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STATE OF NEW JERSEY

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NOTICE[1]

New Jersey Solar Transition

Revised 2019/2020 Transition Incentive Staff Straw Proposal

and Modeling Addendum -- UPDATE

Pursuant to the Clean Energy Act of 2018 ("Act"), the Board of Public Utilities ("Board") has undertaken the 2019/2020 Solar Transition. The Act requires the Board to complete a study that evaluates how to replace or modify the SREC program to encourage the continued efficient and orderly development of solar renewable energy generating resources throughout the State. The Act also requires that the current SREC program be closed to new applications upon the State's attainment of 5.1% of kilowatt hours sold in the State from solar electric generation facilities. In implementation of the Act, the Board has engaged Cadmus (and their subcontractor, Sustainable Energy Advantage, collectively the "Consultant") to conduct modeling and analysis for the Solar Transition. Board Staff has worked with the Consultant and stakeholders throughout this process, and thanks all stakeholders for their active engagement at meetings and for their comments.

Board Staff provides the attached revision of the Consultant's analysis, which identifies several additional changes to the Consultant's modeling results. In the interest of transparency, Staff will permit parties to file additional comments on the revised Consultant modeling efforts. While all comments will be considered, Staff urges parties to avoid reiterating points previously made, and to instead focus on positions that may change in light of these updated Consultant modeling results.

Staff notes that while it intends to consider the modeling results provided by its Consultant, Staff does not consider the Consultant's findings binding on Staff and does not intend to solely rely on the Consultant's findings. In developing a revised recommendation on factorization levels, Staff notes that it intends to fully consider its own internal policy views, the experiential data in the

[1]Not a Paid Legal Advertisement

various comments received to date, and the importance of the solar industry to the State of New Jersey in recommending appropriate Solar Transition Incentive levels to the Board.

Staff is therefore also publishing an updated Staff Straw Proposal, which reflects Staff's consideration of the Consultant's most recent modeling results, verbal comments made by stakeholders in meetings, and written comments submitted to the Board by October 18, 2019.

For convenience, changes to the Staff Straw Proposal compared to the version issued on October 3, 2019, are identified via a yellow highlight.

All comments must be received on or before **5:00 p.m. on November 27, 2019** in order to be considered. Written comments must be submitted to Aida Camacho-Welch, Secretary, New Jersey Board of Public Utilities, Post Office Box 350, Trenton, New Jersey, 08625. Written comments may also be submitted electronically to solar.transitions@bpu.nj.gov in PDF or Microsoft Word format. Please note that these comments may be considered "public documents" for purposes of the State's Open Public Records Act. Stakeholders may identify information that they wish to keep confidential by submitting them in accordance with the confidentiality procedures set forth in N.J.A.C. 14:1-12.3.

Aida Camacho-Welch

Aida Camacho-Welch
Board Secretary

Dated: November 14, 2019

Revised 2019/2020 Transition Incentive Staff Straw Proposal

("Revised Staff Straw Proposal" or "Revised TI Straw")

In the December 2018 Straw Proposal and the April 2019 Notice, Staff indicated that it is considering recommending that the Solar Transition be addressed in three phases: 1) the closure of the Legacy Solar Renewable Energy Certificates ("SREC") market to new registrations upon the attainment of 5.1% of the energy sold in New Jersey being generated from solar facilities connected to the distribution system;[2] 2) the Transition Incentive, which would be available to projects in the SREC Registration Program ("SRP") pipeline but having not yet achieved commercial operation at the time the 5.1% Milestone is attained; and 3) the Successor Program, which would be developed for all projects not in the SRP pipeline at the time the 5.1% Milestone is attained.

This Revised Transition Straw Proposal is intended to serve as a basis for discussion with stakeholders of potential options for the Transition Incentive. It does not serve as an indication of the Board's position or decisions. Staff has based the following proposal upon the analysis performed by Cadmus and Sustainable Energy Advantage, the Solar Transition Consultant retained by Board Staff. The report, titled "<u>New Jersey Transition Incentive Supporting Analysis & Recommendations</u>" and prepared by the Solar Transition Consultant, as well as its Modeling Addendum are attached to this Straw Proposal.

<u>Proposal for the Structure of the Transition Incentive</u>

Staff proposes that projects eligible for the Transition Incentive would generate Transition Renewable Energy Certificates ("TRECs"). TRECs would be used by the identified Compliance Entities to satisfy a compliance obligation tied to a new Transition Incentive Renewable Portfolio Standard ("TI-RPS"), which would exist in parallel to, and completely separate from, the existing Solar RPS for Legacy SRECs. The TI-RPS would be a carve-out of the current Class I RPS requirement.

The incentive would be structured as a factorized renewable energy certificate, which is designed to provide solar producers a financial incentive tied to the estimated costs of building solar facilities and revenue expectations under basic retail rate tariffs or wholesale market prices for various installation types. In each case, the goal of the factorization program is to ensure that ratepayers are providing the minimum necessary financial incentive to develop diverse types of projects, consistent with maintaining a healthy solar industry in New Jersey. The value of each TREC could either be set in a TREC trading market, comparable to the existing SREC market, or could simply be set by a Board order (see "Valuing of a TREC Options" section below).

<u>Eligible Project Options</u>

Option 1: Staff would propose that projects eligible for the incentive would be those that remain in the SREC SRP queue at the time that the Board determines that NJ's retail electricity market

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[2] I/M/O N.J.A.C. 14:8-2.4 Amendments to the Renewable Portfolio Standard Rules on Closure of the SREC Registration Program Pursuant to P.<u>L.</u> 2018, <u>c.</u> 17. (Rule Proposal).

has attained the 5.1% milestone. Eligible projects would therefore be those that: 1) filed a complete SRP Registration or received conditional certification from the Board after October 29, 2018, *and* 2) have not commenced commercial operation upon the Board's determination that the 5.1% Milestone has been attained.

Option 2: An alternative strategy would be to close the SREC Registration Program to new registrants and immediately initiate a Transition Incentive registration pipeline. The Transition Incentive program would cover both the eligible projects registered in the SRP that remain under development as well as any new projects registered in the Transition Incentive program at the time the 5.1% Milestone is attained. Staff proposes that this could be accomplished by creating new incentive registration processes and an associated pipeline which would ultimately be merged with the projects left in the SRP at the time of 5.1% milestone attainment. This alternative approach would be intended to give additional certainty to developers seeking to bring new projects online prior to decisions about the Successor Program. This approach could also potentially alleviate pressure on the existing SREC registration program and the EDC interconnection infrastructure from projects rushing to meet the 5.1% milestone. Under this alternative, enrollment in a new registration process could be required of all new solar incentive applicants going forward. Projects in the Transition Incentive pipeline would be joined by the un-commissioned projects that remain in the SRP pipeline at the 5.1% milestone to form a new Transition pipeline.[3]

<u>Mechanism for Creation of TRECs</u>

Staff proposes that a TREC would be created based upon metered generation supplied to PJM-EIS GATS ("GATS") by the owners of eligible facilities or their agents. GATS will create one TREC for each megawatt hour ("MWh") of energy produced from a qualified facility. As discussed in the factorization section below, Staff proposes that each MWh of energy produced from a given facility would be provided a TREC factor depending on the type of facility generating the electricity. In the market-valued approach, TRECs would have a useful life (i.e. must be purchased and retired within) of three years. A fixed price TREC would be redeemable in the year in which the electricity was produced or the following Energy Year. Projects would be eligible to receive TRECs for 15 years ("Qualification Life"); after which time, projects may be eligible for a NJ Class I REC.

<u>Value of a TREC Options</u>

Staff proposes two different ways of valuing each TREC. Under Valuation Option #1, the Board would rely on market forces to set the value of each TREC, comparable to the market used to set the value of SRECs. Under Valuation Option #2, the value of each TREC would be established via Board order.

Under Valuation Option #1, the value would be subject to an Alternative Compliance Payment ("ACP") that serves as a soft cap on the value of TRECs, which Staff proposes be called the Transition Incentive Alternative Compliance Payment ("TI-ACP"). The Solar Transition Consultant

[3] The alternative of enlarging the cohort of projects eligible for the Transition Incentive has not been modeled for cost cap implications. Staff anticipates that a large group of registered projects will increase the risk of cost cap exceedance necessitating a lower incentive for the later Transition Incentive registrants.

has proposed that the TI-ACP schedule would be set such that the TI-ACP for EY21 through EY23 would be set relatively low. This would ensure TREC prices during this time period result in incentive program compliance costs that would greatly increase the probability that the total cost of Legacy and Transition incentives do not exceed the cost caps established by the Clean Energy Act of 2018. After EY23, the TI-ACP would be increased so as to ensure that projects receive the full value of the incentive required to develop a project, as shown in the following chart developed by the Solar Transition Consultant.

Revised Table 1. Base Compensation Schedules to Account for Cost Cap

Scenarios/Sensitivities	Cost Profile & Incentive Term	"Kink" Period			Post-"Kink" Period												
		2021	2022	2023	2024	2025	2026	2027	2029	2030	2031	2032	2033	2034	2035	2036	2037
TI-2a - DO w/SREC Factors	Base Cost - 15 Year	$150	$135	$122	$458	$458	$458	$458	$458	$458	$458	$458	$458	$458	$458	$458	$0
TI-3 - DO w/SREC Factors & Firmed Hedge Option	Base Cost - 15 Year	$65	$65	$65	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$0
TI-4 - Partial Long-Term Hedge	Base Cost - 15 Year	$65	$65	$65	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$0

Valuation Option #1

Under Valuation Option #1, a market-based price setting mechanism, the price for each TREC would be established based upon the supply of available TRECs, the TI-RPS demand, transaction costs, and the TI-ACP. The compliance entity would be required to procure and retire TRECs in proportion to their retail sales according to an annual schedule of demand obligations. The ceiling on the TREC price within a given year would be set by the TI-ACP. The TI-ACP for Scenario/Sensitivity case TI-2a in Table 1 developed by the Solar Transition Consultant is most closely aligned with an RPS compliance obligation reliant upon a competitive market-based price required to ensure efficient procurement and retirement of TRECs.

Additionally, under a market-based approach, Staff would recommend the Board direct the EDCs to serve as a “Buyer of Last Resort” for TRECs that remain unsold after the three year useful life granted to each TREC. A pre-established floor price could be established that ensures a contribution to a return on investment for eligible transition projects. EDCs would retire the TRECs and require the ability to pass along the costs of procurement to ratepayers.

Valuation Option #2

Under Valuation Option #2, a fixed price TREC would be compensated at a fixed payment based upon the Consultant’s modeled scenario in Table 1. “Transition Incentive 3 – Demand Obligation with TREC Factors and Firmed Hedge Option” and elements of a “Transition Incentive 4 – Partial Long Term Hedge” would serve as the benchmark TREC price upon which Project Type factors below would be applied.

Factorization of TRECs

Staff seeks comments on assigning different values to electricity produced by different categories of solar facility, a policy known as "factorization." Factorization is designed to provide differing levels of subsidy support to different types of solar installations with the aim of tailoring the size of the subsidy to the amount of revenue needed by each project type. In other words, one MWh of solar production would produce one TREC with a different value depending on the project.

Based on comments filed prior to October 18, 2019, Staff's policy considerations, as well as the revised analysis by the Solar Transition Consultant, Staff proposes that the following factors be established. Projects would be assigned a factor based on the project type; factors cannot be combined.

Revised Table 2. Project Type Factors Expressed as Multipliers

Project Type	Analysis Vintage	Preferred Siting: Subsection t, Rooftop, and Carport	Community Solar	Ground Mounted (Grid Supply & NM >25 kw)	Net Metered Projects (<=25 kW)
Compliance Factor	Initial	1.0	0.80	0.6	0.2
	Revised	**1.0**	**0.85**	**0.6**	**0.6**

Manually, the SRP team would assign certification numbers to each eligible project in the Transition Incentive pipeline, which would indicate a Project Type Factor, falling into one of four categories.

Factorization, if adopted, would be beneficial because it targets the size of the subsidy to the cost of constructing each type of facility, while also considering the regulatory framework in which each project operates (i.e., the retail or wholesale value of the electricity produced, the net of which is referred to as the Cost of Entry). This has the potential to reduce the total cost of the program to ratepayers, while also providing the opportunity for projects to earn a tailored set of returns. For example, the Consultant estimates that net metered projects under 25 kW and eligible for net metering need a lower additional subsidy because net metering already allows most of these projects to earn a large part of its required financial return via avoiding retail rates or receiving a net metering credit. By contrast, a facility falling into the "preferred siting" category, which includes facilities on landfills and rooftops, not otherwise eligible for net metering, generally require a larger subsidy to be economically viable. The projected economics of Community Solar projects fall somewhere in between, and thus, under a factorization proposal, would receive an intermediate subsidy.

Compliance Entities in the TI-RPS Options

The compliance obligation, or requirement to comply with the TI-RPS, could be assigned in one of two ways:

Compliance Entity Option #1: Third Party Suppliers ("TPSs") and Basic Generation Service providers ("BGS Providers") could be obligated to procure and retire TRECs in proportion to their annual retail sales according to an annual schedule of demand obligations that would track the expected production of the projects eligible for the Transition Incentive.

Compliance Entity Option #2: Alternatively, the compliance obligation could be shifted to the Electric Distribution Companies ("EDCs"). The EDCs would be obligated to procure and retire all TRECs produced by eligible projects at pre-established rates assigned by Board Order.

If Compliance Entity Option #1 is selected, i.e., the compliance obligation is placed on TPS and BGS Providers, Staff suggests that the TREC be a market-based, tradeable instrument with value based upon supply and demand, subject to the ACP and any purchaser of last resort mechanism.

If Compliance Entity Option #2 is selected, i.e., the compliance obligation to purchase TRECs is placed on the EDCs, Staff envisions that the TREC could have a fixed price established by Board order. Fixing the TREC value under Compliance Entity Option #2 and placing the purchase obligation on the EDCs has the considerable benefit of being relatively easy to implement.

Staff's initial sense is that a market-based mechanism such as Compliance Entity Option #1 may be more suitable for the Successor program. However, if Compliance Entity Option #1 is selected for the Transition Incentive, Staff suggests that the implementation of the TI-RPS would be achieved in a manner similar to the existing RPS compliance processes. The TI-RPS (i.e. the compliance obligation) would be expressed as a percentage of retail sales. A schedule of annual demand obligations would be assigned to the retail electricity sales of TPS and BGS Providers and each would be required to annually demonstrate to the Board sufficient retirement of RECs or payment of ACPs. Further, because the size of the pipeline of eligible Transition Incentive projects that eventually reach commercial operation is unknown at the time the Legacy SREC program closes, the compliance obligation would have to be adjusted as projects enter service or leave the pipeline. Staff requests comment on how such a mechanism would work.

Staff envisions that the Board would establish a preliminary estimate of the TI-RPS obligation in January 2020, based upon the then-current size of the SRP pipeline, the anticipated size of the SRP pipeline at the time the 5.1% Milestone is attained, and the anticipated build rate and productivity of projects in the pipeline. The January 2020 preliminary estimate of demand would be published in advance of the February 2020 BGS auction, so as to ensure that the TI-RPS compliance obligation would begin in EY2021 (note that this is solely to facilitate administration of the Transition Incentive; any TRECs generated prior to the beginning of EY2021 would remain fully valid for compliance for the duration of their useful life (see Terms for TREC below). The TI-RPS schedule of annual demand obligations established in January 2020 would increase from EY21 through EY23 to reflect the increased production as TI-eligible projects commence commercial operations during this time period.

Upon attainment of the 5.1% Milestone, the TI-RPS demand obligation or annual schedule of percentage requirements could be adjusted to align with the actual size of the SRP pipeline and associated build rates. Any adjustment would be reflected in the compliance obligation for the following energy year, EY2022.

The Clean Energy Act of 2018 signed on May 23, 2018, increased the solar requirements in the RPS starting on June 1, 2018 and exempted BGS supply under contract at the time of enactment. The Act also required implementation in a competitively neutral manner between TPS and BGS Providers which required the increase avoided by the exemption be placed on non-exempt BGS supply. BGS supply contracts are procured annually for a portion of the default electric supply over a period of three years, 1/3 every year. The increase in RPS requirements avoided through exemption of pre-existing BGS contracts will be transferred to non-exempt BGS supply over the two years following the year covered by the exemption.

The Board would require the EDCs to jointly procure TRECs from all eligible solar electric generation facilities using the PJM-EIS GATS platform. A Board-approved, publicly available, TREC price schedule would assign value to the megawatt hours produced by various project types. EDCs would retire the TRECs and pass on to their ratepayers the costs apportioned to each EDC according to market share of statewide retail electricity served.

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Revised: October 3, 2019
Revised: November 14, 2019

Sustainable Energy Advantage, LLC

CADMUS

Addendum to Transition Incentive Supporting Analysis & Recommendations

November 13, 2019

Prepared for:

New Jersey Board of Public Utilities

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Executive Summary

Since the New Jersey Board of Public Utilities ("BPU") issued its initial straw proposal on August 22, 2019, the Consulting Team (Sustainable Energy Advantage, LLC and Cadmus Group LLC) has made several changes to its modeling assumptions in response to stakeholder feedback, as well as technical model corrections to appropriately determine incentive values, ratepayer costs, and Clean Energy Act Cost Cap impacts. Initial revisions were published as a Modeling Addendum to a revised Staff Straw Proposal on October 3, 2019.[1]

This new revised Modeling Addendum contained herein presents the results of further modeling corrections and sensitivities conducted in October 2019. Additionally, a new Section 5 was added to the Modeling Addendum, in which the Consulting Team provides some analysis and sensitivities conducted in response to comments made by stakeholders prior to October 18, 2019.

The revised Modeling Addendum is comprised of five sections:

- Section 1 introduces the Modeling Addendum and the Consulting Team's engagement in the Solar Transition process.
- Section 2 details the changes made to the model and modeling assumptions since the publication of an initial report on August 22, 2019.
- Section 3 provides the revised analysis results given the modifications identified in Section 2.
- Section 4 describes (i) the Consulting Team's analysis of various policy options for a Transition Incentive and (ii) the Consulting Team's final recommendation.
- The **new Section 5** provides some analysis and sensitivities conducted in response to comments made by stakeholders prior to October 18, 2019.

In summary, the following changes have been made to the model and assumptions since the results were initially published on August 22, 2019:

Upfront Capital Cost Percentiles: While the original analysis set the assumed upfront capital cost for the Low/Base/High Cost cases at the 25th, 37.5th and 50th percentiles of costs as filed via the SREC Registration Program ("SRP") (as of March 31, 2019) the revised analysis assumes Low/Base/High Cost values set at the 30th, 50th, and 70th percentiles, respectively.

Impact: This change increases the assumed incentive gaps and costs of entry for all projects.

Third-Party and Host Ownership Assumptions: While the initial analysis set the third-party ownership ("TPO") and host ownership percentages (which weight the ultimate incentive gap/cost of entry by Incentive Group) using the population of projects currently operating (and submitted through the SRP), the revised analysis assumes an increased host ownership share of projects to mirror the percentage

[1] Available at: https://www.njcleanenergy.com/files/file/Solar Transition/Revised Transition Incentive Straw Proposal 2019-10-03.pdf

currently in the SRP pipeline (the eventual source of all projects eligible for the Transition Incentive ("TI")).

Impact: In tandem with the change to ensure host-owned projects receive the full benefit of the federal Investment Tax Credit ("ITC"), the impact of this change is mixed, but tends to lower the incentive gap/cost of entry values for Incentive Groups assumed to have larger host ownership penetrations.

Year 1 Capacity Factors: The initial analysis undertaken by the Consulting Team solely utilized PVWatts (an analysis tool developed by the National Renewable Energy Laboratory ("NREL") to estimate future solar PV production at a given location), along with factors that would indicate non-ideal siting conditions. The revised analysis, in response to stakeholder feedback, modifies the capacity factor for <=25 kW Incentive Group projects to be an average of PVWatts production under non-ideal siting conditions and back-calculated Year 1 values from a PJM-EIS GATS analysis undertaken for the BPU.

Impact: The impact of the change is to lower the capacity factor and thereby increase the incentive gap/cost of entry for <=25 kW projects.

Investment Tax Credit "Safe Harbor" Approach: For a variety of reasons, the Consulting Team's initial analysis assumed that all projects could maintain their federal Investment Tax Credit ("ITC") value of 30 percent for calendar year 2019 by meeting certain criteria set by the Internal Revenue Service ("IRS"). In response to further research and in response to stakeholder feedback, the revised analysis assumes (i) the 2020 ITC of 26 percent for all <=25 kW projects but (ii) that all other Project Types can "safe harbor" the ITC at 30 percent.

Impact: This change increases incentive gap/cost of entry for <=25 kW projects.

Target After-Tax Equity IRR for <=25 kW Projects: Initially, the Consulting Team assumed that host-owned <=25 kW projects could assume an after-tax equity IRR of between 6.5% and 7.0% for Base Cost projects (a proxy for the longer-term return on the S&P 500). Some solar industry stakeholders, however, suggested that these returns were insufficient to make the investment in solar worthwhile for individuals who were unlikely to be in their homes for a long period of time. At the request of the BPU, the Consulting Team has aligned the assumed after-tax equity IRR for <=25 kW projects to match the 12%-13% assumed for solar projects larger than 25 kW.

Impact: This change increased the incentive gap/cost of entry for the <=25 kW Incentive Group by $30-$35/MWh, depending on the policy case in question.

Inclusion of PPA Discount Factor/Year 1 Capacity Value: The Consulting Team had intended to include an assumption in the model that project owners would pass along a 15 percent discount to offtakers as an enticement to enter into a power purchase agreement ("PPA"). When undertaking a model assumption check in September 2019 in response to a stakeholder question, the Consulting Team realized that the 15 percent discount had not been programmed correctly.

Impact: This change increased incentive gaps/costs of entry by $15-$30/MWh, depending on the Incentive Group in question.

Technical Corrections to Ensure Inclusion of ITC Appropriate Tax Rates for Host Owned Projects: When undertaking model checks in October 2019, the Consulting Team discovered (i) that a programming error inadvertently omitted the impact of the federal ITC for host-owned projects; and (ii) that two small host-owned Project Types had an incorrectly calculated tax rate.

> Impact: These changes have the cumulative effect of lowering the incentive gaps/costs of entry for Incentive Groups with higher penetrations of host ownership (including Building Mounted, <=25 kW, and, to a lesser extent, Preferred Siting) by $15-$40/MWh. The incentive gaps/costs of entry for the other categories (including Ground Mounted, Community Solar and Low- and Moderate-Income) were limited or unchanged, since those categories are assumed to have a very small percentage (or zero percent) host ownership.

Conclusion: Overall, and in light of the risk that the Legacy SREC program's costs could rise very high during the "Kink" period (Energy Years 2021-2024 immediately prior to and following the contraction of the Clean Energy Act Cost Cap from 9% to 7% of the "total paid for electricity" in New Jersey), the Consulting Team maintains its October 2019 recommendation of a Fixed Factorized TREC incentive design, set at Base upfront capital cost levels equivalent to the 50th percentile of costs in the SRP database, and an incentive term of between 15 and 20 years.

1. Introduction

1.1. Transition Incentive Stakeholder Process to Date

On August 22, 2019, Staff in the New Jersey Board of Public Utilities ("BPU") issued a Straw Proposal regarding its 2019/2020 Transition Incentive ("Staff Straw Proposal"). As part of the Staff Straw Proposal, the BPU issued a companion report developed by Sustainable Energy Advantage, LLC and Cadmus, Inc. (collectively, the "Consulting Team") in collaboration with the BPU entitled *New Jersey Transition Incentive Supporting Analysis & Recommendations* (hereafter referred to as "TI Report"). The BPU also issued Appendixes and substantiating spreadsheets to further inform the TI Report. The analysis in the TI Report informed BPU Staff's development of the Staff Straw Proposal.

In the August 22 Staff Straw Proposal, BPU Staff proposed a Transition Incentive intended to be based on the creation and sale of Transition Renewable Energy Credits ("TRECs") with specific TREC Factors intended to 'right-size' the value of a TREC to the actual incentive needs for specific types of distributed solar PV projects. The alternative approaches to valuing the proposed factorized TRECs by BPU Staff include:

- A demand obligation ("DO") <u>without</u> a Buyer of Last Resort in which prices are set entirely by supply and demand for TRECs (analogous to Policy Path TI-2a analyzed in the TI Report);
- A DO <u>with</u> a Buyer of Last Resort, which is assumed to be the electric distribution company in whose territory the project is located. The Buyer of Last Resort would purchase excess unsold TRECs at an agreed-upon fixed price at the end of the useful life of a TREC at the option of market participants (analogous to Policy Path TI-3 analyzed in the TI Report); and
- A purchase program for TRECs at a fixed-payment rate (analogous to Policy Path TI-4 analyzed in the TI Report).

In doing so, BPU Staff eliminated other alternatives examined in the Report, specifically, Policy Paths TI-1a and TI-1b (a DO without either TREC Factors or a Buyer of Last Resort) and Policy Path TI-2b (a DO with TREC Factors that was designed to be "perpetually short" of the obligation in order to provide greater price certainty) from further consideration, as either overly expensive for New Jersey ratepayers or otherwise impractical for the purposes of the TI.

The TI Report reflects analysis undertaken by the Consulting Team over a period from January to July 2019. The assumptions that went into the TI Report (and are reflected in the Staff Straw Proposal) were collected from a mixture of data sources, including:

- SREC Registration Program ("SRP") data collected by the BPU and its contractor TRC;
- A Cost and Technical Potential Survey issued in June 2019 and responded to by a wide array of New Jersey solar stakeholders;

- Market data from other distributed energy markets in the Northeastern United States;
- Market intelligence provided to the Consulting Team throughout a variety of engagements analyzing distributed solar markets and policies in the Northeast, elsewhere in the United States, and a variety of foreign nations; and
- Other industry standard data sources and assumptions.

The main assumptions utilized in the analysis that led to the incentive levels proposed in the Staff Straw Proposal were shared with New Jersey solar stakeholders in presentations by the Consulting Team at two stakeholder workshops in New Brunswick, NJ, on May 2, 2019, and Newark, NJ, on June 14, 2019.

Following the concurrent release of the Staff Straw Proposal and the TI report, the BPU offered multiple opportunities for public stakeholder comment, including:

- A webinar held August 23, 2019, to outline the Straw Proposal; and
- In-person public hearings on August 28, 2019, and September 4, 2019, to take comments on the Straw Proposal.

While the Consulting Team did not present any results during the above public hearings, BPU Staff scheduled a follow-up stakeholder Technical Session with the Consulting Team held on September 6, 2019, in Trenton, NJ, to discuss the assumptions that went into the report that informed the Straw Proposal. At that session, the Consulting Team took additional feedback on its assumptions, particularly those pertaining to the <=25 kW Incentive Group. At the Technical Session, New Jersey solar stakeholders had a further opportunity to raise issues and voice concerns with several of the modeling and analysis assumptions. As a result of discussion of these concerns, BPU Staff and the Consulting Team examined for further consideration some potential adjustments to market and policy input assumptions utilized in producing the proposed TREC Factors in the Straw Proposal. The results of these revised assumptions, as well as a correction of two specific programming errors were published by BPU Staff alongside a revised Staff Straw Proposal on October 3, 2019. A stakeholder meeting was held on October 11, 2019, with the Consulting Team present via webinar to answer questions. Written comments from stakeholders were received until October 18, 2019.

Further review of modeling assumptions has led the Consulting Team to update certain assumptions and correct two additional programming errors. These updated results are published in this revised Modeling Addendum.

1.2. Purpose of Report Addendum

The Consulting Team has strong experience establishing effective incentive levels for renewable energy performance-based incentives. This process requires balancing multiple objectives, including ratepayer cost minimization and project viability, through a transparent stakeholder engagement process that incorporates presentation and review of assumptions and results, consideration of stakeholder feedback, and potential refinement of key policy and market assumptions when merited.[2] This Report Addendum represents the Consulting Team's incorporation of several revised assumptions and modeling corrections intended to enhance the quality of the Consulting Team's TI incentive recommendations.

This revised analysis updates incentive levels, associated costs to ratepayers, and Cost Cap impacts associated with the TI-2a, TI-3 and TI-4 policy types. In addition, we have added four new sensitivities on the TI-4 policy type at the BPU Staff's request. Table 1 below compares the different policy cases analyzed in the initial TI Report and the Report Addendum.

Table 1 – Reference Policy Cases and Sensitivities Analyzed in Consulting Team Initial TI Report and TI Report Addendum

Policy Path	Cost Case	Incentive Term (Years)	Initial TI Report (August 2019)	TI Report Addendum (November 2019)
TI-1a	Base	15	✓	
TI-1b	Base	15	✓	
TI-2a	Base	15	✓	✓
TI-2b	Base	15	✓	
TI-3	Base	15	✓	✓
TI-4	Base	15	✓	✓
TI-2a	Base	20	✓	
TI-4	Base	20		✓
TI-2a	Low	20	✓	
TI-4	Low	20		✓
TI-2a	Base	10	✓	
TI-4	Base	10		✓
TI-2a	High	10	✓	
TI-4	High	10		✓

[2] The Consulting Team has extensive experience with such processes through its prior engagements, particularly the Massachusetts Net Metering and Solar Task Force, as well as nearly 10 years of support for development of Ceiling Prices under the Rhode Island Distributed Generation Standard Contracts (DGSC) and Renewable Energy Growth (REG) programs.

1.3. Summary of Revised Consulting Team Recommendation

As detailed in the balance of this Addendum, given the increased incentive values modeled across all policy cases relative to the (initial) report, the Consulting Team has revised its TI recommendation from a market-based TREC approach with TREC Factors (TI-2a) to a fixed TREC approach (TI-4). However, if the BPU wishes to preserve a market-based approach, we recommend that it utilize a hedged purchase option (TI-3) and consider other steps that would encourage participation in order to mitigate ratepayer costs and the risk of breaching the Cost Cap.

2. Modifications to Initial TI Assumptions

Below, we outline the specific changes to assumptions and modeling corrections undertaken since the initial August 2019 TI Report. In doing so, we describe:

- The Consulting Team's initial approach;
- Concerns with the initial approach raised by solar stakeholders or the Consulting Team after further review;
- The revision to the approach pursued by the Consulting Team at the request of BPU Staff; and
- The impact of the revised approach on incentive gaps and project cost of entry.

2.1. Upfront Capital Cost Percentile Assumptions

- **Initial Consulting Team Approach:** When setting upfront capital cost inputs for the various Incentive Groups, the Consulting Team utilized data from the New Jersey SRP to set a *base value* based on the size of the system. In addition, for various specialty Project Types (e.g., Community Solar, Low- and Moderate-Income ("LMI"), Landfill/Brownfield, Carport, and others) that are not clearly marked in the SRP data, the Consulting Team also developed installed cost $/kW to account for the expected incremental costs of such projects relative to a similarly-situated ground mounted or building mounted project in the same size category.[3] Costs from the SRP data vary, and within each Project Type there exists a distribution with a mean and a variance about that mean. In consultation with BPU Staff, the Consulting Team initially selected percentiles within these distributions for the Low, Base, and High installed cost values at the 25th, 37.5th and 50th percentile. These values were selected in order to mitigate risks of overstatement of self-reported installation costs, mitigate risks of breaching the Cost Cap, mitigate ratepayer impacts, and to promote cost-efficient projects. These percentile choices were shared with stakeholders at Stakeholder Workshop #2 in Newark, NJ on June 14, 2019, and published on the BPU Office of Clean Energy's website.
- **Concerns Raised with Initial Consulting Team Approach:** At the September 6, 2019, Technical Session, the Consulting Team heard from stakeholders that projects currently in the SRP pipeline (and likely to qualify for the TI) are constrained in their ability to find further cost efficiencies, given that many such projects are relatively far along in the development process. As an example, several solar stakeholders indicated to the Consulting Team and BPU that their projects have already entered into contracts with project offtakers, and do not have the flexibility to reduce costs without renegotiating their current counter-party agreement.

[3] The Consulting Team further assumes that Community Solar projects (including Community Solar projects that serve LMI populations) also pay an O&M premium relative to a similarly situated non-Community Solar project.

- **Revised Consulting Team Approach:** Given concerns regarding the cost inflexibility of relatively mature projects eligible for the TI, the Consulting Team in consultation with BPU Staff revised the Base Case installed cost assumption upward to equal the 50th percentile of SRP cost data, with a +/- 20 percentage point spread (i.e., 70th and 30th percentiles) for the High and Low Cost Cases, respectively, for this TI Addendum modeling analysis.[4] A comparison of the initial and revised upfront capital cost values can be found in Appendix A, while the upfront capital cost adders can be found in Appendix B.
- **Impact of Revised Approach:** Increasing the assumed upfront capital cost values has a major impact across Project Types, raising incentive requirements on a $/MWh basis.

2.2. Third Party Ownership Market Penetration Assumptions

- **Initial Consulting Team Approach:** The Consulting Team's approach to calculating incentive requirements is based on weighted average market shares by Project Type,[5] as well as the assumed market share of third party-owned (TPO) and host-owned projects. In estimating the TPO market shares, we assumed that TPO projects would maintain the historical market shares observed in the population of projects already installed and operating in New Jersey.
- **Concerns Raised with Initial Consulting Team Approach:** Some solar stakeholders asserted that, while TPO systems have commanded a large market share to date in New Jersey, the TI is only open to projects that are currently in (or will be in) the SRP pipeline by the time 5.1% of the energy sold in New Jersey is generated by solar (the 5.1% Milestone), which is a distinctly different population of systems than the full population of operating projects. According to the SRP pipeline data, there is a larger share of host-owned projects in the pipeline than has been installed to date.[6]
- **Revised Consulting Team Approach:** In response to this feedback, the Consulting Team recalculated the market shares based on available SRP pipeline data (see Appendix C for a full comparison of TPO market shares from the initial and revised analyses).

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[4] The Consulting Team in consultation with BPU Staff utilized this spread to account for an assumption of a 30% scrub rate of projects in the pipeline, which would yield a maximum of 70% of the projects assumed to be in the pipeline at the time of the 5.1% Milestone (thereby corresponding with the new cost percentile in the High Cost case).

[5] A full list of the Project Types employed in the analysis can be found in several documents issued by the Consulting Team and are also attached in Appendix A for convenience.

[6] See Appendix C for a comparison of TPO shares utilized in the initial analysis, as well as the amounts assumed in the revised analysis. We note that the SRP database is unable to provide clear market share data at the granular levels more typical in Massachusetts (where projects are categorized as carports, community solar, landfill, brownfield, etc.). Thus, market shares for these market sectors are estimates based on the Consulting Team's experience with these market subsectors.

- **Impact of Revised Approach:** The net effect of this change is an increase in proposed incentive requirements for all Project Types. This assumption change has the largest relative impact on the <=25 kW, given that host-owned projects >25 kW tend to have a wider distribution of capital and operating costs, as well as higher financing costs (and thus larger incentive requirements). As a result, the same absolute increase on a percentile basis for a <=25 kW project will increase its incentive gap/cost of entry by a much larger relative amount than making the same change to a larger project.

2.3. Year 1 Capacity Factors

- **Initial Consulting Team Approach:** To estimate the Year 1 capacity factors for all projects, the Consulting Team utilized NREL's PVWatts online tool to calculate production under non-ideal siting conditions (i.e., tilts and azimuths) intended to estimate real-world siting condition and performance. Specifically, the Consulting Team assumed that the fleet of projects <=25 kW would *on average* regularly be sited in conditions producing materially imperfect azimuths and tilts, as they are all assumed to be roof-mounted and their tilts and orientations are largely constrained by the roof tilts and orientations of New Jersey's housing stock. In the absence of detailed data, the Consulting Team made an assumption about fleet performance. In contrast, other Project Types tend to be configured in more idealized tilt and azimuth as they are less constrained by non-ideal mounting surfaces.
- **Concerns Raised with Initial Consulting Team Approach:** During the technical session held by the Consulting Team, solar stakeholders raised concerns that utilizing the theoretical production from a single maintained system modeled from PVWatts would, even if utilizing non-ideal siting conditions, overestimate production relative to what is occurring in practice as a result of a variety of factors. Such factors cited by stakeholders include:
  - The average configuration *in practice* (e.g., tilt, azimuth, shading, losses) was worse than assumed by the Consulting Team; and
  - Smaller projects (particularly those in the <=25 kW Incentive Group) will often not receive optimal project maintenance or have a higher assumed degradation rate than standard industry estimates of 0.5%.

  In addition, the *New Jersey Solar Performance Analysis* authored by PJM-EIS that was included as an addendum to the *New Jersey Solar Transition 2019/2020 Transition Incentive Staff Straw Proposal* provided data on actual SREC creation that led to a calculation of annual capacity factors lower than those modeled in PVWatts.
- **Revised Consulting Team Approach:** While some of the discrepancy observable in the PJM-EIS analysis can be traced to the fact that that data represents self-reported SREC generation, and

that the analysis uses a mix of projects of different vintages,[7] the revised Consulting Team approach effectively splits the difference, taking the midpoint between the PVWatts modeled estimates and the PJM-EIS reported data for Year 1 and lifetime production for <=25 kW systems (see Appendix E for the resulting capacity factor estimates).

- **Impact of Revised Approach:** Lower assumed production levels result in a larger gap to be filled by incentives.

2.4. *Inclusion of PPA Discount Factor and Full Energy + Capacity Assumptions*

- **Initial Consulting Team Approach:** When undertaking the type of incentive gap/cost of entry analysis necessary to develop TI incentive levels for TPO systems, the Consulting Team has always modeled a discount to retail rates for all project model "blocks" that is assumed to be offered to offtakers by a third party-owned entity as an inducement to enter into the contract. In effect, this discount increases the project's incentive requirement in order to compensate project owners for finding an offtaker for the power. The Consulting Team had intended to assume a 15% discount to retail rates for such systems, a figure substantiated by solar market participant response to the Cost and Technical Potential survey. In addition, the Consulting Team had also intended to assume full compensation for wholesale energy and capacity for projects not receiving net metering service (specifically, large ground mounted and landfill/brownfield projects in "Preferred Siting" category).
- **Issues Discovered in Consulting Team Model:** While undertaking checks of certain model inputs in response to solar stakeholder questions, the Consulting Team identified a modeling error. While the 15% discount factor input assumption had been inserted in the relevant data input table, it was not properly "connected" in the model (i.e., the spreadsheet formula intended to use this input did not reference the adjustment), and thus this discount was erroneously not taken into consideration. In the process of making the same checks, the Consulting Team also discovered that the forecasted capacity market revenues for projects assumed to receive wholesale compensation were erroneously omitted for just Year 1 of their commercial operation.
- **Revised Consulting Team Approach:** These coding issues have nonetheless been corrected, and quality control has verified that the non-incentive revenue for each Project Types affected are now properly calculated.
- **Impact of Revised Approach:** The impact of properly applying the 15% discount factor was to reduce non-incentive revenue by approximately 3¢/kWh for <=25 kW Incentive Group, and

[7] As an example, some of the projects in the PJM-EIS sample have been operating for a very long time (far longer than the 2014 start of the production analysis) and had significant degradation already incorporated. This had the effect of skewing capacity factors lower than what would be expected for Year 1 production.

approximately 1.5¢/kWh for all other Incentive Groups, thereby increasing incentive requirements by the same amount. The net effect of proper incorporation of Year 1 capacity revenue for the wholesale projects was far smaller, serving to slightly reduce incentive requirements for wholesale projects. The impact was small because the change only affected one year of revenue, rather than an entire (albeit discounted) revenue stream.

2.5. Inclusion of ITC and Tax Rate Differentiation for Host-Owned Systems

- **Issues Discovered in Consulting Team Model:** The Investment Tax Credit ("ITC") is available to both TPO and host-owned, tax-eligible project owners. In undertaking some additional modeling, the Consulting Team inadvertently only included tax benefits for TPO projects, and not for host-owned projects. In addition, the Consulting Team also reset the assumed tax rate for two, non-residential Project Types: Host Owned Small Commercial Roof Mount Project Type (13.2 kW) and the Host Owned Medium Commercial Roof Mount Project Type (250 kW). The assumed values were incorrectly set at 5.95%, an individual income tax rate, rather than the business rate of 9%.
- **Revised Consulting Team Approach:** The errors were corrected for this latest version of the Addendum.
- **Impact of Revised Approach:** The impact of accounting for the ITC for host-owned projects is unevenly distributed across the Incentive Groups because the assumed percentage of host ownership and TPO varies dramatically by Project Type. For example, the Community Solar Incentive Group is assumed as 0% Host Owned, therefore the impact of the correction is zero change in the incentive gap/cost of entry results. On the other hand, the roof and building mounted Project Types (which are listed in Appendices A and C) have Host Owned Percentage ranges from 35% to 59% In these cases the correction substantially reduces the incentive gaps calculated as part of the September 25, 2019, Report Addendum. Correction of the state tax rates only affected two Project Types out of a total of twenty-four, and thus has a negligible impact on overall results.

2.6. "Safe Harbor" Treatment for <=25 kW projects

- **Initial Consulting Team Assumption:** As described in its presentation on June 14, 2019, the Consulting Team previously assumed that all TI projects would retain the ability to "safe harbor" at the 30% solar ITC value, given that developers had indicated their desire to get as many of their projects into the Legacy SREC program by the attainment of the 5.1% Milestone as is feasible. This decision had been made at that time for four reasons:
    - To avoid potential modeling complexities with determining safe harbored tax credit thresholds that could notionally apply to TI projects reaching commercial operation during Energy Years 2021-2024;
    - Projects seeking to qualify for the Legacy SREC program (which is likely to close in calendar year 2020) would be likely to qualify for the "physical work" or the "five percent" tests

required under IRS 2018-59 (the IRS guidance on how taxpayers can safe harbor the value of the solar ITC in a given year).

- The Consulting Team's initial understanding was that all TI-eligible projects were notionally capable of safe harboring at a previous tax year's ITC level; and
- All the owners of various projects were assumed to be taxable entities with enough tax appetite to claim the solar ITC at its full value. The Consulting Team's market-wide research suggests that this is a reasonable assumption, given that government/nonprofit ownership of individual projects has not been a durable trend in solar project development.

- **Concerns Raised with Initial Consulting Team Approach:** Several solar stakeholders suggested that it would be difficult, if not impossible, for many, if not most solar projects that are <=25 kW to safe harbor and that it was not even possible for host-owned residential projects to do so.
- **Revised Consulting Team Approach:** Upon further review of the IRS safe harbor guidance, the Consulting Team agrees that when a non-business taxpayer is the owner, the safe harboring provisions do not apply. In addition, while the larger TPO sellers are likely to have the ability to safe harbor via purchase of modules, the Consulting Team has chosen to assume that safe harboring should not be a default assumption for <=25 kW projects. However, the Consulting Team continues to assume that >25 kW projects are highly likely to be owned by business taxpayers (covered under Section 48 of the US Tax Code, and thus eligible for safe harbor treatment). In addition, since the projects in the SRP pipeline are aiming to reach commercial operation prior to attainment of the 5.1% Milestone, the Consulting Team assumes that such projects have met applicable safe harbor thresholds laid out in IRS 2018-59 (linked above) by completing sufficient physical work or spending five percent of their total project cost (or the equivalent) through module or other equipment purchases (if not substantial construction of the system itself). Thus, all projects <=25 kW are assumed to have an ITC percentage of 26 percent (the value applicable during calendar year 2020), and all others are assumed to achieve safe harbor with a 30% ITC for the TI.
- **Impact of Revised Approach:** For the <=25 kW Incentive Group, the impact of assuming a 26 percent ITC value on incentive gap/cost of entry under all the main policy scenarios (15 year/Base Cost) is approximately a $10/MWh increase relative to a 30 percent ITC value assumption.

2.7. *Target After-Tax Equity IRR for <=25 kW Projects*

- **Initial Consulting Team Approach:** Initially, the Consulting Team assumed that host-owned <=25 kW projects could assume an after-tax equity IRR of between 6.5% and 7.0% for Base Cost projects, depending on whether the incentive revenue stream was fixed (and thus hedged) or floating with supply and demand for TRECs. Such a value is common to assume as a longer-term return on equity capital in the stock market (e.g., the longer-term return on the S&P 500).
- **Concerns Raised with Initial Consulting Team Approach:** Some solar industry stakeholders suggested that these returns were insufficient to make the investment in solar worthwhile for individuals who were unlikely to be in their homes for a long period of time.

- **Revised Consulting Team Approach:** At the request of the BPU, the Consulting Team has aligned the assumed after-tax equity IRR for <=25 kW projects to match the 12%-13% assumed for host-owned solar projects larger than 25 kW. Those latter rates are intended to be roughly equivalent to a corporate hurdle rate utilized by larger businesses when considering purchasing a solar project), and they vary by policy case.
- **Impact of Revised Approach:** Assuming a uniform host-owned after-tax equity IRR results in an increase of approximately $30-$35/MWh in the assumed incentive gap/cost of entry for a host-owned <=25 kW project, depending on the policy case in question.

3. Revised Analysis Results

Below we provide revised analysis results for the reference 15-year, Base Cost Case policy cases (TI-2a, TI-3 and TI-4), as well as TI-4 duration and cost sensitivities requested by BPU. These results directly reflect the changes detailed in Section 2 and include:

- Weighted Average Levelized Incentive Gaps in PSEG Territory;
- Cost-Based TREC Factors;[8]
- Transition Incentive ACPs and Revenue Per TREC;
- Cost Cap Headroom Impacts; and
- Average TI Incentive vs. Legacy SREC Incentive by Reference Policy Case.

3.1. Clarification Regarding Buyer of Last Resort Policy Case Results

The TI-3 option is intended to closely approximate the market-based TREC valuation option from the Straw Proposal that includes a proposed Buyer of Last Resort. When interpreting results from this policy type, it is important to keep in mind the following Consulting Team assumptions:

- **TREC Floor Price:** Under this option, New Jersey's electric distribution companies ("EDCs") would offer to purchase a project's TRECs at a "pre-established floor price…that ensures **a contribution to a return on investment** for eligible transition projects" (emphasis added).[9] For modeling purposes, the Consulting Team interprets the voluntary "contribution" value received by market participants to be equivalent to the incentive gap/cost of entry for a project provided with a fixed TREC payment. In short, this "contribution" value is equal to the incentive gaps/costs of entry for projects in a TI-4 policy case.
- **TREC Prices and Costs to Ratepayers in Short TREC Market Conditions:** As a simplifying assumption, the Consulting Team also assumes that the cost to ratepayers of a Buyer of Last Resort option is a function of market participation in the hedge option from the start of commercial operation. The Consulting Team understands that, as proposed in the Staff Straw Proposal, participants in the Hedged Option would have to submit their expiring TRECs annually in order to receive the (effective) floor price. Our estimates presented herein likely understate the potential cost of a market-based TREC valuation option with a Buyer of Last Resort if the market is short. However, the results would be comparable if the market is in surplus.

[8] The TREC Factors are an interim step in the modeling process. TREC Factors are the calculated output of the relative incentive gap for each individual Incentive Group for each specific modeling case (See Table 4 below). The Cost-Based TREC Factors for the main policy cases are provided in Table 5.

[9] See Page 7 of 12 of the 2019/2020 Transition Incentive Staff Straw Proposal, available at: https://nj.gov/bpu/pdf/publicnotice/Transition%20Incentive%20Staff%20Straw%20Proposal%20-%20Comment%20Period%20Extension%209-13-19.pdf

- **Ratepayer Cost Impacts of Hedged Purchase Available Only to Expiring TRECs:** Another difference between the modeled TI-3 case and the Buyer of Last Resort option in the Staff Straw Proposal is that the Hedged Purchase Option in the Staff Straw Proposal is limited only to expiring TRECs reaching the end of their qualification life. Under the Staff's proposal, the probability of breaching the Cost Cap during the "Kink" years might be diminished because some incentive costs (i.e., those related to expiring TRECs) passed on to ratepayers would be delayed until after the expiration of the TREC's life (which in many cases occurs after the "Kink" period).[10]
- **Cost as Function of "Hedge Option" Participation:** Thus, the maximum potential cost of a TI-3 option could be as high as the cost of the TI-2a option (in which no market participant chooses to sell their TRECs at the EDC-offered price), and as low as the TI-4 policy cost, plus a 5% "frictional" cost estimate (to account for potential markup/administrative costs charged by EDC procurers).

3.2. Weighted Average PSEG Levelized Incentive Gap and Cost-Based TREC Factors

As discussed in Attachment 1 to the initial report, the weighted average levelized incentive gaps/costs of entry for each Incentive Group are calculated by weighting the costs of entry for the 24 Project Types by their expected market shares, which incorporate the expected market shares for TPO and host-owned projects. For the Report Addendum, the TPO/Host market share splits were revised as shown in Appendix C, but the overall market shares per Project Type did not change. Table 2 compares the initial incentive gap/cost of entry results by Incentive Group with the revised results (i.e., also incorporating the changes described in Section 2). Table 3 displays the 2019 weighted average levelized incentive gap for PSEG by TI-4 sensitivities in dollars per MWh. The sensitivities include varying term of incentives in years and bounding cases by combining term length with cost case.

[10] Related to the points just made, the practical impact on ratepayer costs in any given year under a scenario where the hedge purchase is only available to expiring TRECs also will be a function of (1) the fraction of TRECs used during their normal lifetime to comply with the TREC requirements for load serving entities, plus (2) the TRECs that take advantage of the floor price option upon expiration.

Table 2 - 2019 Weighted Average Levelized Incentive Gap for PSEG by Reference Policy Case ($/MWh)

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Analysis Vintage	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
TI-2a - DO w/ TREC Factors (Base Cost, 15 Years)	Initial	$141	$141	$113	$110	$84	$32
	First Revision	$158	$168	$140	$138	$84	$92
	Second Revision	**$143**	**$130**	**$140**	**$138**	**$83**	**$106**
TI-3 & TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	Initial	$128	$127	$103	$99	$74	$10
	First Revision	$144	$152	$129	$126	$75	$69
	Second Revision	**$129**	**$115**	**$129**	**$126**	**$73**	**$75**

Table 3 - 2019 Weighted Average Levelized Incentive Gap for PSEG by TI-4 Sensitivities ($/MWh)

Incentive Group → (Cost Profile & Incentive Term)↓	Metric	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
Base Cost/ 15 Year	*Main TI-4 Case*	$129	$115	$129	$126	$73	$75
High Cost/ 10 Year	**Revised Sensitivity**	**$220**	**$201**	**$212**	**$211**	**$120**	**$168**
Base Cost/ 10 Year	**Revised Sensitivity**	**$157**	**$139**	**$158**	**$155**	**$90**	**$92**
Base Cost/ 20 Year	**Revised Sensitivity**	**$116**	**$105**	**$115**	**$113**	**$66**	**$68**
Low Cost/ 20 Year	**Revised Sensitivity**	**$83**	**$75**	**$86**	**$84**	**$48**	**$17**

Some observations on the model results presented in Table 3 include:

- Relative to the base TI-4 case (15 years, Base Cost), setting installed costs at the 70th percentile with a 10-year term has the most significant impact on the incentive gap the TI must fill, whereas reducing the term to 10 years from 15 years reduces incentive gaps; and
- Shortening the incentive term increases incentive gaps/costs of entry substantially more than lengthening the term reduces them.

The incentive gap/cost of entry figures shown in Section 3.2 above, when taken as a ratio of the highest number to the number in question, produces the following cost-based TREC Factors for the reference 15 Year, Base Cost policy cases.

Table 4 and Table 5 below show the cost-based TREC Factors by Reference Policy Option and the requested TI-4 sensitivities, respectively. They are to be read as factors of the proposed ACP schedule provided in Attachment 2.

Table 4 – Cost-Based TREC Factors by Reference Policy Option

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Analysis Vintage	Preferred Siting	Building Mounted	Comm. Solar	LMI	Ground Mounted	<=25 kW
TI-2a - DO w/ TREC Factors (Base Cost, 15 Year)	Initial	1.00	1.00	0.80	0.78	0.59	0.23
	First Revision*	0.94	1.00	0.83	0.82	0.50	0.55
	Second Revision	**1.00**	**0.91**	**0.98**	**0.97**	**0.58**	**0.74**
TI-3 & TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	Initial	1.00	0.99	0.80	0.77	0.58	0.08
	First Revision*	0.95	1.00	0.85	0.83	0.49	0.45
	Second Revision	**1.00**	**0.89**	**1.00**	**0.98**	**0.57**	**0.58**
*The initial Report Addendum included proposed TREC factors that were set administratively based on the modeling results, whereas these values represented the raw ratio of cost of entry values to the highest cost Incentive Group (in that case, Building Mounted).							

Table 5 – Cost-Based Fixed TREC Factors by TI-4 Sensitivity

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
Base Cost, 15 Year	1.00	0.89	1.00	0.98	0.57	0.58
High Cost, 10 Year	**1.00**	**0.92**	**0.96**	**0.96**	**0.55**	**0.76**
Base Cost, 10 Year	**1.00**	**0.88**	**1.00**	**0.98**	**0.57**	**0.58**
Base Cost, 20 Year	**1.00**	**0.90**	**0.99**	**0.97**	**0.57**	**0.59**
Low Cost, 20 Year	**0.96**	**0.87**	**1.00**	**0.97**	**0.56**	**0.20**

3.3. Net Present Value of Ratepayer Cost

The Consulting Team multiplied the revised estimates of revenue per TREC by the amount of TREC capacity and production estimated in the initial report to derive the revised net present value ("NPV") estimates for the reference TI policy cases, as shown below in Table 6.[11]

Table 6 - Net Present Value (NPV) of Direct Ratepayer Costs by Reference TI Policy Case

Case/Sensitivity	Ratepayer NPV (Initial Analysis, $MM)	Ratepayer NPV (First Revision, $MM)	Ratepayer NPV (Second Revision, $MM)	Δ from first revision ($MM)
TI-2a - DO w/ TREC Factors (Base Cost -15 Year)	$800	**$921**	**$793**	**-$128**
TI-3 - DO w/ TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	$594-$800†	**$691-$921†**	**$584-$793†**	**-$107 to -$128**
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	$566	**$658**	**$556**	**-$102**
†Please see Section 3.1 for detailed guidance on how to interpret the potential cost to ratepayers of TI-3.				

Relative to the findings in the initial TI report, the NPV of the cost to ratepayers ranges from $7-$10 million less than in the initial TI report (as shown in Table 6). Like both the TREC Factors and incentive gap/cost of entry figures, NPVs for all cases have fallen as a result of the changes in assumptions discussed in Section 2. The Fixed TREC (TI-4) option (in which market participants hedge their revenue stream at a fixed price) would cost New Jersey ratepayers $237 million less on an NPV basis than a policy in which prices are set strictly by TREC supply and demand (TI-2a). Depending upon how TI-3 is implemented and received by the market, the cost to ratepayers is expected to be somewhere in between TI-2a and TI-4.

Table 7 - Net Present Value (NPV) of Direct Ratepayer Costs by TI-4 Sensitivity

Case/Sensitivity	Total NPV Costs to Ratepayers ($MM)
TI-4 - Partial Long-Term Hedge (Low Cost - 20 Year)	**$401**
TI-4 - Partial Long-Term Hedge (Base Cost -10 Year)	**$551**
TI-4 - Partial Long-Term Hedge (Base Cost - 20 Year)	**$571**
TI-4 - Partial Long-Term Hedge (High Cost - 10 Year)	**$791**

As was also the case in the initial TI report, we continue to find that, all other factors equal, policy cases with shorter incentive durations and/or lower costs tend to have the lowest overall costs to ratepayers.

[11] For reference, the Consulting Team uses an estimated pipeline size of 483 MW.

However, as Table 7 above shows, the $390 million spread between the lowest cost ($401 million) and highest cost ($791 million) sensitivities is nearly equivalent to the lowest cost option, which provides a longer term (20 year) – and thus higher NPV – incentive than one of shorter duration.

3.4. Annual Ratepayer Costs (and Associated Cost Cap Impacts)

As discussed extensively in the initial TI Report and prior stakeholder workshops, the Clean Energy Act of 2018 requires that the cost to ratepayers of Class I RPS compliance (excluding the cost of offshore wind procurement) cannot exceed nine percent of the total paid each year for electricity through Energy Year 2021 and seven percent thereafter. The law further requires BPU to take any and all steps to avoid exceeding these caps. Thus, ensuring enough headroom during the "Kink" period has served (and will continue to serve) as a critical consideration for designing the TI.

As shown in the revenue per TREC results discussed in this section, our revised analysis continues to utilize a "Custom Alternative Compliance Payment ("ACP")".[12] Along with the TREC Factors, the Custom ACP adjusts the amount of potential compensation for TI-eligible projects to reduce the risk of breaching the Cost Cap during the Kink period. The Custom ACP has the effect of leaving the Kink period headroom values we estimated in the initial TI report unchanged.

Table 8 and Table 9 show the initial and the revised average revenue (and thus ratepayer cost) per TREC, respectively.

Table 8 –Initial & Revised Average Revenue/Ratepayer Cost ($/TREC, Reference Cases)

Case/Sensitivity	Analysis Vintage	EY 2021 (9% Cap)	EY 2022 (7% Cap)	EY 2023 (7% Cap)	EY 2024 & After (7% Cap)
TI-2a - DO w/ TREC Factors (Base Cost/15 Year)	Initial	$75	$67	$61	$219
	First Revision	$75	$67	$61	$266
	Second Revision	**$75**	**$67**	**$61**	**$222**
TI-3 - DO w/ TREC Factors & Firmed Hedge Option (Base Cost/15 Year)	Initial	$65	$59	$53	$155
	First Revision	$65	$59	$53	$189
	Second Revision	**$65**	**$59**	**$53**	**$156**
TI-4 - Partial Long-Term Hedge (Base Cost/15 Year)	Initial	$65	$59	$53	**$155**
	First Revision	$65	$59	$53	$189
	Second Revision	**$65**	**$59**	**$53**	**$156**

[12] The Custom ACP values included in the initial TI report analysis have not been changed, and the Consulting Team does not recommend changing them to allow for more substantial Cost Cap exposure during the Kink period, unless BPU plans to make changes to the Legacy SREC program. The Consulting Team further notes that when Legacy SREC prices are matched with the High Legacy SREC case discussed in the initial TI Report, the Cost Cap is highly likely to be breached in EY 2022 and EY 2023.

Table 9 - Revised Average Revenue/Ratepayer Cost ($/TREC, TI-4 Sensitivities)

Case/Sensitivity	EY 2021 (9% Cap)	EY 2022 (7% Cap)	EY 2023 (7% Cap)	EY 2024 & After (7% Cap)
Base Cost/15 Year	*$65*	*$59*	*$53*	*$156*
Base Cost/20 Year	**$65**	**$59**	**$53**	**$134**
Low Cost/20 Year	**$65**	**$59**	**$53**	**$95**
Base Cost/10 Year	**$65**	**$59**	**$53**	**$216**
High Cost/10 Year	**$65**	**$59**	**$53**	**$314**

Table 10 and Table 11 below show the change in the forecasted EY 2024 Clean Energy Act Cost Cap headroom by Reference Policy Case and requested TI-4 sensitivities, respectively.

Table 10 – Change in Clean Energy Act Class I Cost Cap Headroom During EY 2024 by Reference Policy Case (EY 2024, $MM)

Cases and Sensitivities (Cost Profile & Incentive Term)	Legacy SREC Price/ Cost Outlook	Metric	EY 2024 (7% Cap)
TI-2a - DO w/TREC Factors (Base Cost/15 Year)	High	Initial	$27
		First Revision	$9
		Second Revision	**$28**
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost/15 Year)	High	*Initial*	$57
		First Revision	$43
		Second Revision	**$58**
TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	High	*Initial*	*$61*
		First Revision	$47
		Second Revision	**$62**

Table 11 - Change in Clean Energy Act Class I Cost Cap Headroom During EY 2024 by TI-4 Sensitivity (EY 2024, $ in Millions)

Cases and Sensitivities (Cost Profile & Incentive Term)	Legacy SREC Price/Cost Outlook	Metric	EY 2024 (7% Cap)
High Cost/10 Year	High	*Revised TI-4 Base Case*	*$62*
		Sensitivity	($16)
		Δ from TI-4 Base Case	**($78)**
Base Cost/10 Year	High	*Revised TI-4 Base Case*	*$62*
		Sensitivity	**$33**
		Δ from TI-4 Base Case	**($29)**
Base Cost/20 Year	High	*Revised TI-4 Base Case*	*$62*
		Sensitivity	**$73**
		Δ from TI-4 Base Case	**$11**
Low Cost/20 Year	High	*Revised TI-4 Base Case*	*$62*
		Sensitivity	**$94**
		Δ from TI-4 Base Case	**$32**

Finally, Figure 1 and Figure 2 below illustrate the specific Cost Cap impact through Energy Year ("EY") 2030 for TI-2a, while Figure 3 and Figure 4 (also below) illustrate the specific Cost Cap impact through EY 2030 for TI-3. Finally, Figure 5 and Figure 6 illustrate the specific Cost Cap impact through EY 2030 for TI-4.

Figure 1 – Cost Cap Impact of Base Cost/15 Year TI-2a (DO w/TREC Factors) Under Base Case Legacy SREC Price Outlook

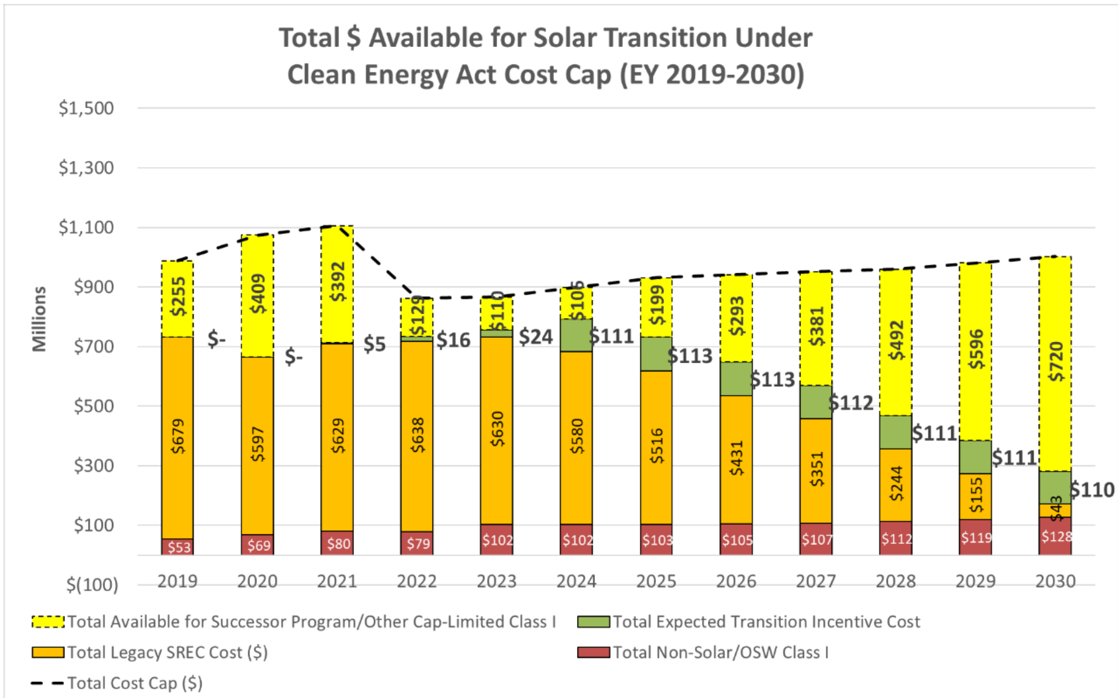


Figure 2 – Cost Cap Impact of Base Cost/15 Year TI-2a (DO w/TREC Factors) Under High Case Legacy SREC Price Outlook

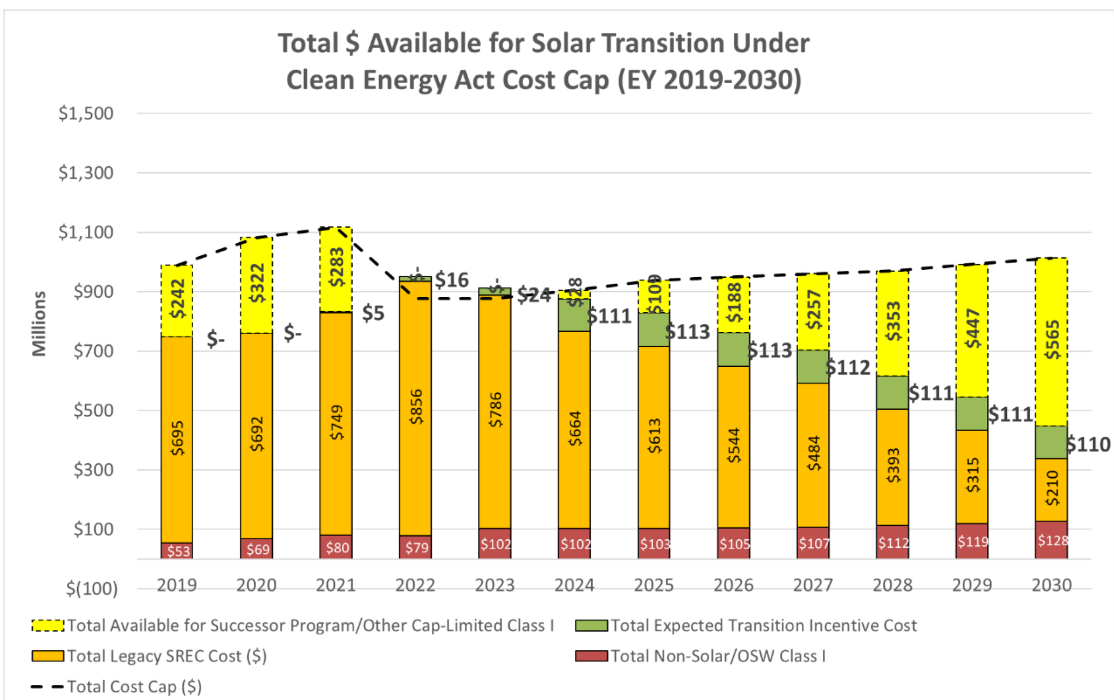


Figure 3 – Cost Cap Impact of Base Cost/15 Year TI-3 (DO w/TREC Factors & Firmed Hedge Option) Under Base Case Legacy SREC Price Outlook

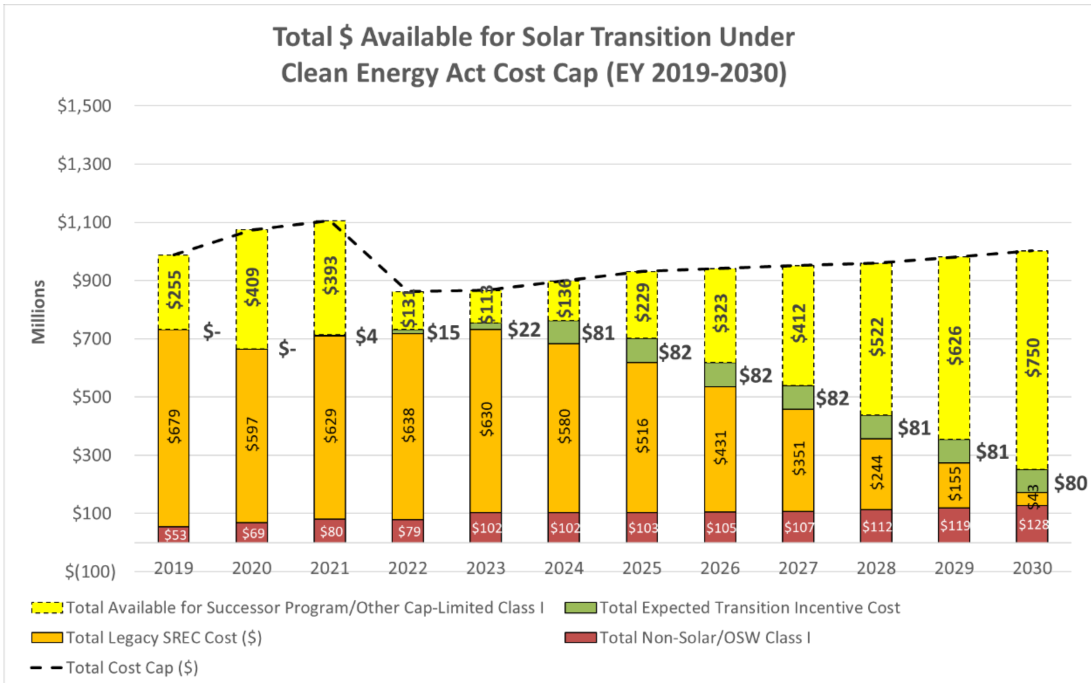


Figure 4 – Cost Cap Impact of Base Cost/15 Year TI-3 (DO w/TREC Factors & Firmed Hedge Option) Under High Case Legacy SREC Price Outlook

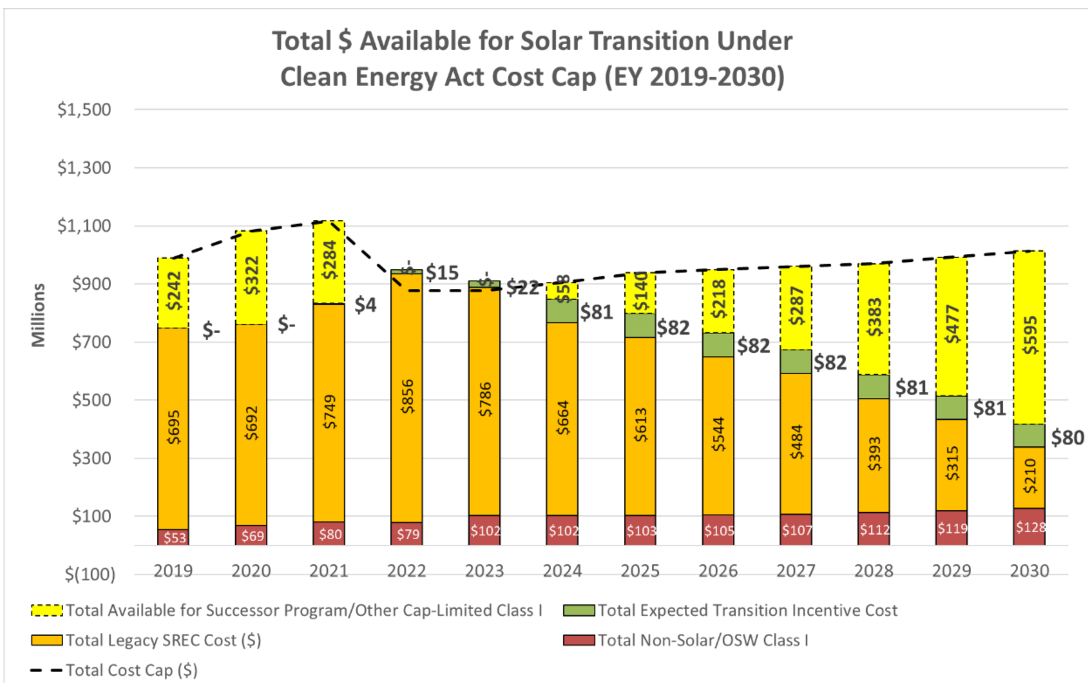


Figure 5 - Cost Cap Impact of Base Cost/15 Year TI-4 (Partial Long-Term Hedge) Under Base Case Legacy SREC Price Outlook

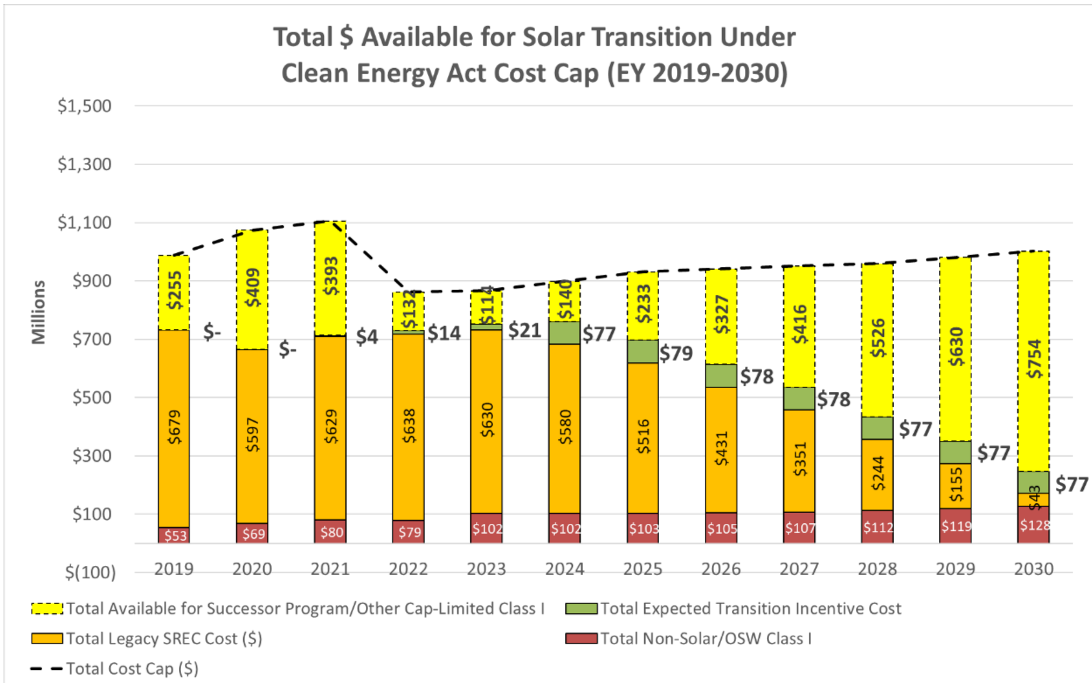
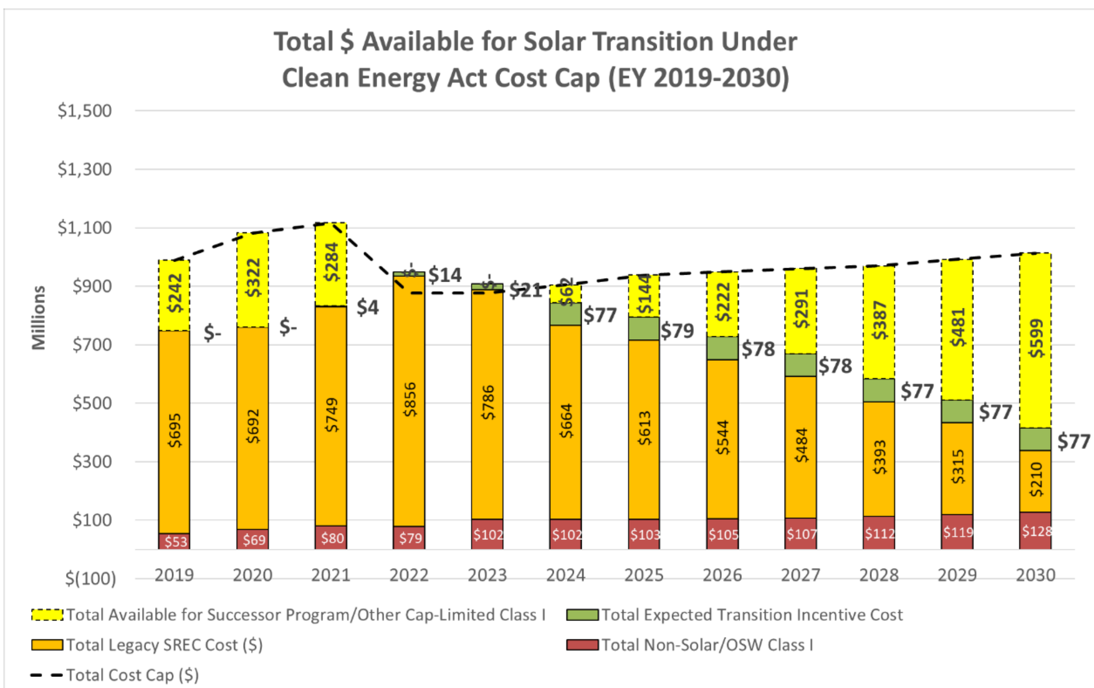


Figure 6 - Cost Cap Impact of Base Cost/15 Year TI-4 (Partial Long-Term Hedge) Under High Case Legacy SREC Price Outlook



3.5. *Average TI Incentive vs Legacy SREC Incentive $/MWh by Reference Policy Case*

One of the goals for the TI is to save ratepayers money relative to the Legacy SREC program on a cost per unit of energy delivered ($/MWh) basis.[13] In order to understand the impact of increasing incentive values, it is necessary to compare (as was initially undertaken in the Initial TI Report) Base Case Legacy SREC revenue to TI revenue over the same term as the TI incentive analyzed by reference policy case (by comparing levelized NPVs of projects). Table 12 compares the initial and revised results.

Table 12 – Comparison of Base Case Legacy SREC and Proposed TI Levelized $/MWh Revenue (Reference Policy Cases)

Cases and Sensitivities (Cost Profile & Incentive Term)	Analysis Version	Levelized Base Case Legacy SREC $/MWh Over TI Term (CY 2019 COD)	Levelized Legacy SREC $/MWh Over TI Term (CY 2020 COD)	Weighted Avg TI NPV over TI Term ($/MWh)	%▲ (CY 2019 COD Legacy SREC)*	%▲(CY 2020 COD Legacy SREC)*
TI-2a - DO w/TREC Factors (Base Cost/15 Year)	*Initial*	$131	$116	*$138*	*5%*	*19%*
	First Revision	**$131**	**$116**	**$160**	**22%**	**38%**
	Second Revision	**$131**	**$116**	**$139**	**6%**	**20%**
TI-3 & TI-4 - Partial Long-Term Hedge (Base Cost/15 Year)	*Initial*	$130	$115	*$100*	*-23%*	*-13%*
	First Revision	**$130**	**$115**	**$117**	**-10%**	**2%**
	Second Revision	**$130**	**$115**	**$100**	**-23%**	**-13%**
*Positive % change values denote a higher cost TI than Legacy SREC incentive for a project reaching commercial operation during the Energy Year in question. Negative values denote a lower cost TI than Legacy SREC incentive for a project reaching commercial operation during the Energy Year in question.						

The results as revised show that increasing incentive values means that market-based TREC options without any built-in hedging options (TI-2a) are now more expensive to ratepayers than the Legacy SREC

[13] See New Jersey Solar Transition Staff Stakeholder Notice, issued April 8, 2019, available at: http://www.njcleanenergy.com/files/file/Solar%20Transition%20Stakeholder%20Notice%202019-04-08-19.pdf

program (if the Consulting Team's modeling assumptions for Legacy SREC program costs and Legacy SREC prices are accurate). Options that allow voluntary (TI-3) and required (TI-4) hedged EDC purchases have a lower cost to ratepayers than Legacy SREC projects likely to reach commercial operation in 2019 and 2020.[14]

Table 13 - Comparison of Legacy SREC and Proposed TI Levelized $/MWh Revenue (TI-4 Sensitivities)

Cost Profile & Incentive Term	Analysis Version	Levelized Base Case Legacy SREC $/MWh Over TI Term (CY 2019 COD)	Levelized Base Case Legacy SREC $/MWh Over TI Term (CY 2020 COD)	Weighted Avg TI NPV over TI Term ($/MWh)	%▲ (CY 2019 COD Legacy SREC)*	%▲ (CY 2020 COD Legacy SREC)*
Base Cost/ 15 Year	*Second Revision*	*$130*	*$115*	$100	-23%	-13%
High Cost/ 10 Year	*Second Revision*	**$162**	**$146**	**$171**	**5%**	**17%**
Base Cost/ 10 Year	*Second Revision*	**$162**	**$146**	**$122**	**-25%**	**-17%**
Base Cost/ 20 Year	*Second Revision*	**$112**	**$99**	**$90**	**-20%**	**-9%**
Low Cost/ 20 Year	*Second Revision*	**$112**	**$99**	**$65**	**-42%**	**-34%**
*Positive % change values denote a higher cost TI than Legacy SREC incentive for a project reaching commercial operation during the Energy Year in question. Negative values denote a lower cost TI than Legacy SREC incentive for a project reaching commercial operation during the Energy Year in question.						

Table 13 compares the revised Base Cost/15 Year results for the TI-4 (fixed TREC) option to the duration and cost sensitivities calculated herein. Like the cost of entry results, project cost assumptions have the greatest impact on the assumed levelized revenue. Specifically, assuming High Cost (70th percentile of upfront capital costs in the market) and shorter incentive term parameters would increase costs beyond the Consulting Team's estimate of Base Case Legacy SREC revenue (+5% to +17%). While assuming Low Cost (30th percentile) revenues would cost ratepayers substantially less than Legacy SREC projects, setting prices to that level could increase TI project attrition rates.

[14] For the initial TI Report (as shown on p. 25 of that report), the Consulting Team developed a Legacy SREC price forecast, which was discussed at Stakeholder Workshops #1 and #2 in May and June 2019. In order to compare the relative cost on a levelized basis of the potential TI relative to the Legacy SREC program, the Consulting Team calculated the levelized expected incentive values of projects reaching commercial operation in EY 2020 as compared to those reaching commercial operation in EY 2019. The Base Case Legacy SREC price forecast assumes declining values over time, and thus projects reaching commercial operation in EY 2020 would receive lower incentives than those reaching commercial operation in EY 2019.

As illustrated in the initial report, the term of the incentive also makes a significant difference on a $/MWh basis. Decreasing the term of the incentive results in a policy with higher per-unit costs than the Legacy SREC program. This occurs because the Base Case Legacy SREC price outlook utilized herein assumes relatively higher prices within the first 10 years of commercial operation than over 15 or 20 years.

4. Options Analysis and TI Recommendation

4.1. Options Analysis

In addition to the overarching objective of continuing to support the growth of the solar industry, two of BPU Staff's stated priorities in designing a TI are (in no specific order of importance):

- Limiting overall costs to ratepayers (as expressed in terms of NPV of direct ratepayer cost over the life of the incentive); and
- Limiting risk of breaching the Cost Cap (as expressed in this Report Addendum as the amount of headroom available in Energy Year 2024).[15]

As in the initial TI report, the Consulting Team has ranked each Reference Policy Case and TI-4 sensitivity in order to determine which option represents an appropriate co-optimization of these objectives.

Table 14 – Ranking of Reference Policy Cases by EY 2024 Headroom and NPV of Ratepayer Cost

EY 2024 Headroom Rank	Case/Sensitivity	EY 2024 Headroom ($MM)†	NPV Rank	Case/Sensitivity	NPV ($MM)
1	TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	**$62**	1	TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	**$556**
2	TI-3 - DO w/TREC Factors and Firmed Hedge Option (Base Cost, 15 Year)	**$58**	2	TI-3 - DO w/TREC Factors and Firmed Hedge Option (Base Cost, 15 Year)	**$584-$793†**
3	TI-2a - DO w/TREC Factors (Base Cost, 15 Years)	**$28**	3	TI-2a - DO w/TREC Factors (Base Cost, 15 Years, As Revised)	**$793**
†Figure represents High Legacy SREC Cost/Price Outlook case from initial TI report					

Table 14 contains the ranking of the reference policy cases based on the two criteria described above. The rankings make clear that TI-4 and TI-3[16] provide the largest amount of Cost Cap headroom in EY 2024, and thus can best accommodate the increased incentive values without risk of a substantial breach of the Cost Cap. In terms of cost to ratepayers, a Fixed TREC option would offer the lowest overall cost to ratepayers. While a market-based TREC approach with a Buyer of Last Resort (TI-3) would also offer lower ratepayer cost and higher Cost Cap headroom relative to one without a Buyer of Last

[15] See New Jersey Solar Transition Staff Stakeholder Notice, issued 8 April 2019, available at: http://www.njcleanenergy.com/files/file/Solar Transition Stakeholder Notice 2019-04-08-19.pdf

[16] Assuming substantial participation by buyers and sellers of TRECs in a voluntary hedged purchase program as described on section 3.1 of this Addendum.

Resort (TI-2a), these benefits would be conditional upon voluntary market participant adoption of a "hedged purchase option".

Table 15 - Ranking of TI-4 Sensitivities by EY 2024 Headroom and NPV of Ratepayer Cost

Headroom Rank	Case/Sensitivity	EY 2024 Headroom ($MM)†	NPV Rank	Case/Sensitivity	NPV ($MM)
1	Low Cost/20 Year	**$94**	1	Low Cost/20 Year	**$401**
2	Base Cost/20 Year	**$73**	2	Base Cost/10 Year	**$551**
3	Base Cost/10 Year	**$33**	3	Base Cost/20 Year	**$571**
4	High Cost/10 Year	**($16)**	4	High Cost/10 Year	**$791**
†Figure represents High Legacy SREC Cost/Price Outlook cases from initial TI report					

Table 15 shows the same ratepayer cost and Cost Cap exposure rankings for the TI-4 sensitivities. As might be expected, the Low Cost/20 Year option would provide greater ratepayer cost savings relative to other options. As noted in Section 3.4, the risk of extending the Kink Period grows as the option's cost rises (and incentive term shrinks).

4.2. Revised TI Recommendations

As described in Section 1.3, the Consulting Team recommends adoption of a TI that includes either a voluntary (TI-3) or required (TI-4) hedged TREC purchase as a means of reducing ratepayer cost and risk of breaching the Cost Cap. We describe this recommendation below in terms of 1) our recommended TREC Valuation Option, 2) our recommended cost case, and 3) our recommendation for the term of the TI.

4.2.1. Recommended TREC Valuation Option (Policy Case)

The Consulting Team recommends adoption of a Fixed, factorized TREC design (TI-4), given that it most effectively achieves the BPU Staff's objectives of sustained solar growth, cost mitigation and Cost Cap adherence. However, if the BPU wants to preserve a market-based approach to valuing TRECs, the Consulting Team believes that employing the State's EDCs as Buyers of Last Resort for unpurchased TRECs represents a viable option.

4.2.2. Recommended Cost Case

While setting incentives at Low Cost values would likely offer the greatest ratepayer and Cost Cap benefits, the Consulting Team is concerned that doing so may significantly increase TI project attrition. Conversely, even though adopting High Cost (consistent with 70^{th} percentile upfront capital costs in the SRP pipeline) may be more inclusive for a broader range of development cost structures, the Consulting Team's analysis indicates that setting costs at such a high level appears to pose an unacceptable risk of Cost Cap breach and the accrual of unacceptably high costs to ratepayers.

The Consulting Team therefore recommends setting Base Costs at the 50^{th} percentile Base Case in order to balance ratepayer/Cost Cap benefits and attrition for projects further along in the development process.

4.2.3. Recommended Incentive Term

Maintaining the TREC term at the 15-year term proposed in the Straw Proposal limits the overall NPV of costs to ratepayers. However, increasing the term may help limit Kink period Cost Cap impacts without risking substantial project attrition. For example, employing the Base Cost/20 Year approach would increase ratepayer exposure by $15 million relative to Base Cost/15 Year but offer $11 million in added EY 2024 Cost Cap headroom. Thus, the Consulting Team recommends adoption of either a 15- or 20-year TI term.

5. Perspective on Incentive Gap Requirements

5.1. Introduction

The Consulting Team has reviewed stakeholder comments received prior to October 18, 2019. Many comments from New Jersey market participants have questioned whether the TI incentives calculated in this analysis are sufficient to ensure TI-eligible projects can reach commercial operation.

This section endeavors to provide greater understanding of the reasons for how this can occur, given the model inputs and methodology, by first focusing on the modeled net retail rate revenue retained by project owners, and then focusing on how the Incentive Gap is calculated.

5.2. Modeled Net Retail Revenue Retained by Project Owners

One of the key model assumptions utilized to derive the incentive gaps/costs of entry that determines viable TI incentives is the amount of wholesale or retail revenue that third-party or host owners receive. Two of the primary drivers of this calculation are:

1. The applicable retail/net metering credit rate for net metered projects, or the wholesale price of energy for grid supply projects; and
2. (For TPO projects only) The discounted PPA rate provided by TPOs to project hosts/offtakers reduces the amount of revenue project owners can earn from retail net metering of a host counter-party.

5.2.1. Retail Rate Assumptions

For this analysis, we have assumed forecasted PSEG retail/net metering credit rates as proxies for the first assumption. We did so for the following reasons.

- PSEG has the greatest EDC market share of statewide solar.
- PSEG has the lowest net metering rates of the four NJ EDCs for its most common small commercial and industrial ("C&I") rate class ("G-1") and medium-large C&I rate class ("G-2"). PSEG also has relatively average modeled retail/net metering rates for its most common residential rate class ("R-1"). Table 16 shows the assumed 2019 retail/net metering credit rates for each of the four EDCs for each of the three prototypical modeled rate classes.
- While possible, providing the flexibility of allowing for each Project Type to have its own customized EDC/Prototypical Rate Class combination for the assumed retail/net metering credit within a unique modeling case would take considerable additional programming. This programing effort has not been undertaken, though selected sensitivities have been provided below in Section 5.4 to provide comparable insight into varying the EDC proxy for prototypical retail rates.

Table 16 - 2019 Retail Rates by Prototypical Rate Class and EDC (Nominal ¢/kWh)

EDC	R-1	G-1	G-2
Atlantic City Electric	19.10	14.24	7.90
Jersey CP&L	14.26	16.90	10.63
Rockland Electric	18.04	12.73	N/A
PSEG	17.55	7.59	6.51

Retail/Net Metering Credit Rates: When calculating incentive gaps/cost of entry, lower retail/net metering rates will, all other factors equal, provide less non-incentive revenue, and thus result in a larger gap that incentives must fill for the project to reach investor returns, and vice versa. Comments from industry stakeholders active in the non-residential Incentive Groups have not objected to the use of PSEG retail/net metering credit rates as have stakeholders focused on developing <=25 kW projects.

5.2.2. Discount Rate Assumptions

PPA Discounts for Offtakers: The Consulting Team assumes that third-party owners can offer project offtakers a PPA rate intended to represent a 15% discount to the applicable retail/net metering credit rate (a value derived in part from the feedback received from industry stakeholders to the Consulting Team's Cost and Technical Potential Survey issued in June 2019). In recent comments, several TPO market participants involved in development of systems of varying scales have suggested that they have executed contracts with offtakers with substantially higher discounts (e.g., 25%). They argue that implementing incentives modeled with a 15% discount to applicable retail/net metering rate (at least for the TI) will result in high pipeline attrition, as deals would have to be renegotiated and many would be likely to fail in the process. We note as well, the lower the incentive rate implemented, the higher the attrition rate of Host Owned projects is expected to be.

The modeled incentive gap of TI projects is not determined by these factors in isolation, but instead by their combination and interaction. Specifically, the combination of these factors produces the expected revenue that project owners can expect to retain (if developers/owners can offer sufficiently attractive terms to induce offtakers to participate). Table 17 provides the 2019 modeled retail/net metering rates for each of the four EDCs for each of the of the three prototypical rate classes, assuming 15% and 25% of the energy revenue is assigned to an offtaker.

Table 17 - 2019 Retail/Net Metering Credit Rates by Rate Class and EDC with Discounts Applied (Nominal ¢/kWh)

EDC	15% NEM Discount for TPO			25% NEM Discount for TPO		
	R-1	G-1	G-2	R-1	G-1	G-2
Atlantic City Electric	16.24	12.10	6.71	14.33	10.68	5.93
Jersey CP&L	12.12	14.36	9.03	10.70	12.68	7.97
Rockland Electric	15.34	10.82	N/A	13.53	9.55	N/A
PSE&G	14.92	6.45	5.53	13.16	5.69	4.88

5.3. Incentive Gap Calculation

Table 18 displays the modeled incentive gap assuming PSEG rates for the levelized incentive gap/cost of entry results by Project Type by Ownership for a host-owned system (requiring neither a PPA nor an exogenously-offered discount), a TPO with a 15% PPA discount, a TPO with a 25% PPA discount, and the weighted average blend of the host owned and TPO values at the 15% and 25% discount values. For example, the model calculates a $56/MWh levelized cost of entry for host-owned Residential Roof Mount projects; this is equivalent to the modeled incentive needed to induce development of host-owned Residential Roof Mount projects at (among other assumptions) the Consulting Team's forecast of PSEG retail/net metering rates and a 26% ITC. On the other hand, TPO Residential Roof Mount projects with a 15% discount (14.92 ₵/kWh to the project owner) would require a $86/MWh payment to reach typical investor returns and with a 25% discount (13.16 ₵/kWh to the TPO) would require $110/MWh to reach the same return threshold. The Residential Roof Mount Project Type levelized incentive gap/cost weighted average of host-owned and TPO project is, of course, a value between the host-owned level and the TPO level (i.e., $75/MWh at a 15% discount and $90/MWh at a 25% discount).

In the case of <25 kW Residential Roof Mount projects, the incentive gap/cost host-owned TPO weighted average over incents host-owned systems and under incents TPO systems. As no party (to our knowledge) is suggesting having different TI incentives for host owned vs. TPO systems, then the use of a weighted average is implicitly consistent with how any TI incentive would be implemented (i.e., identical TI incentives for identical Project Types regardless of whether the project is host-owned or TPO).

Table 18 - TI-4 (15 yr, Base Cost) Cost of Entry (COE) by NEM Discount and Project Type ($/MWh) Assuming PSEG Prototypical Rates

Incentive Group	Project Type	Modeled Size (kW_{DC})	Incentive Group Mkt. Share*	% TPO	Host Owned COE (No Disc.)	TPO COE (15% Disc.)	TPO COE (25% Disc.)	Blended COE (15% Disc.)	Blended COE (25% Disc.)
<=25 kW	Residential Roof Mount	7	90%	63%	$56	$86	$110	$75	$90
	Small Commercial Roof Mount	13	10%	63%	$66	$87	$112	$79	$94
Building Mounted	Medium Commercial Roof Mount	250	22%	42%	$137	$147	$157	$141	$145
	Medium Commercial Building Mounted	500	21%	43%	$104	$121	$132	$111	$116
	Large Commercial Building Mounted	1,000	28%	41%	$97	$111	$120	$103	$106
	Very Large Building Mounted	2,000	29%	65%	$103	$114	$122	$110	$116
Preferred Siting	Medium Commercial Lot Carport	250	6%	42%	$173	$182	$192	$176	$181
	Large Commercial/Campus Carport	1,000	10%	41%	$139	$153	$162	$145	$148
	Large Landfill/Brownfield	5,000	42%	100%	$122	$120	$120	$120	$120
	Small Landfill/Brownfield	1,000	24%	100%	$120	$122	$122	$122	$122
	Very Large Carport	2,000	18%	65%	$127	$139	$149	$135	$141
Community Solar	Small Community Solar	1,000	16%	100%	$109	$125	$135	$125	$135
	Very Large Building Mounted Community Solar	2,000	28%	95%	$136	$148	$156	$147	$155
	Medium Community Solar	2,000	28%	100%	$115	$128	$138	$128	$138
	Large Community Solar	5,000	28%	100%	$101	$113	$123	$113	$123
LMI	Small Community Solar (LMI)	1,000	34%	100%	$112	$124	$134	$124	$134
	Medium Community Solar (LMI)	2,000	29%	100%	$118	$131	$141	$131	$141
	Large Community Solar (LMI)	5,000	29%	100%	$104	$116	$126	$116	$126
	Medium Commercial Roof Mount	250	8%	100%	$137	$151	$161	$141	$145
Ground Mounted	Medium Commercial Ground Mounted	500	2%	80%	$98	$115	$125	$111	$120
	Large Commercial Ground Mounted	1,000	4%	80%	$92	$105	$114	$102	$109
	Large Ground Mounted	5,000	11%	80%	$101	$98	$98	$99	$99
	Very Large Ground Mounted	10,000	83%	100%	$47	$67	$67	$67	$67

*The combined assumed market share of all Project Types in a given Incentive Group add to 100%. An average cost of entry value weighted by the TPO and host-owned share of projects by Project Type and these percentages of Project Types within Incentive Groups is used to calculate Incentive Group-Level costs of entry

The blended incentive gaps/costs of entry in Table 18 are the weighted average of the host owned results with the applicable TPO results.

Table 19 shows the weighted aggregated results of levelized incentive gap/cost of entry by Incentive Group. The <=25 kW Incentive Group is dominated (90%) by the Residential Roof Mount projects. The 15% discount results in Table 19 ($75/MWh) and 25% TPO discount offered ($90/MWh) are (given rounding) identical to the <=25 kW Incentive Group and for the Residential Roof Mount projects results provided in Table 18. The same effect can be observed in the blended incentive gap/cost of entry estimates for the constituents of other Incentive Groups as well.

Table 19 - TI-4 (15 yr, Base Cost) COE by NEM Discount and Incentive Group ($/MWh)

Incentive Group	15% NEM Discount for TPO	25% NEM Discount for TPO
Preferred Siting	$129	$131
Building Mounted	$115	$120
Community Solar	$129	$138
LMI	$126	$136
Ground Mounted	$73	$74
<=25 kW	$75	$90

Thus, the results in Table 18 and Table 19 make clear that the actual modeled TPO incentive requirements produce results that are highly similar (if not nearly identical to) to the results that industry stakeholders suggest are necessary to meet their offtakers' expectations. The Consulting Team recognizes that reasonable market participants could advocate for different (yet reasonable) approaches from what we describe herein. Indeed, some stakeholders are sure to continue to take issue with the Consulting Team's model assumptions and approach (e.g., Why not use JCP&L residential tariffs instead of PSEG as the proxy for the prototypical R-1 rate? Wouldn't it be better for each Incentive Group's incentive gap to be customized for each EDC? Why did you not model adders/subtractors? Why did you combine the Incentive Groups the way you did?). Unfortunately, not all sensitivities can be run to answer all questions because of the obvious reality of time and resource constraints, and because each service territory would not likely receive its own adjusted incentive. In the end, the modeling shown here and previously is a tool to help policy makers make informed decisions and should not be seen as the only potential basis for selecting an incentive value or values for the TI.

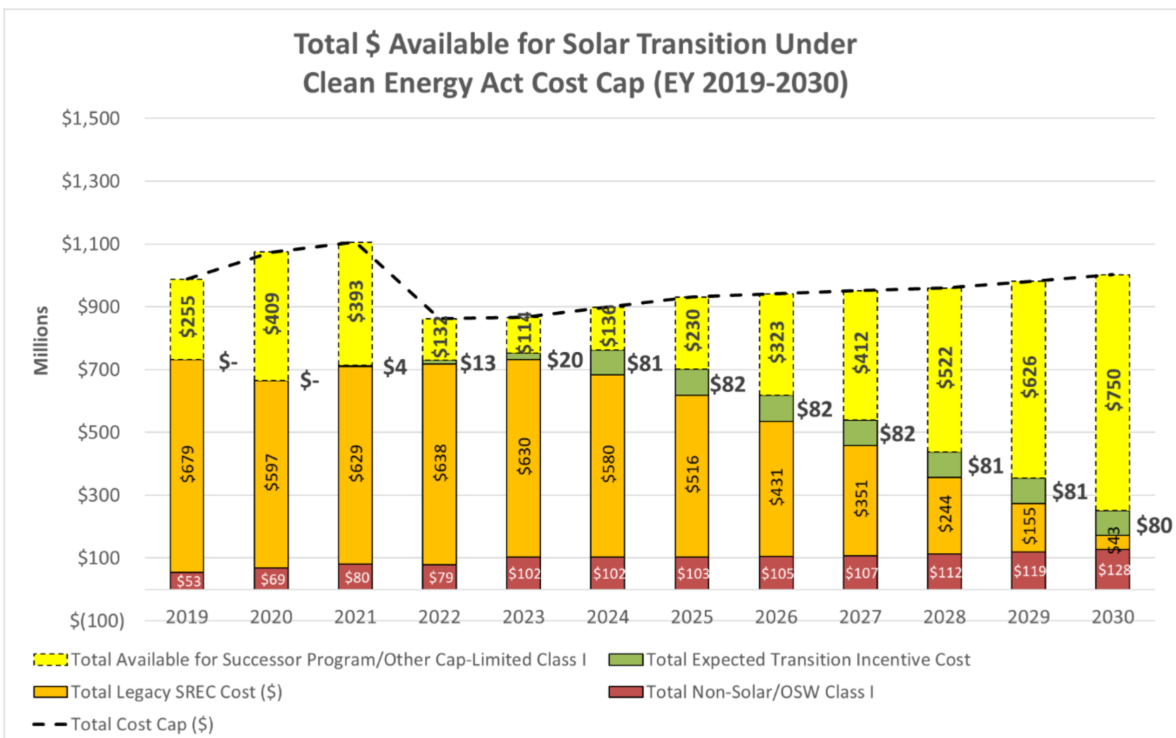
Finally, Table 20 displays the summary impact on the Cost Cap of the reference case with a 15% PPA discount and a sensitivity case with a 25% PPA discount. The 25% PPA discount is provided graphically for a Base Case Legacy SREC Price Outlook (Figure 7) and a High Case Legacy SREC Price Outlook (Figure 8). The impact versus the reference case (which assumes a 15% PPA discount) for Energy Year 2024 is relatively minor.

Conclusion: Overall, the Consulting Team believes that many of the differences stakeholders have expressed with the input assumptions of the TI analysis (e.g., project installed costs, capacity factor, and most notably here, the amount of discount provided by a TPO needed to induce offtaker participation) would result in modest but in many cases still significant changes in the modeled Incentive Gap revenue from the latest reference case for applicable Incentive Groups. Conversely, changes in methodological assumptions could have larger impacts on the Incentive Group level incentive gap results (e.g., calculating the incentive gap requirement for a Project Type at the TPO incentive requirement rather than at the weighted average of Project Type market share of the TPO and Host Owned results, as discussed above in this section and displayed in Table 18).

Table 20 – Change in Clean Energy Act Class I Cost Cap Headroom During EY 2024 by TI-4 NEM Discount (EY 2024, $ in Millions)

Cases and Sensitivities (Cost Profile & Incentive Term)	NEM Discount for TPO	Legacy SREC Price/ Cost Outlook	EY 2024 Cost Cap Headroom (7% Cap)
TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	15%	High	$62
TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	25%	High	$58

Figure 7 - Cost Cap Impact of TI-4 (Base Cost/15 Year, 25% NEM Discount) Under Base Case Legacy SREC Price Outlook



5.4. JCP&L Retail Rate Sensitivity

In our reference case model runs, we use the prototypical rate classes to assign retail rates to all Project Types that are assumed to be eligible to net meter. As discussed above, the PSEG modeled prototypical retail rates are, by a large margin, the lowest of any EDC for the small commercial and medium / large commercial rate classes (G-1 and G-2 – see Table 16). Conversely, the prototypical PSEG residential rate class value (rate class R-1) is the second lowest of any EDC for 2019 but still somewhat higher than the JCP&L modeled retail rate for 2019 (nominal 17.55 ₵/kWh for PSEG versus 14.26 ₵/kWh for JCP&L, see Table 16).

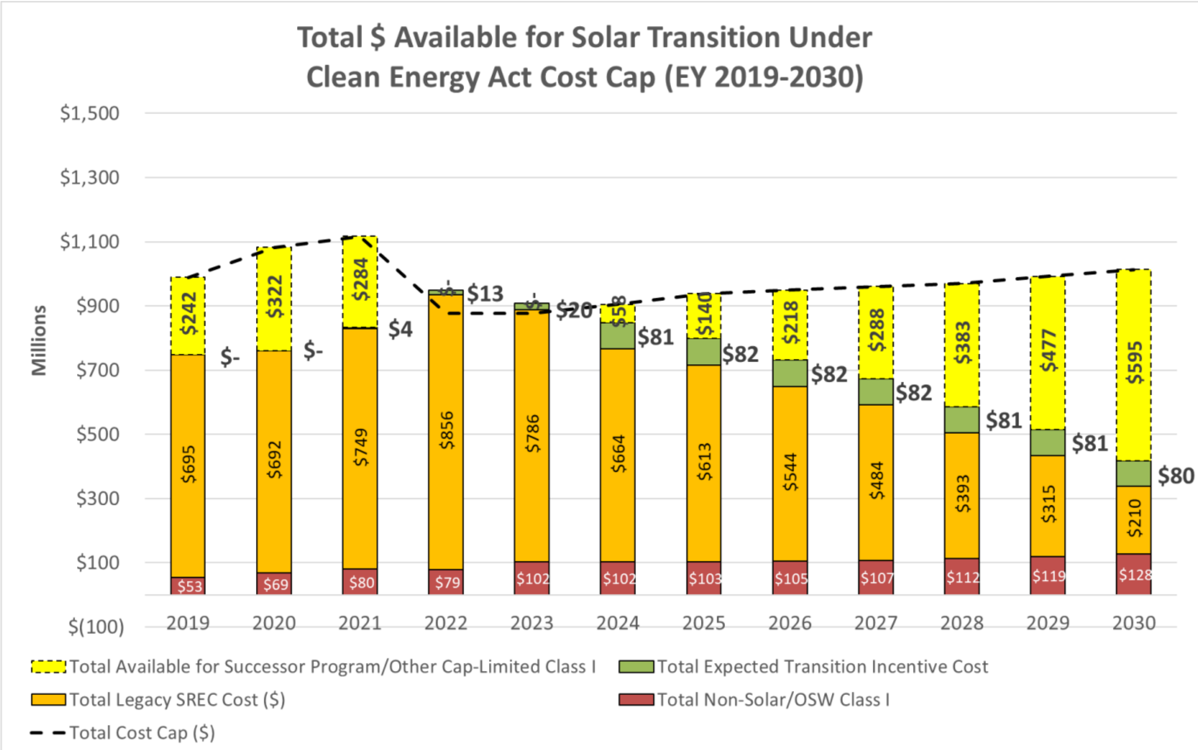
Table 21 contrasts each Incentive Group's COE for the modeled reference case (TI-4, 15-year incentive with Base Costs, PSEG retail rates) with a sensitivity in which JCP&L's retail rates are utilized. As can be seen in Table 21, all the Incentive Groups that are comprised of solely non-residential rate classes (i.e., all Incentive Groups except for the <=25 kW Incentive Group) have substantially lower COE incentive gaps if JCP&L is chosen as the EDC Retail Rate Proxy versus if PSEG is chosen as the EDC Retail Rate Proxy. Conversely, for the <=25 kW Incentive Group, choosing JCP&L as the EDC Retail Rate Proxy moderately increases the COE incentive gap.

Table 21 - TI-4 (15 yr, Base Cost) COE by EDC Retail Rate Proxy Discount and Incentive Group ($/MWh)

Incentive Group	PSEG as EDC Retail Rate Proxy	JCP&L as EDC Retail Rate Proxy
Preferred Siting	$129	$92
Building Mounted	$115	$30
Community Solar	$129	$30
LMI[17]	$126	$8
Ground Mounted	$73	$68
<=25 kW	$75	$103

[17] The LMI results are sharply lower in JCP&L territory relative to the Community Solar results, because all the Project Types in that Incentive Group are assumed to receive small-to-medium C&I rates. On the other hand, one of the Project Types in the Community Solar class (specifically, the Very Large Building Mounted Community Solar) receives a small-to-medium C&I rate, which is substantially lower than the large C&I rate. That produces a larger incentive gap in both JCP&L and PSE&G territories, which causes the values to diverge when JCP&L rates are assumed.

Figure 8 - Cost Cap Impact of TI-4 (Base Cost/15 Year, 25% NEM Discount) Under High Case Legacy SREC Price Outlook



Major implications of choosing PSEG as the EDC Retail Rate Proxy are as follows:

- All other things being equal and apart from Grid Supply projects (whose revenue is decoupled from retail rates), the calculated incentive gap will be larger than the actual required revenue for non-residential projects by a modest to wide margin for projects sited in the Atlantic City Electric, JCP&L, and Rockland Electric service territories.
- All other things being equal, the calculated incentive gap will be larger than the actual required revenue for residential rooftop projects by a modest margin for projects sited in the Atlantic City Electric and Rockland Electric service territories but be deficient by a modest margin for residential rooftop projects sited in the JCP&L service territory.

This inequity arising from differences in tariff rates across the four EDCs could be addressed by customizing TI incentives by EDC, but with the obvious consequence of making the TI program implementation more complicated.

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CADMUS

A. Comparison of Initial and Revised Upfront Capital Cost Assumptions

Project Type	Modeled System Size (kW)	Low Cost Case ($/kW)		Base Cost Case ($/kW)		High Cost Case ($/kW)	
		25th Percentile (Previous)	30th Percentile (New)	37.5th Percentile (Previous)	50th Percentile (New)	50th Percentile (Previous)	70th Percentile (New)
Residential Roof Mount	6.5	$2,724	$2,900	$3,071	$3,326	$3,326	$3,709
Small Commercial Roof Mount	13.2	$2,724	$2,900	$3,071	$3,326	$3,326	$3,709
Medium Commercial Roof Mount	250	$2,100	$2,200	$2,240	$2,377	$2,377	$2,978
Medium Commercial Roof Mount (LMI)	250	$2,150	$2,250	$2,290	$2,427	$2,427	$3,028
Medium Commercial Lot Carport	250	$2,850	$2,950	$2,990	$3,127	$3,127	$3,728
Medium Commercial Building Mounted	500	$1,725	$1,796	$1,893	$2,010	$2,010	$2,384
Medium Commercial Ground Mounted	500	$1,725	$1,796	$1,893	$2,010	$2,010	$2,384
Large Commercial Building Mounted	1000	$1,640	$1,700	$1,789	$1,968	$1,968	$2,325
Large Commercial Ground Mounted	1000	$1,640	$1,700	$1,789	$1,968	$1,968	$2,325
Large Commercial/Campus Lot Carport	1000	$2,390	$2,450	$2,539	$2,718	$2,718	$3,075
Small Landfill/Brownfield	1000	$1,717	$1,781	$1,870	$2,057	$2,049	$2,424
Small Community Solar	1000	$1,740	$1,800	$1,889	$2,068	$2,068	$2,425
Small Community Solar (LMI)	1000	$1,790	$1,850	$1,939	$2,118	$2,118	$2,475
Very Large Building Mounted	2000	$1,710	$1,753	$1,805	$2,000	$2,000	$2,400
Very Large Building Mounted Community Solar	2000	$1,810	$1,853	$1,905	$2,100	$2,100	$2,500
Very Large Carport	2000	$2,460	$2,503	$2,555	$2,750	$2,750	$3,150
Medium Community Solar	2000	$1,810	$1,853	$1,905	$2,100	$2,100	$2,500
Medium Community Solar (LMI)	2000	$1,860	$1,903	$1,955	$2,150	$2,150	$2,550
Large Community Solar	5000	$1,810	$1,853	$1,905	$2,100	$2,100	$2,500
Large Community Solar (LMI)	5000	$1,860	$1,903	$1,955	$2,150	$2,150	$2,550
Large Landfill/Brownfield	5000	$1,964	$2,014	$2,060	$2,285	$2,275	$2,735
Large Ground Mounted	5000	$1,710	$1,753	$1,805	$2,000	$2,000	$2,400
Very Large Ground Mounted (Fixed Tilt)	10000	$1,550	$1,559	$1,572	$1,594	$1,632	$1,678

Note: Capital cost includes interconnection costs. Community Solar, LMI, Carport and Landfill/Brownfield projects have cost adders applied to reflect the added costs of developing these Project Types.

B. Installed Cost Premia/Adders for Specialty Project Types

Project Category	Adder
Carports	$750/kW added to cost of typical project in size category
Community Shared Solar (CS)	$100/kW added to cost of typical project in size category
Low/Moderate Income (LMI) On-Site Solar	$50/kW added to cost of typical project in size category
LMI CS	$150/kW added to cost of typical project in size category
Small Landfill/Brownfield	5% increase from cost of typical project in size category
Large Landfill/Brownfield	15% increase from cost of typical project in size category

C. Comparison of Initial and Proposed Market Share of Third Party Owned Projects

Project Type	% Third Party Ownership (Initial)	% Third Party Ownership (Revised)
Residential Roof Mount	73%	63%
Small Commercial Roof Mount	73%	63%
Medium Commercial Roof Mount	48%	42%
Medium Commercial Roof Mount (LMI)	100%	100%
Medium Commercial Lot Carport	48%	42%
Medium Commercial Building Mounted	58%	43%
Medium Commercial Ground Mounted	80%	80%
Large Commercial Building Mounted	52%	41%
Large Commercial Ground Mounted	80%	80%
Large Commercial/Campus Lot Carport	52%	41%
Small Landfill/Brownfield	100%	100%
Small Community Solar	100%	100%
Small Community Solar (LMI)	100%	100%
Very Large Building Mounted	65%	65%
Very Large Building Mounted Community Solar	95%	95%
Very Large Carport	65%	65%
Medium Community Solar	100%	100%
Medium Community Solar (LMI)	100%	100%
Large Community Solar	100%	100%
Large Community Solar (LMI)	100%	100%
Large Landfill/Brownfield	100%	100%
Large Ground Mounted	80%	80%
Very Large Ground Mounted (Fixed Tilt)	100%	100%

Note: Updated values compared to modeling in the initial TI report are flagged in red and represent the share of TPO systems in the SRP Pipeline Report released July 2019. Values that are not updated are set based on project characteristics and the Consulting Team's understanding of the market and are assumed because the SRP reports do not categorize projects as granularly as the above-listed Project Types used in the modeling.

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D. Assumed Tilt and Azimuth Assumptions by Project Type

Modeled Size (kW_{DC})	Block Name	Characterization of Siting/Design	Tilt Approach	Tilt	Azimuth Approach	Azimuth	Array Type
6.5	Residential Roof Mount	Materially imperfect azimuth/tilt	Latitude of Trenton NJ +5 degrees	45.21	Shifted -22.5 degrees from due south	157.5	Fixed (roof mount)
13.2	Small Commercial Roof Mount	Materially imperfect azimuth/tilt	Latitude of Trenton NJ +5 degrees	45.21	Shifted -22.5 degrees from due south	157.5	Fixed (roof mount)
250	Medium Commercial Roof Mount	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
250	Medium Commercial Roof Mount (LMI)	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
250	Medium Commercial Lot Carport	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
500	Medium Commercial Building Mounted	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
500	Medium Commercial Ground Mounted	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
1000	Large Commercial Building Mounted	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ Less 5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
1000	Large Commercial Ground Mounted	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
1000	Large Commercial/ Campus Lot Carport	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ Less 5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
1000	Small Landfill/ Brownfield	Imperfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Shifted -22.5 degrees from due south	157.5	Fixed (roof mount)
1000	Small Community Solar	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
1000	Small Community Solar (LMI)	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
2000	Very Large Building Mounted	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
2000	Very Large Building Mounted Community Solar	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
2000	Very Large Carport	Slightly Imperfect flatter roof mount	Latitude of Trenton NJ -5 degrees	35.21	Shifted +22.5 degrees from due south	202.5	Fixed (roof mount)
2000	Medium Community Solar	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
2000	Medium Community Solar (LMI)	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
5000	Large Community Solar	Perfect Ground Mount	At Latitude (Trenton,	40.21	Due South	180	Fixed (open rack)

Modeled Size (kW_{DC})	Block Name	Characterization of Siting/Design	Tilt Approach	Tilt	Azimuth Approach	Azimuth	Array Type
			NJ)				
5000	Large Community Solar (LMI)	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
5000	Large Landfill/Brownfield	Imperfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Shifted -22.5 degrees from due south	157.5	Fixed (open rack)
5000	Large Ground Mounted	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)
10000	Very Large Ground Mounted (Fixed Tilt)	Perfect Ground Mount	At Latitude (Trenton, NJ)	40.21	Due South	180	Fixed (open rack)

E. Derivation of Revised <=25 kW Year 1 Capacity Factor

Variable	<=25 kW Year 1 Capacity Factor
Value from PVWatts (used in TI report)	15.30%
Actual PJM GATS analysis attached to Straw Proposal (used in 9/6 Sensitivity Analysis)	13.80%*
Average (To Be Used Going Forward for <=25 kW Incentive Group)	**14.55%**

*Value represents an assumed Year 1 value, based on production from 2014-2018, and assuming an annual degradation factor of 0.5%