	**$ 0.051307**

Source: Jersey Central Power & Light Company Tariff for Service, Part III Service Classifications and Riders, Effective Date 1/1/2017 (with updates through 6/1/2020).

Notes:
Winter: October through May; Summer: June through September
1. Including New Jersey Sales and Use Tax.
2. Derived from tariff calculation and data from PJM (see below).

Table 44. JCPL Large C&I Energy Charge Derivation

Steps to Derive BGS Energy Charge	Units	Calculations	Results by Season: Winter	Summer
Mean Residual Metered Load Aggregate LMP ($/MWh)	*$/MWh*	A given	$ 24.97	$ 21.77
Mean Residual Metered Load Aggregate LMP ($/kWh)	*$/kWh*	B=A/1,000	$ 0.0250	$ 0.0218
Add: Ancillary Services	*$/kWh*	C given	$ 0.0060	$ 0.0060
Subtotal	*$/kWh*	D=B+C	$ 0.0310	$ 0.0278
Multiply by: Losses Multiplier for GP	*index*	E given	1.04700	1.04700
Multiply by: Sales and Use Tax Multiplier	*index*	F given	1.06625	1.06625
BGS Energy Charge	*$/kWh*	G=D*E*F	$ 0.0346	$ 0.0310

Notes
Sources: Calculation per JCP&L Tariff for Service (Sheet 37); Residual Metered Load Aggregate LMP data for 2019 from PJM site: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.
Blue values are hard-coded inputs; black numbers are calculations.
Seasons per utility schedule: Winter is October through May, Summer is June through September.

Table 45. PSEG Large C&I Tariff

Charge [1]	Sheet No.	Effective Date	Tier	Winter Charge ($/kWh)	Summer Charge ($/kWh)
	Large C&I (LPL - Large Power and Lighting)				
BGS Energy Charges					
Non-tiered	82 [2]	6/1/2020		$ 0.035306	$ 0.031331
Distribution					
Non-tiered	142	10/1/2019		$ -	$ -
BGS Transmission					
Non-tiered	*n/a ($/kW charge)*				
Adjustments					
Societal Benefits Charge	57	2/1/2020		$ 0.008443	$ 0.008443
Non-Utility Generation Charge	60	6/1/2020		$ 0.000132	$ 0.000132
Zero Emission Certificate Recovery Charge	61	4/18/2019		$ 0.004265	$ 0.004265
Solar Pilot Recovery Charge	64	1/1/2020		$ 0.000149	$ 0.000149
Green Programs Recovery Charge	65	2/1/2020		$ 0.001334	$ 0.001334
Tax Adjustment Credit	69	2/1/2020		$ (0.000947)	$ (0.000947)
C&I Energy Pricing (CIEP) Standby Fee (LPL)	73	11/1/2018		$ 0.000160	$ 0.000160
Total adjustments				$ 0.013536	$ 0.013536
Total kWh charges					
Non-tiered				**$ 0.048842**	**$ 0.044867**

Source: Public Service Electric and Gas Company Tariff for Electric Service, effective 11/1/18 (with updates through 6/1/2020).

Notes:
Winter: October through May; Summer: June through September
1. Including New Jersey Sales and Use Tax.
2. Derived from tariff calculation and data from PJM (see below).

Table 46. PSEG Large C&I Energy Charge Derivation

Steps to Derive BGS Energy Charge	Units	Calculations	Results by Season: Winter	Results by Season: Summer
Mean Residual Metered Load Aggregate LMP ($/MWh)	*$/MWh*	A given	$ 25.29	$ 21.77
Mean Residual Metered Load Aggregate LMP ($/kWh)	*$/kWh*	B=A/1,000	$ 0.0253	$ 0.0218
Add: Ancillary Services	*$/kWh*	C given	$ 0.0060	$ 0.0060
Subtotal	*$/kWh*	D=B+C	$ 0.0313	$ 0.0278
Multiply by: Losses Multiplier for LPL [1]	*index*	E given	1.05833	1.05833
Multiply by: Sales and Use Tax Multiplier	*index*	F given	1.06625	1.06625
BGS Energy Charge	*$/kWh*	G=D*E*F	$ 0.0353	$ 0.0313

Notes
Sources: Calculation per PSEG Tariff for Service (Sheet 82); Residual Metered Load Aggregate LMP data for 2019 from PJM site: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.
Seasons per utility schedule: Winter is October through May, Summer is June through September.
1. Nominal electric losses and unaccounted for percentages: 5.8327%

Table 47. RECO Large C&I Tariff

Charge [1]	Leaf No.	Effective Date	Tier	Large C&I (Large General) Winter Charge ($/kWh)	Large C&I (Large General) Summer Charge ($/kWh)
BGS Energy Charges					
Non-tiered	52 [2]	6/1/2019		$ 0.036025	$ 0.032361
Distribution					
Tier 1	123 [3]	2/1/2020	On-Peak	$ 0.017700	$ 0.017700
Tier 2	123 [3]	2/1/2020	Off-Peak	$ 0.013250	$ 0.013250
BGS Transmission					
Tier 1	124 [3]	2/1/2020	On-Peak	$ 0.004040	$ 0.004040
Tier 2	124 [3]	2/1/2020	Off-Peak	$ 0.004040	$ 0.004040
Adjustments					
BGS Reconciliation	54	6/1/2020		$ (0.014760)	$ (0.014760)
CIEP Standby Fee	55	1/1/2018		$ 0.000160	$ 0.000160
Societal Benefits Charge (SBC)	56	11/1/2019		$ 0.005669	$ 0.005669
RGGI Recovery Charge	58	12/30/2019		$ 0.002068	$ 0.002068
Securitization Charges	59	6/1/2019		$ -	$ -
Temporary Tax Act Credit	60	7/1/2018		$ (0.002350)	$ (0.002350)
Zero Emission Certificate Recovery Charge	61	4/18/2019		$ 0.004265	$ 0.004265
Total adjustments				$ (0.004948)	$ (0.004948)
Total kWh charges					
Non-tiered			**Weighted [4]**	**$ 0.050831**	**$ 0.047032**
Tier 1			**On-Peak**	**$ 0.052817**	**$ 0.049153**
Tier 2			**Off-Peak**	**$ 0.048367**	**$ 0.044703**

Source: Rockland Electric Company Schedule for Electric Service, effective 5/17/2010 (with updates through February 2020).

Notes:
Winter: October through May; Summer: June through September
1. Including New Jersey Sales and Use Tax.
2. Derived from tariff calculation and data from PJM (see below).
3. Based on four periods:
   Period I is 10a-10p weekdays, June through September (assumed to be Summer, On-peak)
   Period II is 10p-10a weekdays and all hours weekends, June-Sept. (assumed to be Summer, Off-peak)
   Period III is 10a-10p weekdays, Oct-May (assumed to be Winter, On-peak)
   Period IV is 10p-10a weekdays and all hours weekends, Oct-May (assumed to be Winter, Off-peak)
4. Weighted On-Peak and Off-Peak periods by solar production within seasons to consolidate into seasonal periods.

Table 48. RECO Large C&I Energy Charge Derivation

			Results by Season	
Steps to Derive BGS Energy Charge	Units	Calculations	Winter	Summer
Mean Residual Metered Load Aggregate LMP ($/MWh)	$/MWh	A given	$ 25.52	$ 22.28
Mean Residual Metered Load Aggregate LMP ($/kWh)	$/kWh	B=A/1,000	$ 0.0255	$ 0.0223
Add: Ancillary Services	$/kWh	C given	$ 0.0064	$ 0.0064
Subtotal	$/kWh	D=B+C	$ 0.0319	$ 0.0287
Multiply by: Losses Multiplier [1]	index	E given	1.05833	1.05833
Multiply by: Sales and Use Tax Multiplier	index	F given	1.06625	1.06625
BGS Energy Charge	$/kWh	G=D*E*F	$ 0.0360	$ 0.0324

Notes

Sources: Calculation per RECO Tariff for Service (Leaf 52); Residual Metered Load Aggregate LMP data for 2019 from PJM site: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.

Seasons per utility schedule: Winter is October through May, Summer is June through September.

1. Used losses from PSEG tariff: 5.8327%

Appendix G. Community Solar Rates

Table 49. ACE Community Solar Rate

	CS Bill Credits for Residential				CS Bill Credits for Commercial (Monthly General Service (MGS) - Secondary)			
Charge [1]	Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)	Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)
BGS Energy Charges								
Non-tiered					60	6/1/2020	$ 0.066737	$ 0.067391
Tier 1	60	6/1/2020	$ 0.075164	$ 0.064945				
Tier 2	60	6/1/2020	$ 0.075164	$ 0.074380				
Distribution								
Non-tiered					11	4/1/2020	$ 0.054093	$ 0.048325
Tier 1	5	4/1/2020	$ 0.061731	$ 0.056524				
Tier 2	5	4/1/2020	$ 0.071809	$ 0.058795				
BGS Transmission								
Non-tiered	5	4/1/2020	0.01915592	0.01915592	11	4/1/2020	*demand-based*	
Adjustments								
Transition Bond Charge	56	10/1/2019	*not applied*		56	10/1/2019	*not applied*	
Market Transition Charge Tax	56	10/1/2019	*not applied*		56	10/1/2019	*not applied*	
Non-Utility Generation	57	6/1/2020	*not applied*		57	6/1/2020	*not applied*	
Clean Energy Program	58	11/9/2019	*not applied*		58	11/9/2019	*not applied*	
Uncollectible Accounts	58	11/9/2019	*not applied*		58	11/9/2019	*not applied*	
Univesal Service Fund	58	11/9/2019	*not applied*		58	11/9/2019	*not applied*	
Lifeline	58	11/9/2019	*not applied*		58	11/9/2019	*not applied*	
BGS Reconciliation	60a	6/1/2020	$ 0.003089	$ 0.003089	60a	6/1/2020	$ 0.003089	$ 0.003089
Transmission Enhancement (TEC)	60b	6/1/2020	$ 0.001269	$ 0.001269	60b	6/1/2020	$ 0.001006	$ 0.001006
RGGI Recovery Charge	64	6/1/2020	$ 0.000313	$ 0.000313	64	6/1/2020	$ 0.000313	$ 0.000313
Defered Income Tax Credit	66	4/1/2019	$ (0.004581)	$ (0.004581)	66	4/1/2019	$ (0.004491)	$ (0.004491)
Zero Emission Certificate Recovery Charge	67	4/18/2019	*not applied*		67	4/18/2019	*not applied*	
Total adjustments			$ 0.000091	$ 0.000091			$ (0.000083)	$ (0.000083)
Total kWh charges								
Non-tiered							$ 0.120747	$ 0.115634
Tier 1			$ 0.156143	$ 0.140717				
Tier 2			$ 0.166220	$ 0.152422				
Seasonal weighting			60%	40%			60%	40%
Annual weighted credit				**$ 0.160701**				**$ 0.118702**

Derivation of single, weighted credit	
Assumed breakdown of subscribers, i.e., tariff classes:	
Residential	60%
Commercial	40%
Weighted credit	**$ 0.143901**

Sources: ACE Community Solar Bill Credit Calculations, updated with rates from ACE Tariff for Electric Service Effective Date 4/1/19 (with updates through 6/1/2020).

Notes:
Winter: October through May; Summer: June through September
1. Before New Jersey Sales and Use Tax: 6.625%

Table 50. JCPL Community Solar Rate

	CS Bill Credits for Residential				CS Bill Credits for Commercial (General Service (GS))			
Charge [1]	Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)	Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)
BGS Energy Charges								
Tier 1	35	6/1/2020	$ 0.079047	$ 0.069076	60	6/1/2020	$ 0.071053	$ 0.071950
Tier 2 [2]	35	6/1/2020	$ 0.079047	$ 0.077728	60	6/1/2020	$ 0.071053	$ 0.071950
Distribution								
Tier 1	3	6/1/2020	$ 0.023211	$ 0.014169	11	6/1/2020	$ 0.051459	$ 0.055615
Tier 2	3	6/1/2020	$ 0.023211	$ 0.056031	11	6/1/2020	$ 0.004448	$ 0.004448
BGS Transmission								
Non-tiered	3	6/1/2020	$ 0.008214	$ 0.008214	3	6/1/2020	$ 0.008214	$ 0.008214
Adjustments								
Transition Bond Charge			*not applied*				*not applied*	
Market Transition Charge Tax			*not applied*				*not applied*	
Non-Utility Generation			*not applied*				*not applied*	
Clean Energy Program			*not applied*				*not applied*	
Uncollectible Accounts			*not applied*				*not applied*	
Univesal Service Fund			*not applied*				*not applied*	
Lifeline			*not applied*				*not applied*	
BGS Reconciliation	36	6/1/2020	$ (0.000955)	$ (0.000955)	36	6/1/2020	$ (0.000955)	$ (0.000955)
Transmission Enhancement (TEC)			*not applied*				*not applied*	
RGGI Recovery Charge	58	6/1/2020	$ -	$ -	58	6/1/2020	$ -	$ -
SREC Charge	58	6/1/2020	$ -	$ -	58	6/1/2020	$ -	$ -
Tax Act Adjustment	61	6/1/2020	$ (0.005992)	$ (0.005992)	61	6/1/2020	$ (0.004798)	$ (0.004798)
Defered Income Tax Credit			*not applied*				*not applied*	
Zero Emission Certificate Recovery Charge			*not applied*				*not applied*	
Total adjustments			$ (0.006947)	$ (0.006947)			$ (0.005753)	$ (0.005753)
Total kWh charges								
Tier 1			$ 0.103525	$ 0.084512			$ 0.124973	$ 0.130026
Tier 2			$ 0.103525	$ 0.135026			$ 0.077962	$ 0.078860
Seasonal weighting			60%	40%			60%	40%
Annual weighted credit				**$ 0.116125**				**$ 0.078321**

Derivation of single, weighted credit
Assumed breakdown of subscribers, i.e., tariff classes:

Residential	60%
Commercial	40%
Weighted credit	**$ 0.101004**

Sources: JCP&L Community Solar Bill Credit Calculations, updated with rates from JCP&L Tariff for Electric Service Effective Date 6/1/2020

Notes:
Winter: October through May; Summer: June through September
1. Before New Jersey Sales and Use Tax: 6.625%
2.JCP&L's tariff features break points of 600 kWh for the residential rate and 1,000 kWh for the General Service rate

Table 51. PSEG Community Solar Rate

	CS Bill Credits for Residential				CS Bill Credits for Commercial (General Light and Power (GL&P))			
Charge [1]	Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)	Sheet No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)
BGS Energy Charges								
Non-tiered					76	6/1/2020	$ 0.049686	$ 0.047808
Tier 1	75	6/1/2020	$ 0.126003	$ 0.124164				
Tier 2 [2]	75	6/1/2020	$ 0.126003	$ 0.133120				
Distribution								
Non-tiered					129	10/1/2019	$ 0.007706	$ 0.003019
Tier 1	93	11/1/2019	$ 0.033344	$ 0.038220				
Tier 2	93	11/1/2019	$ 0.033344	$ 0.042041				
BGS Transmission								
Non-tiered			*not applied*				*not applied*	
Adjustments								
Transition Bond Charge			*not applied*				*not applied*	
Market Transition Charge Tax			*not applied*				*not applied*	
Non-Utility Generation	60	6/1/2020	$ 0.000068	$ 0.000068	60	6/1/2020	$ 0.000124	$ 0.000124
Clean Energy Program			*not applied*				*not applied*	
Uncollectible Accounts			*not applied*				*not applied*	
Univesal Service Fund			*not applied*				*not applied*	
Lifeline			*not applied*				*not applied*	
BGS Reconciliation			*not applied*				*not applied*	
Transmission Enhancement (TEC)			*not applied*				*not applied*	
RGGI Recovery Charge			*not applied*				*not applied*	
SREC Charge	64	1/1/2020	$ 0.000140	$ 0.000140	64	1/1/2020	$ 0.000140	$ 0.000140
Tax Act Adjustment	69	2/1/2020	$ (0.005275)	$ (0.005275)	69	2/1/2020	$ (0.000888)	$ (0.000888)
Green Program Recovery Charge	65	2/1/2020	$ 0.001251	$ 0.001251	65	2/1/2020	$ 0.001251	$ 0.001251
Defered Income Tax Credit			*not applied*				*not applied*	
Zero Emission Certificate Recovery Charge			*not applied*				*not applied*	
Total adjustments			$ (0.003816)	$ (0.003816)			$ 0.000626	$ 0.000626
Total kWh charges								
Non-tiered							$ 0.058019	$ 0.051453
Tier 1			$ 0.155531	$ 0.158568				
Tier 2			$ 0.155531	$ 0.171344				
Seasonal weighting			60%	40%			60%	40%
Annual weighted credit				**$ 0.161856**				**$ 0.055393**

Derivation of single, weighted credit
Assumed breakdown of subscribers, i.e., tariff classes:

Residential	60%
Commercial	40%
Weighted credit	**$ 0.119271**

Sources: PSEG Community Solar Bill Credit Calculations, updated with rates from PSEG Tariff for Electric Service.
Effective Date 6/1/2020

Notes:
Winter: October through May; Summer: June through September
1. Before New Jersey Sales and Use Tax: 6.625%
2.PSEG's tariff features break points of 600 kWh for residential systems

Table 52. RECO Community Solar Rate

Charge [1]	CS Bill Credits for Residential (SC 1): Leaf No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)	CS Bill Credits for Commercial (SC 2): Leaf No.	Effective Date	Winter Charge ($/kWh)	Summer Charge ($/kWh)
BGS Energy Charges								
Non-tiered					50	6/1/2019	$ 0.049388	$ 0.047231
Tier 1	50	6/1/2019	$ 0.076202	$ 0.056038				
Tier 2	50	6/1/2019	$ 0.076202	$ 0.093487				
Distribution								
Non-tiered					88	2/1/2020	$ 0.032647	$ 0.036033
Tier 1	82	2/1/2020	$ 0.050082	$ 0.050082				
Tier 2	82	2/1/2020	$ 0.050082	$ 0.063072				
BGS Transmission								
Non-tiered					83	2/1/2020	$ 0.014209	$ 0.014209
Tier 1	83	2/1/2020	$ 0.014209	$ 0.014209				
Tier 2	83	2/1/2020	$ 0.014209	$ 0.014209				
Adjustments								
BGS Reconciliation	54	3/1/2020	$ (0.013018)	$ (0.013018)	54	3/1/2020	$ (0.013843)	$ (0.013843)
Transmission Surcharge	83	2/1/2020	$ 0.011920	$ 0.011920	83	2/1/2020	$ 0.011920	$ 0.011920
RGGI Recovery Charge	58	12/30/2019	$ 0.001819	$ 0.001819	58	12/30/2019	$ 0.001819	$ 0.001819
Temporary Tax Act Credit	60	7/1/2018	$ (0.002204)	$ (0.002204)	60	7/1/2018	$ (0.002204)	$ (0.002204)
Zero Emission Certificate Recovery Charge			*not applied*				*not applied*	
Total adjustments			$ (0.001482)	$ (0.001482)			$ (0.002307)	$ (0.002307)
Total kWh charges								
Non-tiered							$ 0.093937	$ 0.095165
Tier 1			$ 0.139011	$ 0.118846				
Tier 2			$ 0.139011	$ 0.169285				
Seasonal weighting			60%	40%			60%	40%
Annual weighted credit				**$ 0.151120**				**$ 0.094428**

Derivation of single, weighted credit

Assumed breakdown of subscribers, i.e., tariff classes:	
Residential	60%
Commercial	40%
Weighted credit	**$ 0.128443**

Sources: RECO Community Solar Bill Credit Calculations, updated with rates from the EDC's Schedule for Electric Service, effective 5/17/2010 (with updates through February 2020).

Notes:
Winter: October through May; Summer: June through September
1. Before New Jersey Sales and Use Tax: 6.625%