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STATE OF NEW JERSEY
Board of Public Utilities
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NOTICE[1]

New Jersey Solar Transition

Revised 2019/2020 Transition Incentive Staff Straw Proposal

and Modeling Addendum

Pursuant to the "Open Public Meetings Act", N.J.S.A. 10:4-6 et seq., the New Jersey Board of Public Utilities ("BPU") hereby gives notice of a Public Meeting to discuss the below Revised 2019/2020 NJ Solar Transition Incentive Staff Straw Proposal and Modeling Addendum ("Revised Staff Straw Proposal" or "Revised TI Straw").

For convenience, changes to the Staff Straw Proposal compared to the version issued on August 22, 2019 are identified via a yellow highlight.

The Clean Energy Act of 2018 ("Act") requires the BPU 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 the closure of the SREC market upon the State's attainment of 5.1% of kilowatt hours sold from solar electric generation facilities. In implementation of the Act, the BPU has engaged a consultant and is leading a Solar Transition process, including measures to close the current SREC Program ("Legacy SREC Program") and design a successor solar incentive mechanism ("Successor Program"). This Revised TI Straw addresses the need for an incentive program, the "Transition Incentive," which bridges the gap between the Legacy and Successor Programs.

On December 26, 2018, Staff of the BPU released a New Jersey Solar Transition Staff Straw Proposal ("December Straw Proposal") which included a schedule for the development of the Solar Transition, notice of two stakeholder meetings, and a request for stakeholder comments. The December Straw Proposal requested comments on solar transition principles and the

[1]Not a Paid Legal Advertisement

development of a successor to the SREC program. Comments were also sought on the incentive requirements of transition projects, namely those in the SREC pipeline but incomplete at the time the Board determines to close the SREC market to new registrations. On April 8, 2019, Board Staff issued a stakeholder notice ("April 2019 Notice") which announced three stakeholder workshops to be organized by the Solar Transition Consultants (Cadmus and Sustainable Energy Advantage). The second Consultant Stakeholder Workshop, held on June 14, 2019, focused specifically on eliciting stakeholder feedback on potential policy design options for the Transition Incentive. Board Staff has greatly appreciated the input and comments provided by stakeholders throughout this process.

On August 22, 2019, BPU Staff issued the 2019/2020 Transition Incentive Staff Straw Proposal ("2019/2020 TI Straw Proposal"), which included questions for public comment.

To further inform stakeholder feedback, Staff published as attachments to the Straw Proposal two documents:

1. The New Jersey Transition Incentive Supporting Analysis & Recommendations drafted by the Solar Transition Consultant.
2. The New Jersey Solar Performance Analysis prepared by the PJM-EIS Generation Attribute Tracking System.

A webinar was held on Friday August 23, 2019, where Staff presented the 2019/2020 TI Straw Proposal to stakeholders and addressed comments.

Stakeholder Meeting #1 was held Wednesday August 28, 2019 at the New Jersey War Memorial, in Trenton, NJ. The stakeholder meeting included a panel discussion comprised of representative stakeholders, moderated by BPU Staff. Stakeholders were provided the opportunity to ask questions to the panel, as well as to provide formal oral comments.

Stakeholder Meeting #2 was held Wednesday September 4, 2019 at the Cook College Student Center, Rutgers University in New Brunswick, NJ. This stakeholder meeting also included a panel discussion comprised of representative stakeholders, moderated by BPU Staff. Stakeholders were also provided the opportunity to ask questions to the panel, as well as to provide formal oral comments.

A third Stakeholder Meeting was held on Friday September 6, 2019 in the Board's multipurpose room at 44 South Clinton Avenue in Trenton, NJ. This stakeholder meeting was attended by the Board's consultant and addressed the modeling and assumptions used in the Transition Incentive Supporting Analysis & Recommendations. Based on this meeting, the consultant identified an error in the model and at the request of Staff adjusted certain assumptions before fixing the error and rerunning the model. The consultant's report titled Addendum to Transition Incentive Supporting Analysis & Recommendations ("Modeling Addendum") issued as an Appendix to this Notice presents the revised model results. The modeling changes are described in Section 2 of the Modeling Addendum (pp. 10 -13). Staff notes that Table 1 and 2 within this revised Straw include the updated model results that are now the subject of this Request for Public Comment.

Stakeholders are directed to the New Jersey Clean Energy Program website for background materials, including Board Orders and rules, on the NJ Solar Transition at http://njcleanenergy.com/renewable-energy/program-updates-and-background-information/solar-proceedings.

Informed by stakeholder feedback and the Consultant's analysis, Board Staff is therefore issuing the following Revised TI Straw and associated questions for public comments. Staff is also releasing the Modeling Addendum developed by the Solar Transition Consultant as an attachment to this notice.

In order to continue dialogue with stakeholders, Staff is planning to hold an additional Stakeholder Meetings to receive feedback on this Revised TI Straw and Modeling Addendum, as well as an opportunity to address the questions contained herein in writing.

Stakeholders wishing to participate must register no later than 5:00 p.m. on Thursday, October 10, 2019 via an email to solar.transitions@bpu.nj.gov.

Date: Friday, October 11, 2019

Location: New Jersey Department of Environmental Protection
Hearing Room
401 E State St, Trenton, NJ 08608

Time: 10 a.m.

Staff requests that stakeholders interested in addressing issues related to the development of the Successor Program clearly state which comments are related to Transition Incentive issues and which are related to the Successor Program. Staff is working toward having a Successor Program ready to follow the Legacy SREC and Transition Incentive when the Board determines that the 5.1% milestone has been attained. Opportunities for stakeholder engagement on the Successor Program will commence in October 2019 and a workshop will be scheduled in November 2019. The Solar Consultants' modeling of Successor Program alternatives is anticipated to conclude in December 2019, after which time a Staff Straw Proposal on the Successor Program will be issued.

Written comments are also encouraged and should address the questions posed by Staff and reference the associated question by number. 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.

All comments must be received on or before **5:00 p.m. on October 18, 2019** in order to be considered. 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

Date: October 3, 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 Consultants retained by Board Staff. The report, titled "New Jersey Transition Incentive Supporting Analysis & Recommendations" and prepared by the Solar Transition Consultants, as well as its Modeling Addendum are attached to this Straw Proposal.

Proposal for the Structure of the Transition Incentive

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).

Eligible Project Options

[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.L. 2018, c. 17. (Rule Proposal).

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 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.

[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.

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 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. Modeled TI-ACP Schedules to Account for Cost Cap (drawn from Consultant Report Modeling Addendum)

ACP Schedules by Scenario/Sensitivity

Scenarios/Sensitivities	Cost Profile & Incentive Term	"Kink" Period			Post-"Kink" Period													
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
TI-2a - DO w/SREC Factors	Base Cost - 15 Year	$150	$135	$122	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$0
TI-3 - DO w/SREC Factors & Firmed Hedge Option	Base Cost - 15 Year	$65	$59	$53	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$0
TI-4 - Partial Long-Term Hedge	Base Cost - 15 Year	$65	$59	$53	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189	$0
TI-4 - Partial Long-Term Hedge	Base Cost - 20 Year	$65	$59	$53	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164
TI-4 - Partial Long-Term Hedge	Low Cost - 20 Year	$65	$59	$53	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119
TI-4 - Partial Long-Term Hedge	Base Cost - 10 Year	$65	$59	$53	$257	$257	$257	$257	$257	$257	$257	$257	$0	$0	$0	$0	$0	$0
TI-4 - Partial Long-Term Hedge	High Cost - 10 Year	$65	$59	$53	$370	$370	$370	$370	$370	$370	$370	$370	$0	$0	$0	$0	$0	$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 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**	**0.5**	**0.5**

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 Solar 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.

Revised Questions to Stakeholders

General Structure of the proposed Transition Incentive

1) What are the potential advantages and challenges of Staff's proposed Transition Incentive design?
2) What are the advantages and challenges to the two approaches; a fixed price TREC and a market based TREC?
3) Does the proposed Revised Transition Incentive provide sufficient financial surety for projects currently in the SRP pipeline that may not reach commercial operations prior to the closure of the SREC market to new entrants?
4) How can the Board most accurately predict the amount of capacity expected to be in the SRP pipeline at the time the 5.1% Milestone is hit? During what timeframe in the transition process, would a final determination of the size of the pipeline of eligible projects be required? Should there be a true-up?

Eligibility

5) How should the Board treat projects entering the SRP pipeline that have not 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?
6) Should the Board cease accepting new registrations to the SREC Registration Program, and begin only accepting registrations to a new Transition Incentive cluster?

Terms for each TREC

7) Please discuss the proposed 15-year TREC term, with appropriate justification for any recommended changes.

Value of a TREC

8) Are the TI-ACP schedules proposed in Revised Table 1 to be associated with each compliance entity option appropriate? If modifications are required, how should the schedules be adjusted and why?
9) Please critique the proposal of a "custom" TI-ACP which is relatively low in EY21, EY22 and EY23 and increases thereafter, keeping in mind the statutory cost cap the program must operate under.
10) What are the implications of establishing a "Buyer of Last Resort" and floor price mechanism for the TREC market? What factors should Staff consider in recommending how a purchase price is established?
11) When and how should a floor price be established to provide the maximum benefit to ratepayers, developers, investors?
12) Would the availability of a floor price above the NJ Class I ACP provide any reduction in finance costs for eligible projects?

Factorization of TRECs

13) Do you agree with the proposed categories of factors (Revised Table 2)? Why or why not?
14) Please address the financial incentive levels for each of the four project types.
15) Do you agree with the proposed assigned factors? Why or why not? Please provide documented explanations for your response.

Compliance Entities

16) Please discuss the advantages and disadvantages of the two proposed options, i.e. having the compliance entities be: 1) Third Party Suppliers and Basic Generation Service Providers, or 2) the Electric Distribution Companies.
17) Which of the two options is preferable for the Transition Incentive?
18) Do parties agree that a fixed price TREC lends itself to the EDCs serving as the compliance entity, while a market-based price for TRECs lends itself to the TPS/BGS Providers serving as the compliance entity?

Written comments are also encouraged and should address the questions posed by Staff and reference the associated question by number. 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.

All comments must be received **on or before 5:00 p.m. on October 18, 2019**. 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.

Issued: August 22, 2019
Revised: October 3, 2019

Sustainable Energy Advantage, LLC

CADMUS

Addendum to Transition Incentive Supporting Analysis & Recommendations

September 25, 2019

Prepared for:

New Jersey Board of Public Utilities

44 South Clinton Avenue

9th Floor

Trenton, NJ 08625-0350

Prepared by:
Sustainable Energy Advantage, LLC
Cadmus, Inc.

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Figures

1. Introduction

1.1. Transition Incentive Stakeholder Process to Date

On August 23, 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 also issued a companion report issued by Sustainable Energy Advantage, LLC and Cadmus, Inc. (collectively, the "Consulting Team") entitled *New Jersey Transition Incentive Supporting Analysis & Recommendations* (hereafter referred to as "TI report"). The BPU also issued Appendixes and substantiating spreadsheets developed by the Consulting Team to further inform the TI report. The analysis in the report informed BPU Staff's development of the Staff Straw Proposal.

In the 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 <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 report);
- A demand obligation <u>with</u> a Buyer of Last Resort (assumed to be New Jersey's electric distribution companies). 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 report); and
- A purchase program for TRECs at a fixed payment rate (analogous to Policy Path TI-4 analyzed in the report).

In doing so, BPU eliminated some alternatives examined in the Report, specifically, Policy Paths TI-1a and TI-1b (a demand obligation without either TREC Factors or a Buyer of Last Resort) and Policy Path TI-2b (a demand obligation 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 report reflects analysis undertaken by the Consulting Team over a period from January 2019 to July 2019. The assumptions that went into the 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 that was vetted by the BPU, 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, 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. Prior to these sessions, the assumptions were discussed with BPU Staff, documented, and vetted by BPU Staff for use prior to analysis and modeling being undertaken.

Following the concurrent release of the Staff Straw Proposal and the TI report, the BPU offered three 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.

In addition, while responding to stakeholder questions regarding some of the assumptions following the Technical Session, the Consulting Team identified and corrected two specific programming errors that impacted the estimated revenue gap used to establish proposed incentive values.

1.2. Purpose of Report Addendum

There is extensive industry experience with successful establishment of effective incentive levels for renewable energy performance-based incentives - balancing the many objectives including ratepayer cost minimization and project viability - through a transparent stakeholder engagement process that includes presentation and review of assumptions and results, consideration of stakeholder feedback, and potential refinement of key policy and market assumptions when merited.[1] 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 the incentive levels, associated cost to ratepayers, and Cost Cap impacts associated with the TI-2a, TI-3 and TI-4 policy types, as well as four new sensitivities on the TI-4 policy type. Table 1 below compares the different policy cases analyzed in the initial report and the Report Addendum.

[1] The Consulting Team has extensive experience with such process 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 DG Standard Contracts (DGSC) and Renewable Energy Growth (REG) programs.

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	TI Report Addendum
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		✓

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 do so with a hedged purchase option included (TI-3), and also consider other steps that would encourage participation in such a hedged purchase option 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. 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 SREC Registration Program (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.[2] 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 don't have the flexibility to reduce costs without requiring renegotiating their current counter-party agreement.

[2] 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 percentile spread (i.e., 70th and 30th percentile) for the Low and High Cost Cases for this TI Addendum modeling analysis.[3] 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,[4] 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% is attained, 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 have been installed to date.[5]
- **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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[3] 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% attainment (thereby corresponding with cost percentile in the High Cost case).

[4] 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.

[5] 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 (which note whether the project is a carport project, a community solar project, a landfill or brownfield project, 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 range of costs, as well as higher financing costs (and thus larger incentive requirements).

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 up to and including 25 kW would *on average* regularly be sited in conditions producing materially imperfect azimuths and tilts, as 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 far 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-idea siting conditions, overestimate production relative to what is occurring in practice as a result of as variety of factors. Such factors sited by solar stakeholders include:
  - The average *in practice* configuration (e.g., tilt, azimuth, shading, losses) were 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 generation 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,[6] the revised Consulting Team approach effectively splits the difference, taking the midpoint between the PVWatts modeled

[6] 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 baked in thus skewing the capacity factors lower than what would be expected for Year 1 production.

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 (in analogous engagements) modeled a discount to retail rates for all project model "blocks" assumed to be receiving offtake from a third party-owned entity, in order to represent the effects of the prevalent market practice of a project owner offering a discount to a project's offtaker. In effect, this discount factor 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:** While these errors did not reflect a methodological choice, they 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 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. However, as detailed in Section 3.2, this reduction in the incentive gap/cost of entry was offset by the other changes discussed in this Section.

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. These revised results include:

- Weighted Average Levelized Incentive Gaps in PSEG territory;
- Recommended TREC Factors[7];
- 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 purchases a project's TRECs at "(a) pre-established floor price could be established that ensures **a contribution to a return on investment** for eligible transition projects" (emphasis added).[8] 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 participant voluntary 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

[7] 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). They are then rounded and aggregated as inputs for calculating the ratepayer and cost cap impacts (see Table 5 below). The Consulting Team proposed the use of TREC Factors that have been rounded and aggregated in Table 5.

[8] 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

Resort if the market is short. However, the results would be comparable if the market is in surplus.

- **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 to after the expiration of the TREC's life (which in many cases occurs after the "Kink" period). [9]
- **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

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 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
	As Revised	**$158**	**$168**	**$140**	**$138**	**$84**	**$92**
	Change (Δ) from Initial	**$17**	**$27**	**$27**	**$28**	**$0**	**$60**
TI-3 & TI-4 - Partial Long-Term Hedge	Initial	$128	$127	$103	$99	$74	$10
	As Revised	**$144**	**$152**	**$129**	**$126**	**$75**	**$69**

[9] Related to the points just made, the in practice 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 the fraction of TRECs used during their normal lifetime to comply with the TREC requirements for load serving entities plus the TRECs that take advantage of the floor price option upon expiration.

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Analysis Vintage	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
(Base Cost, 15 Year)	**Δ from Initial**	**$16**	**$25**	**$26**	**$27**	**$1**	**$59**

- **Variation Between Reference Policy Cases:** The increases in incentive gap/cost of entry estimates are largely uniform across policy types but are slightly lower ($1-$2/MWh per Incentive Group) for TI-3 and TI-4.
- **<=25 kW Projects:** Incentive requirements for <=25 kW projects increased by $60/MWh compared to the initial analysis, driven in roughly equivalent proportion by the increase in assumed installed cost percentiles, the decrease in assumed capacity factor, and including the 15% TPO discount. Overall, given its higher installed costs (and wider distribution of costs between the low, base, and high cost cases) the <=25 kW Incentive Group is more sensitive to changes in inputs, resulting in larger shifts in Cost of Entry. While some other Project Types have comparable variance to the <=25 kW Project Types, the Consulting Team derived incentive values for non-<=25 kW Incentive Groups by taking a weighted average of Project Types across multiple size bins. As a result, Project Types with high variance in installed cost are combined with Project Types with lower variance, resulting in less variance for the Incentive Group compared to the <=25 kW Incentive Group which only has two Project Types both less than <=25 kW (i.e., Residential Roof Mount 6.5 kW and Small Commercial Roof Mount 13.2 kW, see Appendix A).

- **Shift in Relative Magnitude of Building Mounted and Preferred Siting Groups:** The Building Mounted Incentive Group now has the highest incentive requirement, and thus sets the TACP in the TI-2a, the hedged buyback price in TI-3, and the Fixed TREC price in TI-4 policy cases. However, as the incentive levels needed are relatively close for the Building Mounted and Preferred Siting Incentive Groups, to keep uniformity with the Staff Straw Proposal and to encourage development on non-greenfield sites we have recommended assigning both Building Mounted and Preferred Siting projects a TREC value of 1.00.
- **Limited Change in Ground Mounted Incentive Group:** Relative to other Incentive Groups, the values for Ground Mounted projects were less sensitive to modeled changes. This is a result of the Consulting Team assigning a Very Large Ground Mounted Project Type an 83% weight within the group's weighted average cost of entry (COE). This weighting anchored the Ground Mounted Incentive Group's weighted average COE because the Very Large Ground Mounted Project Type had a relatively small change in its base case installed cost as a result of the updated cost inputs (see Appendix A). The Ground Mounted Incentive Group contains many larger Project Types that have significant fixed costs associated with them (e.g., land lease, project management, PILOT agreements). As a result, a smaller component of these Project Types' total costs varies when we switch between cost cases. In addition, the TPO and host-

owned market shares for Ground Mounted projects did not change from the initial analysis. Finally, the Ground Mounted category is assumed to be dominated (94%) by projects that do not receive net metering service, so the newly-applied 15% TPO PPA discount has limited impact for that category.

- In the higher cost cases (TI-2a (Base Cost/15 Year) and TI-4 (High Cost/10 Year)), costs for <=25 kW projects rise above those of Ground Mounted projects, which can be explained by the wider <=25 kW cost variance and smaller Ground Mount cost variance discussed above.

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.

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*	*$144*	*$152*	*$129*	*$126*	*$75*	*$69*
High Cost/10 Year	Sensitivity	$241	$255	$213	$210	$123	$161
	Δ from Main TI-4 Case	**$97**	**$103**	**$84**	**$84**	**$48**	**$92**
Base Cost/10 Year	Sensitivity	$175	$184	$159	$154	$92	$87
	Δ from Main TI-4 Case	**$31**	**$32**	**$30**	**$28**	**$17**	**$18**
Base Cost/20 Year	Sensitivity	$130	$139	$116	$113	$68	$61
	Δ from Main TI-4 Case	**($14)**	**($13)**	**($13)**	**($13)**	**($7)**	**($8)**
Low Cost/20 Year	Sensitivity	$95	$105	$87	$84	$50	$11
	Δ from Main TI-4 Case	**($49)**	**($47)**	**($42)**	**($42)**	**($25)**	**($58)**

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;
- Providing incentives at 70th percentile with a 10-year term has largest impact on the calculated incentive gap/cost of entry ($31-$74/MWh), whereas reducing the term to 10 years from 15 reduces incentive gaps by $17-$31/MWh; and
- Shortening the incentive term increases incentive gaps/costs of entry substantially more than lengthening the term increases them.

3.3. Recommended TREC Factors/Fractional Fixed TREC Payments

Following BPU Staff's consultations with stakeholders and the development of the incentive gap/cost of entry figures discussed in Section 3.2 above, the Consulting Team propose the following revised TREC Factors for the reference 15 Year, Base Cost policy cases.

Table 4 - TREC Factors by Reference Policy Option

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 Year)	Initial	1.00	1.00	0.80	0.78	0.59	0.23
	As Revised	**1.00**	**1.00**	**0.85**	**0.85**	**0.5**	**0.55**
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
	As Revised	**1.00**	**1.00**	**0.85**	**0.85**	**0.5**	**0.45**

The major changes to the TREC Factors, and shown in Table 4, include:

- Raising the factors for Community Solar and LMI projects to 0.85;
- Increasing the <=25 kW factor (to reflect the increase in expected incentive gap/cost of entry) to 0.55 for the TI-2a case and 0.45 for the TI-3 and TI-4 cases; and
- Reducing the Ground Mounted factor (which reflects the ratio of the weighted average Ground Mounted incentive gap/cost of entry, but still reflects an increase in expected incentive gap/cost of entry) to 0.5 in all cases.

Like the increased incentive gap/cost of entry figures, the overall impact of this change is to increase both the value of TRECs under all cases, as well as increase the overall cost to ratepayers of the Transition Incentive.

The Consulting Team also proposed modeling Fixed TREC Factors for a TI-4 sensitivity analysis (as shown in Table 5 below).

Table 5 – Newly Proposed 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	1.00	0.85	0.85	0.50	0.45
High Cost, 10 Year	1.00	1.00	0.85	0.85	0.50	0.60
Base Cost, 10 Year	1.00	1.00	0.85	0.85	0.50	0.50
Base Cost, 20 Year	1.00	1.00	0.85	0.85	0.50	0.55
Low Cost - 20 Year	1.00	1.00	0.85	0.85	0.50	0.10

Relative to the reference TI-4 15-year, Base Cost case, only the <=25 kW TREC Factor changes. The changes are consistent with variations in the term of the incentive and the assumed underlying installed costs for distributed solar projects. Overall, and as with the incentive gap/cost of entry figures, the assumed underlying installed costs vary much more widely for <=25 kW projects, producing large swings in the assumed TREC Factor by TI-4 sensitivity.

3.4. Net Present Value of Ratepayer Cost

Using the revised estimates of revenue per TREC, as multiplied by the amount of TREC capacity and production estimated in the initial report, the Consulting Team calculated the following (see Table 6) revised net present value (NPV) estimates for the reference TI policy cases:

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

Case/Sensitivity	Ratepayer NPV (Initial Analysis, $MM)	Ratepayer NPV (As Revised, $MM)	Δ ($MM)
TI-2a - DO w/TREC Factors (Base Cost -15 Year)	$800	**$921**	**$121**
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	$594-$800†	**$691-$921†**	**$97-$121**
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	$566	**$658**	**$92**
†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 an additional $92-$121 million (as shown in Table 6). Like both the TREC Factors and incentive gap/cost of entry figures, NPVs for all cases have risen as a result of the changes in assumptions discussed in Section 2. However, the nearly $30 million greater rise in NPV of TI-2a (the market-based TREC policy type) compared to TI-4 reflects the added uncertainty associated with price formation in such a market design relative to TI-4 (in which market participants hedge their revenue stream at a fixed price). Depending upon how TI-3 is implemented and received by the market, it 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 to Ratepayers ($MM)
TI-4 – Partial Long-Term Hedge (Low Cost - 20 Year)	**$498**
TI-4 - Partial Long-Term Hedge (Base Cost -10 Year)	**$645**
TI-4 – Partial Long-Term Hedge (Base Cost - 20 Year)	**$683**
TI-4 - Partial Long-Term Hedge (High Cost - 10 Year)	**$917**

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. However, as Table 7 above shows, the spread between the lowest cost ($498 million) and highest cost

($917 million) sensitivities is nearly equivalent to the total cost of the lowest cost option (which provides a longer term 20 year – and thus higher NPV – incentive than one of shorter duration).

3.5. 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 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 sufficient headroom during the "Kink" period has served (and will continue to serve) as both a complementary and superseding 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 ACP".[10] 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. As shown in Table 8 below, with that model constraint in place, increases in overall TI incentive levels also boost required post-Kink period revenue for TI projects. While (as Table 9 also shows) adopting a Low Cost or 20 Year incentive framework can mitigate this pressure on post-Kink costs to ratepayers on an annual basis, such options also come with the tradeoffs of increased risk of high levels of TI project attrition (because of the lower assumed costs) and higher ratepayer NPVs (because of the longer term), 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
	As Revised	**$75**	**$67**	**$61**	**$266**
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost/15 Year)	Initial	$65	$59	$53	$155
	As Revised	**$65**	**$59**	**$53**	**$189**
TI-4 - Partial Long-Term	Initial	$65	$59	$53	**$155**

[10] 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.

Case/Sensitivity	Analysis Vintage	EY 2021 (9% Cap)	EY 2022 (7% Cap)	EY 2023 (7% Cap)	EY 2024 & After (7% Cap)
Hedge (Base Cost/15 Year)	**As Revised**	**$65**	**$59**	**$53**	**$189**

Table 9 - Initial & 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*	*$189*
Base Cost/20 Year	**$65**	**$59**	**$53**	**$164**
Low Cost/20 Year	**$65**	**$59**	**$53**	**$119**
Base Cost/10 Year	**$65**	**$59**	**$53**	**$257**
High Cost/10 Year	**$65**	**$59**	**$53**	**$370**

Thus, as shown in Table 10 (with TI-4 sensitivities similarly displayed in Table 11), the (relatively) higher ratepayer cost policy options (such as TI-2a, or shorter-duration, higher-cost TI-4 sensitivities) run a risk of breaching the Cost Cap in Energy Year 2024.[11] In practice, the newly required incentive levels, combined with the incentives provided in EYs 2021-2023 means that Cost Cap in EY 2024 becomes a new potential choke point that could cause the Cost Cap to be breached in higher-cost policy cases (in effect extending the Kink period an additional year). [12]

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
		Revised	**$9**
		Δ from Initial	**($18)**
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost/15 Year)	High	*Initial*	$45
		Revised	**$43**
		Δ from Initial	**($2)**
TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	High	*Initial*	*$61*
		Revised	**$47**
		Δ from Initial	**($14)**

[11] While all the cases but the High Cost/10 Year case indicate available Cost Cap headroom in EY 2024, we estimate that New Jersey's "total paid for electricity" will reach $13 billion (nominal) in EY 2024, leaving a very narrow margin for error.

[12] Our initial TI Report analysis, the Kink period was assumed to be from the beginning of EY 2022 to the end of EY 2023, when the Legacy SREC program is expected to cost the most for New Jersey ratepayers.

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*	*$47*
		Sensitivity	($41)
		Δ from TI-4 Base Case	**($88)**
Base Cost/10 Year	High	*Revised TI-4 Base Case*	*$47*
		Sensitivity	**$14**
		Δ from TI-4 Base Case	**($34)**
Base Cost/20 Year	High	*Revised TI-4 Base Case*	*$47*
		Sensitivity	**$59**
		Δ from TI-4 Base Case	**$12**
Low Cost/20 Year	High	*Revised TI-4 Base Case*	*$47*
		Sensitivity	**$81**
		Δ from TI-4 Base Case	**$34**

Overall, these results suggest that adopting the increased Base Case incentive levels modeled in this Report Addendum would make adoption of a Fixed TREC design more crucial to mitigate the risk of breaching the Cost Cap (assuming no further changes to the Legacy SREC program). For example, adopting TI-2a with the higher incentive values (as shown in Table 10) would drive EY 2024 headroom to under $10 million of dollars, substantially increasing the risk of breaching the Cost Cap. In fact, as shown in Table 11, adopting High Cost installed cost assumptions for modeling the value of the TREC could drive headroom to -$41 million in EY 2024. In effect, both these dynamics could have the effect of extending, rather than mitigating, the Kink period.

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/SREC Factors) Under Base Case Legacy SREC Price Outlook

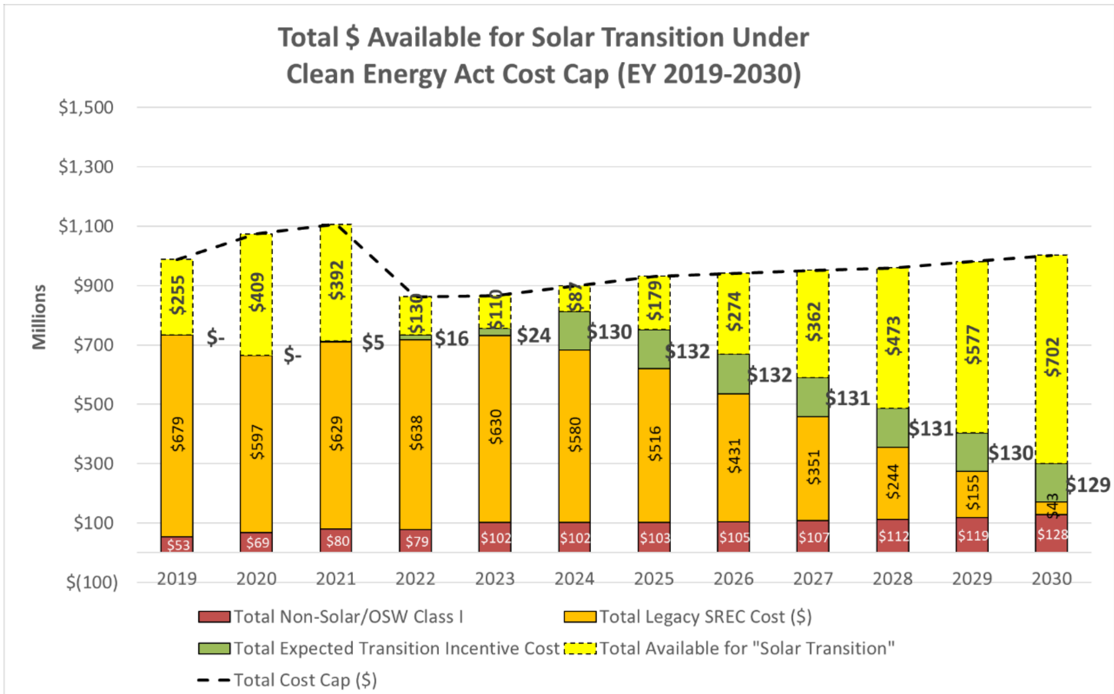


Figure 2 – Cost Cap Impact of Base Cost/15 Year TI-2a (DO w/SREC Factors) Under High Case Legacy SREC Price Outlook

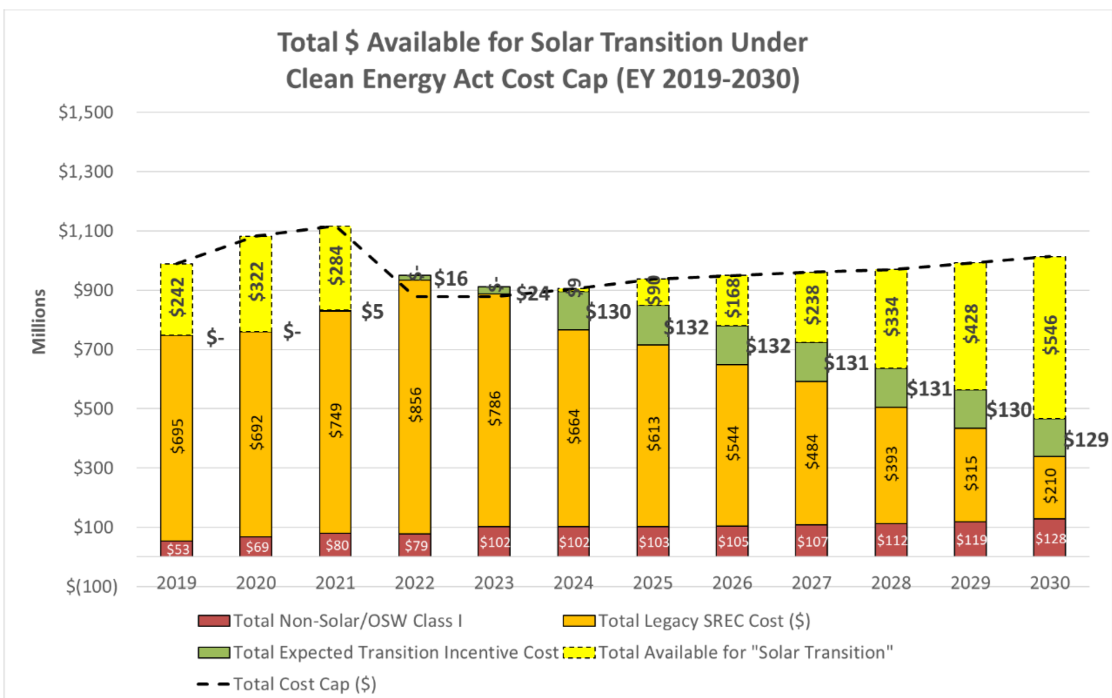


Figure 3 – Cost Cap Impact of Base Cost/15 Year TI-3 (DO w/TREC Factors & Firmed Hedge Option) Under Base Case Legacy SREC Price Outlook

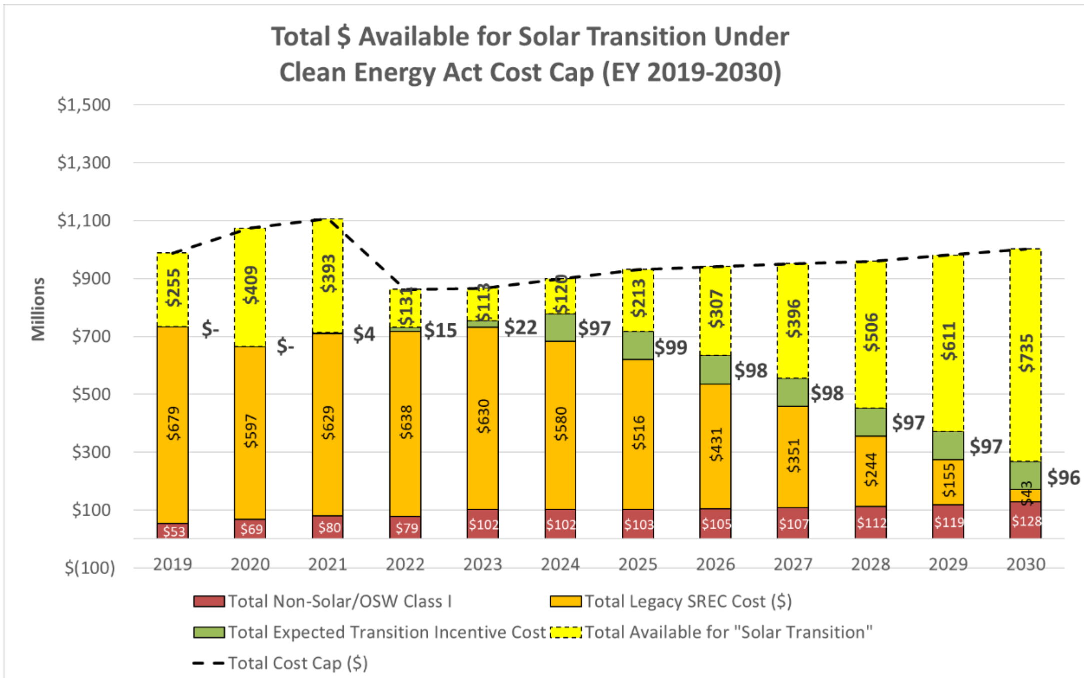


Figure 4 – Cost Cap Impact of Base Cost/15 Year TI-3 (DO w/TREC Factors & Firmed Hedge Option) Under High Case Legacy SREC Price Outlook

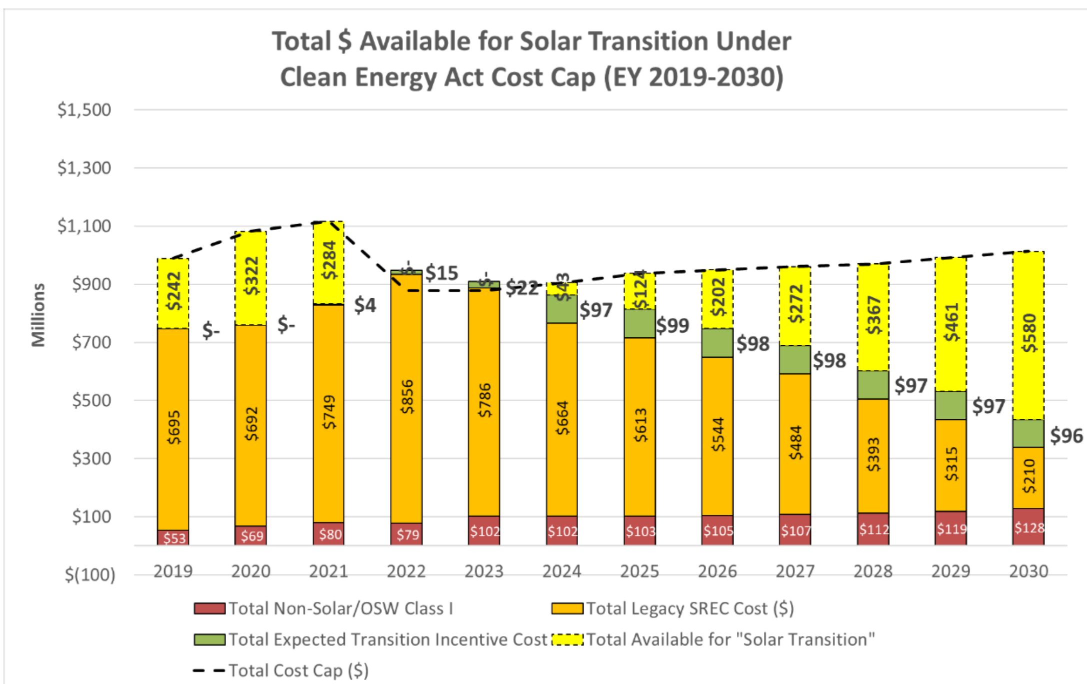


Figure 5 - Cost Cap Impact of Base Cost/15 Year TI-4 (Partial Long-Term Hedge) Under Base Case Legacy SREC Price Outlook

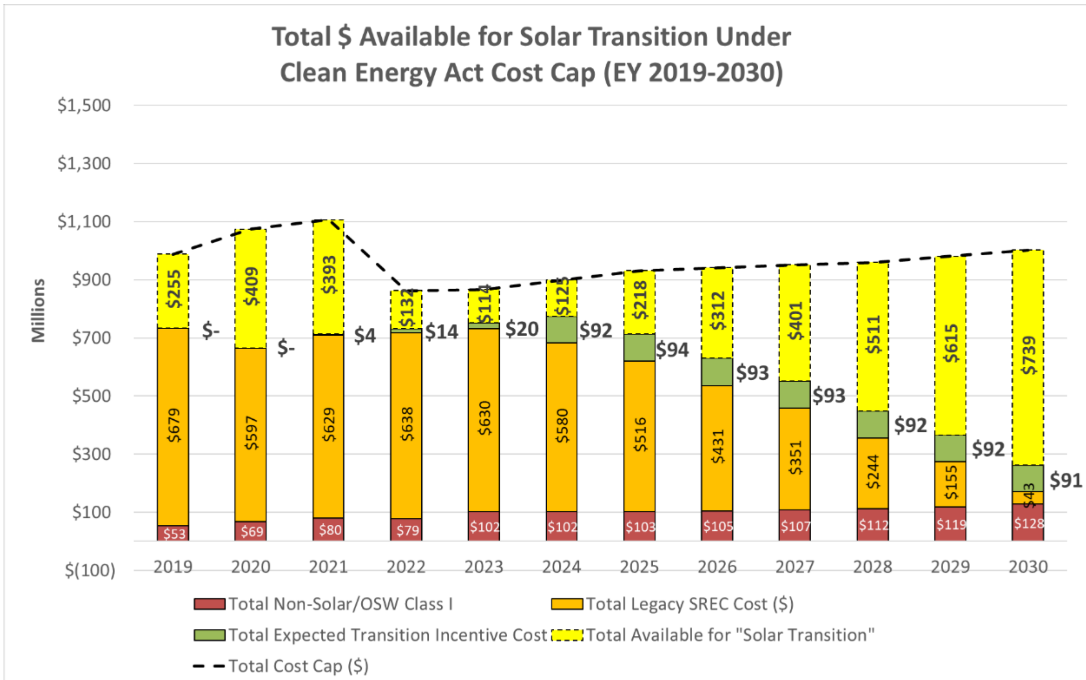
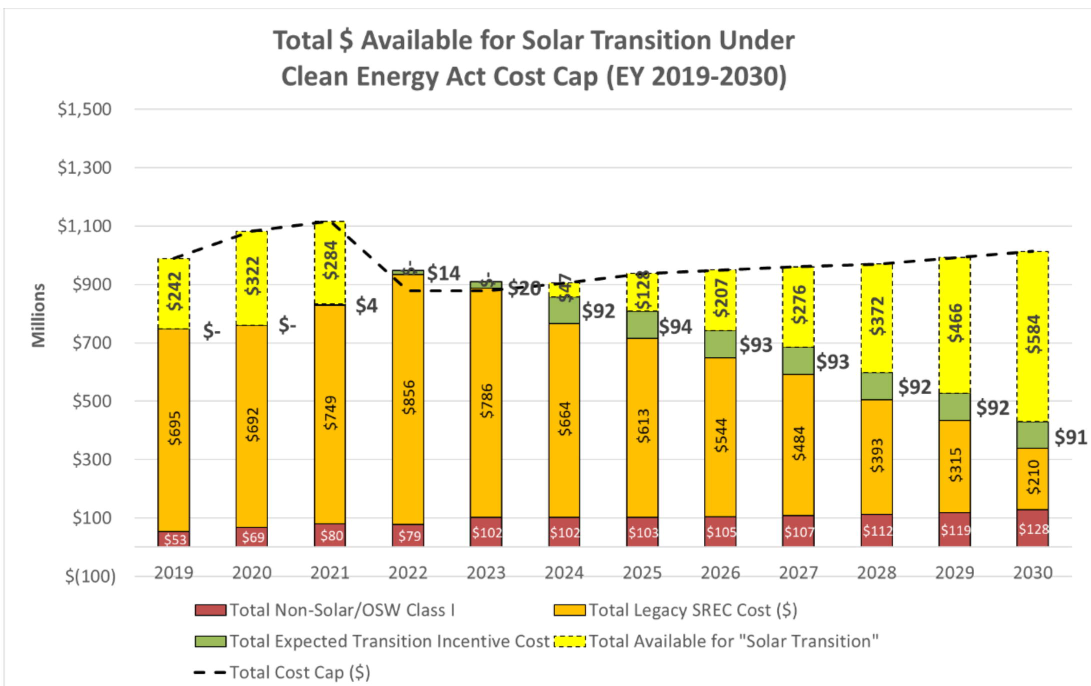


Figure 6 - Cost Cap Impact of Base Cost/15 Year TI-4 (Partial Long-Term Hedge) Under High Case Legacy SREC Price Outlook



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

One of modeled 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%*
	As Revised	**$131**	**$116**	**$160**	**22%**	**38%**
TI-3 & TI-4 - Partial Long-Term Hedge (Base Cost/15 Year)	*Initial*	$130	$115	*$100*	*-23%*	*-13%*
	As Revised	**$130**	**$115**	**$117**	**-10%**	**2%**

*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 substantially more expensive to ratepayers than the Legacy SREC program (assuming that the Consulting Team's modeling assumptions for Legacy SREC program costs (and Legacy SREC prices) are accurate. In addition, options that allow voluntary (TI-3) and

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

required (TI-4) hedged EDC purchases have a lower cost to ratepayers than Legacy SREC projects likely to reach commercial operation in 2019, but not for those reaching commercial operation in 2020.[14]

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

Cost Profile & Incentive Term	Metric	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	*As Revised*	*$130*	*$115*	*$117*	*-10%*	*2%*
High Cost/ 10 Year	As Revised	**$130**	**$115**	**$196**	**51%**	**71%**
Base Cost/ 10 Year	As Revised	**$130**	**$115**	**$141**	**8%**	**23%**
Base Cost/ 20 Year	As Revised	**$130**	**$115**	**$107**	**-18%**	**-7%**
Low Cost/ 20 Year	As Revised	**$130**	**$115**	**$79**	**-39%**	**-31%**

*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. Similar to the cost of entry results, project cost assumptions have the greatest impact on the assumed levelized revenue. Specifically, assuming High Cost parameters (70th percentile of upfront capital costs in the market) would increase costs substantially beyond the Consulting Team's estimate of Base Case Legacy SREC revenue (+51% to +71%). 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.

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[14] For the initial TI report (and 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, and while it is not as substantial as the assumed solar PV cost profile, 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 substantially 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. Conversely, extending the term is much more likely to result in a TI incentive that costs less on a $/MWh basis than a project coming online under the Legacy SREC program. However, a key tradeoff of extending the term of the incentive is that (all other factors being equal) increases the NPV of the cost to ratepayers, given that a greater incentive value is paid out over a longer period.

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)	$47	1	TI-4 - Partial Long-Term Hedge (Base Cost, 15 Year)	**$658**
2	TI-3 - DO w/TREC Factors and Firmed Hedge Option (Base Cost, 15 Year)	**$43**	2	TI-3 - DO w/TREC Factors and Firmed Hedge Option (Base Cost, 15 Year)	**$691-$921**
3	TI-2a - DO w/TREC Factors (Base Cost, 15 Years)	**$9**	3	TI-2a - DO w/TREC Factors (Base Cost, 15 Years, As Revised)	**$921**
†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%20Transition%20Stakeholder%20Notice%202019-04-08-19.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 Reference Policy Cases 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	**$82**	1	Low Cost/20 Year	**$498**
2	Base Cost/20 Year	**$59**	2	Base Cost/10 Year	**$645**
3	Base Cost/10 Year	**$14**	3	Base Cost/20 Year	**$683**
4	High Cost/10 Year	**($41)**	4	High Cost/10 Year	**$917**
†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 3.5, 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)

At Stakeholder Workshop #2 held in Trenton, NJ on June 14, 2019, most solar stakeholders suggested they wanted to make only incremental changes to the current structure given their perception of the limited time until the 5.1% threshold is attained, requiring closure of the Legacy SREC program. However, accommodating the increased incentive values proposed herein (undertaken in part to address concerns raised by many of the same solar stakeholders) while simultaneously limiting ratepayer cost and avoiding Cost Cap breach suggests that the incremental improvements to the status quo proposed in TI-2a appears to be an increasingly difficult balance to achieve.

Thus, the Consulting Team recommends adoption of a Fixed 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

The results in this Report Addendum make clear that after the TREC valuation option under consideration, the assumed PV cost case is the next most significant determinant of ratepayer cost and Cost Cap exposure. 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 recommends setting Base Costs at the 50^{th} percentile Base Case in order to mitigate 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, the Base Cost/20 Year approach would increase ratepayer exposure by $25 million relative to Base Cost/15 Year, but would also provide $12 million in added EY 2024 Cost Cap headroom. Thus, the Consulting Team recommends adoption of either a 15- or 20-year TI term.

A. Comparison of Initial and Revised Upfront Capital Cost Assumptions

Project Type	Modeled System Size (kW)	Low Cost Case ($/kW) 25th Percentile (Previous)	Low Cost Case ($/kW) 30th Percentile (New)	Base Cost Case ($/kW) 37.5th Percentile (Previous)	Base Cost Case ($/kW) 50th Percentile (New)	High Cost Case ($/kW) 50th Percentile (Previous)	High Cost Case ($/kW) 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- to Moderate-income (LMI) 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 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	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, NJ)	40.21	Due South	180	Fixed (open rack)
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%