*UPDATED – August 28, 2019
**UPDATED – September 03, 2019

Philip D. Murphy
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STATE OF NEW JERSEY

Board of Public Utilities
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NOTICE[1]

New Jersey Solar Transition 2019/2020 Transition Incentive Staff Straw Proposal

***Stakeholder Process-Comment Period Extension**
****Notice of Additional Stakeholder Meeting**

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 two Public Meetings to discuss the below 2019/2020 NJ Solar Transition Incentive Staff Straw Proposal ("Straw Proposal" or "TI Straw").

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 TI Straw addresses the need for an incentive program which bridges the gap between the Legacy and Successor Programs (the "Transition Incentive").

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 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

[1]Not a Paid Legal Advertisement

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.

Informed by stakeholder feedback and the Consultant's analysis, Board Staff is issuing the following Straw Proposal and associated questions for public comments.

To further inform stakeholder feedback, Staff is publishing as addendums 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.

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.

In order to continue dialogue with stakeholders, Staff is planning to hold one webinar and two Stakeholder Meetings to receive feedback on this Transition Incentive Straw Proposal, as well as an opportunity to address the questions contained herein in writing.

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.

The webinar will be held on Friday, August 23, 2019, at 10:00 a.m. To access the webinar, please use the following link from your computer or smartphone:

https://global.gotomeeting.com/join/487340221

You can also dial in using your phone.
United States: +1 (786) 535-3211
Access Code: 487-340-221

Note: This webinar can only accommodate the first 150 participants to enter the webinar. If the attendee limit is exceeded, stakeholders wishing to participate in the webinar will still be able to call in to the number above. Additionally, any slides used during the webinar will be posted on the Clean Energy Program website shortly before the beginning of the webinar, so as to allow all participants to follow along.

Stakeholder Meeting #1 will be held:

Date: Wednesday, August 28, 2019

Location: Trenton War Memorial
1 Memorial Drive, Trenton, NJ 08608

Time: 10:00 a.m. – 2:00 p.m.

Note: this stakeholder meeting will include a panel discussion comprised of representative stakeholders, moderated by BPU Staff. Stakeholders will have the opportunity to ask questions to the panel, as well as to provide formal oral comments. This meeting will be recorded by a court reporter. Stakeholders interested in attending must register no later than noon on Tuesday, August 27, 2019 via an email to solar.transitions@bpu.nj.gov.

Stakeholder Meeting #2 will be held:

Date: Wednesday, September 4, 2019

Location: Cook College Student Center, Rutgers University
59 Biel Road, New Brunswick, NJ 08901

Time: 10:00 a.m. – 2:00 p.m.

Note: this stakeholder meeting will include a panel discussion comprised of representative stakeholders, moderated by BPU Staff. Stakeholders will have the opportunity to ask questions to the panel, as well as to provide formal oral comments. This meeting will be recorded by a court reporter. Stakeholders interested in attending must register no later than noon on Tuesday, September 3, 2019 via an email to solar.transitions@bpu.nj.gov.

****An additional stakeholder meeting will be held** to discuss modeling assumptions with the Solar Transition Consultant and BPU staff. Stakeholders wishing to participate must register no later than 5:00 p.m. on Thursday, September 5, via an email to solar.transitions@bpu.nj.gov.

Date: Friday, September 6, 2019

Location: 44 South Clinton Avenue, Trenton, NJ 08625

Time: 10:00 a.m. – 12:00 p.m.

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.

Written comments were due to be submitted by September 6, 2019, however the comment submission period has been extended to ***September 13, 2019**. All comments must be received on or before 5:00 p.m. on ***September 13, 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
Secretary of the Board

Dated: September 4, 2019

2019/2020 Transition Incentive Staff Straw Proposal

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 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, is 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 revenues for various installation types. In each case, the goal of the factorization program is to ensure that ratepayers are providing the appropriate 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

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.

[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 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]

Mechanism for Creation of TRECs

Staff proposes that a TREC would be created based upon metered generation supplied to PJM-EIS 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 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"); at which time projects may be eligible for a NJ Class I REC.

Value of a TREC Options

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

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

[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.

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.

Table 1. Modeled TI-ACP Schedules to Account for Cost Cap (drawn from Consultant Report)

TI-ACP Schedules by Scenario/Sensitivity

Scenarios/Sensitivities	"Kink" Period			Post-"Kink" Period											
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
TI-2a - DO w/TREC Factors	$320	$288	$259	$719	$719	$719	$719	$719	$719	$719	$719	$719	$719	$719	$719
TI-2b - DO w/ TREC Factors & Perpetually Short Design	$90	$81	$73	$244	$244	$244	$244	$244	$244	$244	$244	$244	$244	$244	$244
TI-3 - DO w/TREC Factors & Firmed Hedge Option	$65	$59	$53	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155
TI-4 - Partial Long-Term Hedge	$65	$59	$53	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155

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 could 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.

Table 2. Project Type Factors Expressed as Multipliers

Project Type	Net Metered Projects (<=25 kW)	Ground Mounted (Grid Supply & NM >25 kW)	Community Solar	Preferred Siting: Subsection t, Grid Supply Rooftop and Carport
	TREC - NM	TREC - GM	TREC – CS	TREC - PS
Compliance Factor	0.2	0.6	0.8	1

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. For example, in Value Option #1 where TRECs are procured in a competitive market, TRECs from projects that meet the Preferred Siting criteria would be valued by regulated compliance entities five times greater than small net metered projects. TRECs generated from this type of project would receive a price below the TI-ACP (i.e., from Table 1. Option TI-2a: a price less than $244 per TREC in EY2024). Since small net metered projects receive significantly higher retail value for the electricity produced, the TRECs generated will receive one-fifth of the value of a TREC produced from the Preferred Siting category. In turn, regulated compliance entities would receive five times the value for TRECs procured from projects qualifying as Preferred Siting.

In Value Option #2, where TRECs are provided a fixed price, TRECs from projects that meet the Preferred Siting criteria would also be valued by regulated compliance entities five times greater than small net metered projects. TRECs generated from this type of project would receive the price at the ACP (From Table 1. Option TI-3: $155 per TREC in EY24). Since small net metered projects receive significantly higher retail value for the electricity produced, the TRECs generated would receive one-fifth of the value of a TREC produced from the Preferred Siting category. Regulated compliance entities would receive five times the value for TRECs procured from projects qualifying as Preferred Siting.

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 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 and Ground Mount[4] projects fall somewhere in between, and thus, under a factorization proposal, would receive an intermediate subsidy.

<u>Compliance Entities in the TI-RPS Options</u>

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 Electric Suppliers ("TPS") and Basic Generation Service ("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

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[4] Note that certain ground mount projects also qualify for net metering, but are generally ineligible to offset the demand charges associated with customers of greater than 25 kW.

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.

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 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 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? 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 Electric 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 September 6, 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.

Sustainable Energy Advantage, LLC

CADMUS

Transition Incentive Supporting Analysis & Recommendations

July 5, 2019 (Revised July 19, 2019 and August 14, 2019)

Prepared for:

New Jersey Board of Public Utilities

44 South Clinton Avenue

3rd Floor, Suite 314

CN 350

Trenton, NJ 08625-0350

Prepared by:

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Executive Summary

This Transition Incentive Supporting Analysis & Recommendations Report comprises part of the scope of consulting services that Sustainable Energy Advantage (SEA) and Cadmus (the "Consulting Team") are providing to the BPU under the Assessment and Recommendation for Redesign of Solar Renewable Energy Certificate Program. This report builds upon analysis conducted with guidance of BPU Office of Clean Energy (OCE) staff and feedback from stakeholders.

Stakeholder engagement was conducted via phone interviews, formal surveying, email comments, inquiries, and two stakeholder workshops organized on May 2, 2019 in New Brunswick (SWS1) and June 14, 2019 in Newark (SWS2).

In line with the goals of the Clean Energy Act of 2018, the New Jersey Board of Public Utilities is moving to develop a Solar Transition, comprised of a Transition Incentive (TI) and an eventual Successor Program (SP), to replace the Legacy SREC program once total solar generation reaches 5.1% of state retail load. In implementing a Solar Transition, it is necessary to develop programs that avoid breach of the Class I RPS Cost Caps (particularly during the "Kink" period of Energy Years 2022 and 2023, when such caps phase down to 7% of the "total paid for electricity"), and that can be implemented in the time prior to attaining the 5.1% threshold at which the Legacy SREC program must close. To meet these objectives, the Consulting team developed several policy options for the TI, ranging from options that mainly preserve the SREC status quo, to a fixed performance-based incentive (PBI) for environmental attributes, and several other variants in between.

After careful consideration, the Consulting team recommends developing a TI that has several characteristics of the current SREC program, but also includes 'factorization' of the Transition Incentive Renewable Energy Certificates ("TRECs") generated by eligible systems. These factors serve as a means of scaling these incentives to the underlying incentive revenue requirement of various distributed solar PV project types (thereby saving money for New Jersey ratepayers relative to the status quo). In addition, to avoid breaching the Cost Cap during the Kink period, the Consulting team also recommends providing these TRECs over a 20-year period.

Report Structure and Methodology

The report is organized into three sections: Section 1 reviews the Consulting Team's development of options for the TI, including underlying assumptions, guiding principles, constraints, and methodology for choosing a final set of TI options for analysis; Section 2 reviews the Consulting Team's analysis of the TI options, including modeling assumptions and results; and Section 3 ranks the options, discusses issues with implementation and implications for the Successor Program, and provides recommendations to the BPU Staff for choosing a TI. Following are key takeaways from each section.

Section 1: Transition Incentive Option Development

In determining a viable set of TI options, the Consulting Team relied on a set of guiding principles, its strong understanding of incentive design and feasibility, recognized constraints, and stakeholder feedback.

The report assumes the following regarding a potential TI:

- The Clean Energy Act of 2018 (Clean Energy Act), as written, sets the bounds of what can be considered for a policy response, including the establishment of a cap on the cost for ratepayers of Class I renewable energy resources;
- The Solar Transition Principles provided in the Staff Straw Proposal issued December 26, 2018 (Staff Straw Proposal) and repeated in the Staff Stakeholder Notice issued April 8, 2019 (April Notice) provide appropriate principles for analysis and adoption of a viable TI.
- Any project qualified via the SRP unable to qualify under the Legacy SREC program will be automatically registered for the TI. The Successor Program would begin when the transition point has been deemed to have occurred—i.e., when it is deemed 5.1% of the New Jersey retail load has been met by solar generation. While the methodology for calculating attainment of the transition point is yet to be finalized, modeling in this Report leads to an assumption that the 5.1% milestone will be reached around September 2020.[1]

Section 1 provides an extensive recounting of the policy path development and stakeholder engagement that resulted in the TI options analyzed, ranked and recommended herein.

Section 2: Analysis & Modeling of Selected Transition Incentive Options

The four policy path descriptions (presented at the June 14 Stakeholder Workshop, and as shown in Table 6 in the body of the report) that are the basis for the policy paths modeled for this analysis are:

- TI-1, a Demand Obligation (DO), Transition Incentive Renewable Energy Certificate (TREC) program that approximates the status quo, with no significant features intended to reduce ratepayer cost;

[1] See Footnote **Error! Bookmark not defined.** in the main body of the report.

- TI-2, a TREC program resembling the status quo but utilizing Factorized TRECs (i.e., fractions of an SREC for different classifications of projects);
- TI-3, a TREC program with both Factorized TRECs and the option to receive a fixed payment for TRECs generated; and,
- TI-4, offering fixed TREC payments differentiated by market segment.

To analyze the overall ratepayer cost and Cost Cap impact of each of the above options, the Consulting Team developed forecasts and estimates of:

- Legacy SREC production and 5.1% transition point attainment;
- Legacy SREC pricing scenarios based on Base Case, High Supply/Low Demand and Low Supply/High Demand through Energy Year 2033 (EY 2033, the final year of the program);
- Eligible TI capacity in the Legacy SREC pipeline at the 5.1% transition point (which we forecast to be no greater than 529 MW_{DC} including de-rates to capture the "scrub rate");
- The "total paid for electricity" through Energy Year 2054 (in order to calculate the Class I Cost Cap through the full 25-year assumed life of distributed solar projects reaching commercial operation through EY2030);
- The total required incentive for the development of solar projects in New Jersey, defined as the expected gaps between (i) the cost of developing, financing and deploying various types of distributed solar projects through calendar year 2030 over their useful lives (also referred to as "cost of entry"), and (ii) the non-New Jersey incentive revenues that such projects can expect from retail rates, net metering credits (or PJM energy and capacity payments) and federal tax incentives; and
- Total required Transition Incentive Alternative Compliance Payments (TI-ACPs) (or incentive levels, if provided on a fixed basis) needed to ensure deployment of distributed solar projects.

The methodology and results associated with these forecasts and estimates can be found in Attachments 1 and 2, as well as in Table 10 through Table 17 in the main body of the report. Per the discussion and findings in Section 1, the Consulting Team, in consultation with BPU Staff, chose six policy paths for more in-depth modeling and analysis (which are summarized in Table 7 the body of the report). These approaches offer 15-year, Base Cost incentives, and are described in detail in report Section 2.2. Below is a description of each option, as well as its associated direct ratepayer cost, its impact on the Cost Cap, and issues associated with its implementation as a transitional incentive.

TI-1a (Demand Obligation[2] w/ Flat TI-ACP) and TI-1b (DO w/ Custom TI-ACP): TI-1a represents a reference case, as the closest analogue to the current SREC legacy program. TI-1b represents a variation

[2] A demand obligation-based design has a total demand for RECs, SRECs or TRECs, with market-based means to meet demand. The NJ SREC program is a demand obligation-based design.

of TI-1a, as it employs a custom TI-ACP that is reduced during EYs 2021-2023 (the "Kink" period[3]) to navigate the Cost Cap, and conversely higher during the post-Kink years to ensure the NPV of the incentive fills project revenue gaps.

- *NPV of Direct Ratepayer Cost:* For these near-"status quo" cases, the cost to ratepayers ranges from **$907 million** for TI-1a to **$1.016 billion** for TI-1b, respectively. The difference in price results from higher assumed project revenues in the post-Kink period to compensate for lower SACPs during the Kink period.
- *Cost Cap Impact:* Under Base Case Legacy SREC prices, these policies result in Cost Cap headroom of $91-$125 million in EY 2022, and $45-$103 million in EY 2023. However, using a High Legacy SREC price results in a breach of the Cost Cap by a margin of **$78 -$111 million** in EY 2022, and **$42-$101 million** in EY 2023.
- *Implementation Issues:* While these structures would represent the least amount of structural change, we note that with any TREC/DO-based design, it remains difficult to set a Minimum Standard and Compliance Obligation that can create long-term supply-demand balance, or (in the case of TI-1b) to set Kink and post-Kink period STCPs that allow for appropriate investor return on TI-enabled projects. In addition, adopting an option similar to the status quo provides the greatest range of potential Successor Program options.

TI-2a (DO w/ Custom SACP and SREC Factors) and TI-2b (D.O. w/ Custom SACP, SREC Factors, and Perpetually Short Design): TI-2a is identical in structure to TI-1b - including the customized SACP structure - but also includes differentiated SREC Factors for projects with varying incentive gap amounts based on project type (see Table 16 for these specific factors by project type for the main policy path cases). TI-2b differs from TI-2a by establishing the Compliance Obligation at a level that is unattainable (in other words, such that the demand for SRECs would always exceed the supply). If financiers were convinced of that the market would remain short, SREC prices should theoretically remain high, and the program's SACP rate could be lowered while still ensuring sufficient solar project developer returns, thereby benefitting ratepayers.[4]

- *NPV of Direct Ratepayer Cost:* For these cases, the Consulting Team forecasts that the cost to ratepayers is in the range of **$701-$800 million**. The largest drivers of savings come from SREC factorization (which saves a minimum of **$107 million** relative to the TI-1 cases) and a reduced SACP in the case of TI-2b (which could enable an additional ratepayer savings of **$99 million**).
- *Cost Cap Impact:* Under Base Case Legacy SREC prices, these policies result in Cost Cap headroom of **$129-$130 million** in EY 2022 and **$109-$111 million** in EY 2023.Using a High

[3] For every option but TI-1b, the "Kink" period, if defined as the years in which the Cost Cap is most likely to be breached, is EY 2022-2023. However, we forecast a slight possibility for a breach in EY 2024 for TI-1b under a High SREC price scenario. In tables later in this analysis, we also include EY 2021 as a contrast between years in which the cap is 9% vs. 7% to show the drop in headroom when the cost cap is tightened.

[4] See Section 2.2 for more relevant details on this option.

Legacy SREC price case results in a breach of the Cost Cap by a margin of **$72-$73 million** in EY 2022 and **$34-$36 million** in EY 2023.

- *Implementation Issues:* Relative to the TI-1 options, the main implementation issues are associated with setting appropriate SREC Factors. In addition, implementing a perpetually short market design under case TI-2b in such a manner that excess SACP revenue can be returned to ratepayers poses a challenge – i.e., it is unlikely to be simple to implement in the relatively short period prior to expected TI rule adoption and implementation. The requirement to preserve a "perpetually short" market may also have a fatal flaw, in that it requires convincing financiers that future Boards would not countermand the intent of the perpetual short structure.

TI-2a (DO w/ Custom SACP and SREC) Sensitivities: Given that TI-2a is an option that balances incremental change relative to the status quo with ratepayer cost reductions, the Consulting Team also undertook the following four TI-2a sensitivity analyses to vary the underlying solar PV project cost profile used to set the incentives and length of the incentive term[5]:

- *Base Cost, 20-Year Incentive:* While adding 5 additional years to the term of the incentive adds approximately **$35 million** to the cost to ratepayers, it also creates approximately **$2-$3 million** in annual Cost Cap flexibility during EY 2022 and **$3-$4 million** in EY 2023 relative to the standard TI-2a cases (assuming either Base or High SREC prices).
- *Low Cost, 20-Year Incentive:* Adding 5 additional years to the term of the incentive, as well as setting incentives to compensate the lowest-cost quartile of projects in New Jersey, reduces the cost to ratepayers by **$161 million** relative to the standard TI-2a case, but does not create incremental Cost Cap flexibility relative to the Base Cost, 20-Year sensitivity (assuming either Base or High SREC prices).
- *Base Cost, 10-Year Incentive:* Reducing the term of the incentive by 5 years reduces the overall cost to ratepayers by **$72 million**, but increases the risk of breaching the Cost Cap, adding **$16 million** and **$23 million** against the Cost Cap in EY 2022 and EY 2023, respectively, relative to the standard TI-2a case (assuming either Base or High SREC prices).
- *High Cost, 10-Year incentives:* Reducing the term of the incentive by 5 years and using costs that reflect the median reported costs in New Jersey would both increase the total cost to ratepayers by **$147 million** and reduce Cost Cap flexibility by **$19 million** and **$27 million** in EY 2022 and EY 2023, respectively (assuming either Base or High SREC prices).

[5] The goal of this approach was to determine how varying the term or assumed cost profile might affect the NPV of ratepayer costs, or compliance with the Class I Cost Cap. The base case installed cost estimates were set at the 37.5th percentile of costs reported to the Solar Registration Program (to correct for potential upward bias in installer self-reported data) and varied by +/- 12.5 percentile points. See Attachment 1 for more details.

TI-3 (DO w/ Custom SACP, SREC Factors, and Firmed Hedge Option): This option is also identical in structure to TI-2a, except that under TI-3, the EDCs (or other entities) would develop programs offering a fixed payment in exchange for title to the SREC, in a form of fixed-for-floating swap.[6]

- *NPV of Direct Ratepayer Cost:* The Consulting Team forecasts that the cost to ratepayers would be in the range of **$594-$800 million**, depending on the percentage of projects that opt to receive a fixed payment for SRECs in exchange for title to the SRECs as opposed to selling their SRECs for the market price.
- *Cost Cap Impact:* Under Base Case Legacy SREC prices, this policy would, if 100% of the market participated, result in Cost Cap headroom of between **$131 million** in EY 2022 and **$112 million** in EY 2023. However, using a High Legacy SREC price case results in a breach of the Cost Cap by a margin of **$72 million** in EY 2022 and **$33 million** in EY 2023.
- *Implementation Issues:* While TI-3 can offer significant ratepayer benefits relative to the status quo, its implementation process (including receiving EDC and other stakeholder buy-in prior to TI rule adoption and implementation) may prove challenging.

TI-4 (Partial Long-Term Hedge): Under this option the EDCs would offer differentiated, fixed-premium payments in exchange for environmental attributes (such as RECs or SRECs) produced by the projects, thereby replacing the DO-based structure entirely.

- *NPV of Direct Ratepayer Cost:* The Consulting Team forecasts that the cost to ratepayers would be **$566 million**.
- *Cost Cap Impact:* Under Base Case Legacy SREC prices, this policy would result in Cost Cap headroom of between **$131 million** in EY 2022 and **$112 million** in EY 2023. However, using a High Legacy SREC price case results in a breach of the Cost Cap by a margin of **$72 million** in EY 2022 and **$33 million** in EY 2023.
- *Implementation Issues:* Implementation of this option in a timely manner may be challenging. Additionally, adopting a TI outside the DO approach may effectively foreclose (re)adoption of a DO-based approach for the Successor Program, given that a hedged incentive is a significant departure in program design from the current SREC program.

Section 3: Ranking and Recommendations of Transition Incentive Options

Table 20 and in the main body of the report include combined rankings of the main six TI options discussed above, based on criteria developed by the Consulting Team, in collaboration with stakeholders and BPU staff. Policy cases TI-2a and TI-2b are the most viable choices for the TI, as they provide ratepayer savings, can be implemented within a realistic timeframe, and received stakeholder support in

[6] A fixed-for-floating swap is a type of financial transaction where the seller would offer the buyer a guaranteed revenue stream in exchange for a market based (i.e., potentially volatile) revenue stream.

discussions during the June 14 Stakeholder Workshop. Of these two options, we recommend TI-2a, with a 20-year TREC term to minimize the risk of breaching the Cost Cap.

- *Recommended TI Policy Design:* TI-2a, which uses the current DO construct with a customized SACP to navigate the Kink years' budget constraint[7] and implementation of SREC Factors, is our recommended choice for the TI. Of all the potential modifications to the policy paths under consideration relative to the "status quo" options, adding SREC Factors provides the most substantial increase in both Cost Cap headroom and reduction in ratepayer NPV of ratepayer cost. Table 21 in the main body of the report presents the results of the TI-2a sensitivities. Within option TI-2a, the choice of incentive term (e.g., 10, 15 or 20 years) is a trade-off between the probability of breaching the Kink year budget cap (which militates for a longer term) and NPV of rates (which militates for a shorter term). This decision may be better informed by further analysis of the price of SRECs during the Kink period (EY 2022-24). However, currently the Consulting Team recommends a conservative approach, with the adoption of a 20-year term to minimize the risk of breaching the Cost Cap.
- *Comparing TI-2a and TI-2b:* Table 22 in the main body of the report displays a comparison of the implementation issues for policy cases TI-2a and TI-2b. While the "perpetually short" option with SREC Factors (TI-2b) offers lower overall ratepayer costs, it provides limited additional headroom relative to the more straightforward DO-style program with SREC Factors (TI-2a), despite having a much lower SACP during the Kink period. In addition, as mentioned above, success of TI-2b would require financiers to be confident that future Boards would not countermand the intent of the perpetual short structure, which may not be possible.
- *Other Policy Designs Likely to Reduce Ratepayer Costs and Risks of Cost Cap Breach:* TI-4 provides the greatest headroom under the Cost Cap and the lowest overall cost to ratepayers relative to the "status quo" options (TI-1a and TI-1b). Similarly, TI-3 creates materially greater Cost Cap headroom than a traditional DO-style approach, as well as lower overall ratepayer costs. Despite providing ratepayer and Cost Cap compliance benefits, however, our assessment is that implementing these approaches on a short time frame is likely to be challenging, and (in the case of TI-4) could limit the Board's options when developing a Successor Program (given the significant shift away from a DO-based framework required by the policy design and its impact on business structures).
- *Policy Options Similar to Preserving "Status Quo":* The Consulting Team does not recommend TI-1a and TI-1b, as either is projected to cost ratepayers hundreds of millions of dollars more on an NPV basis compared to similar policy options that include a differentiation of incentives using SREC Factors.

[7] See the Excel version of Attachment 2 for these ACP results.

1. Transition Incentive Option Development

1.1. Introduction

The analysis of the Transition Incentive (TI) requires a determination of what type(s) of incentives could reasonably be deployed. To develop a viable list of prospective incentives, the Consulting Team has incorporated three main elements:

1. A strong understanding of potential incentive types and design elements, as well as the technical feasibility of implementing each;
2. A set of guiding principles provided by the BPU Staff for the Solar Transition; and
3. Stakeholder feedback.

This section discusses these elements and the steps taken to generate TI options for analysis.

1.2. Transition Incentive Implementation Assumptions

This analysis is based on important assumptions about the implementation of the TI, including:

- The Clean Energy Act of 2018 (Clean Energy Act) set bounds of what can be considered for a policy response. For New Jersey solar photovoltaic (PV) installations interconnected to the in-state distribution system, the TI is intended to be a short-term bridge incentive program between the end of the current (legacy) SREC program and a still to-be-determined Successor Program incentive.
- The Solar Transition Principles provided in the Staff Straw Proposal issued December 26, 2018 (Staff Straw Proposal) and repeated in the Staff Stakeholder Notice issued April 8, 2019 (April Notice) provide, to the extent applicable, proposed governing principles on the adoption of and analysis of viable incentives choices. Parties recognize, however, the possibility of conflicting goals, as discussed below.
- The TI will be available to projects yet to reach commercial operation by the time the 5.1% attainment threshold is reached and allow projects that are qualified via the SRP but that do not qualify for the legacy SREC program to participate in the TI. Further, we assume that any project currently in the SRP that does not qualify for the legacy SREC program will automatically be registered for the TI by default.
- No project in the SRP pipeline could proceed without an incentive greater than the NJ Class I REC value and achieve an acceptable ROI. This assumption is informed by the results of the CREST model,[8] which shows that all project types require a PBI higher than the NJ Class I REC value for our base cost case.

[8] Cost of Renewable Energy Spreadsheet Tool (CREST) is a model developed by Sustainable Energy Advantage, LLC for National Renewables Energy Lab. For more information see https://www.nrel.gov/analysis/crest.html.

- The Successor Program will begin when the transition point has been deemed to have occurred—i.e., when it is deemed 5.1% of the New Jersey retail load has been met by solar generation.
  - The TI will only be available to projects that are qualified via the SRP but that do not qualify for the legacy SREC program prior to the commencement of the Successor Program (SP).
    - Note, this is an important assumption, and if relaxed may have material design implications (e.g., more projects qualify for the TI and thus all things being equal the TI is more expensive to ratepayers). We will discuss below implications if this assumption is incorrect or relaxed (e.g., the SP does not commence upon attainment of the 5.1% milestone, and therefore the TI registration period is extended until the SP commences; a possibility mentioned in the April Notice).
  - While the methodology for calculating attainment of the 5.1% milestone is yet to be finalized, our assumptions currently lead us to estimate that the 5.1% milestone will be reached around September 2020. To estimate the attainment of the 5.1% milestone, we divide the trailing 12-month average of solar generation (calculated by multiplying the cumulative installed solar capacity for the previous twelve months by a corresponding solar output factor for each month assuming 1200 MWh/MW_{DC} in annual production) by the load obligated under the most recent RPS compliance report (73,679,057 MWh).
- The TI project mix of larger projects (> 25 kW_{DC}) is constrained by those projects presently in the SRP pipeline.[9] It is assumed that most smaller projects (< 25 kW_{DC}) have much shorter lead times. As a result, there will be a smaller queue of small projects in the pipeline at the time of 5.1% attainment and thus a smaller portion will qualify for the TI. Although small projects continue to join the SRP pipeline at a rate comparable to their installation rate, we assume that projects joining the SRP pipeline after 5.1% is attained will qualify for the successor program. We assume that all projects currently in the pipeline that qualify for a 15-year QL will be built before the 5.1% milestone is attained.

[9] The capacity and project mix in the pipeline at the time of 5.1% attainment is a function of the assumed build rate and the assumed application rate prior to the 5.1% attainment. See Attachment 1 for details.

1.3. Range of Transition Incentive Options Considered

The analysis of TI options begins with a broad list of potential solar incentives utilized in other markets and is pared down to the set of choices most applicable to New Jersey. Figure 1 below displays a summary of the broad categories of solar incentives potentially applicable to the TI. The general categories are contained in the left-hand column, and more specific incentives available within each broad category are provided in the second column. The general categories potentially applicable to the TI are defined as follows:

- **Direct Up-Front Incentive** is an upfront cash payment, typically in the form of a grant or rebate, to defray capital costs (which can be provided either upon qualification, commercial operation, or a time in between).
- **Direct Long-Term (LT) Revenue Hedge** provides a long-term, "bankable", fixed-price "hedge" to one or more revenue streams, typically through a power purchase or financial transaction under either a contract or tariff vehicle. In practice this means a known price schedule per kWh (or less commonly kW) for each kWh produced by the project. This hedge leads to overall lower financing costs than either a project receiving variable revenue per unit production (e.g., revenue based on variable locational marginal price) or a Demand Obligation without a hedge (as described below), because revenue risk has been diminished compared with unhedged revenue. Revenue hedges can range from full to partial (the latter hedging, for example, only the energy or attribute revenue streams).
- **Demand-Pull / Demand Obligation (DO)** provides a market-based incentive where the TREC price is a function of supply, demand, alternative compliance payment (ACP) rate and other features, such as banking. Under a DO, the incentive price is variable and thus deemed unhedged. For TI purposes, the incentive only covers the "environmental" attributes, whereas the energy / capacity is valued via different means. All else equal, this unhedged incentive results in a riskier revenue stream and thus higher financing costs than incentive structures that provide a hedge to one or more revenue streams.
- **Hybrid DO / Long-Term Hedge** is a DO with a price floor that provides a hedge to downside risk. All else equal, this provides more revenue certainty than a DO without a revenue hedge, and thus project development financing costs are lower for the Hybrid DO / Long-Term Hedge incentive category than the Demand-Pull / DO category.

Exogenous incentives or co-incentives that will be factored into the analysis of a SP but are not considered for the TI include:

- Expenditure-Based Tax Incentives (such as the federal Investment Tax Credit (ITC) and MACRS/bonus depreciation allowances); and

- Net Metering (NM)[10]

In subsection 1.4, we discuss the considerations for excluding certain incentive categories and subcategories from consideration for the TI analysis. While some incentive options may not be appropriate for the TI (e.g., since certain options are extremely difficult to implement with broad stakeholder consensus in a timely manner), they may be considered viable as an option for the SP.

Figure 1 – Categorization of Incentives Applicable to TI

Category	Subcategory / Examples	Applicable to "NJ Solar Transition"	Reference Incentives in Other Markets and Additional Comments
Direct Upfront Incentive	Grants / Rebates	X	Pre MA SREC I Grants (Very high cost incentive structure)
Direct Long-Term (LT) Revenue Hedge	Feed-in Tariff / Standard Offer / PBI Contracts or Tariff	✓	MA SMART, RI REG
	Competitive Long-term PPA	✓	CT ZREC, NY Wind
	LT Value of Solar	?	Difficult to implement in a short period of time. Most successful example is NY VDER, a continual work in progress
	Technology-Specific "Avoided Costs"	X	e.g., FERC long-term avoided cost rates.
Demand-Pull / Demand Obligation (DO) w/o Revenue Hedge	RPS / SREC Markets	✓	NJ SREC, MD SREC
Hybrid DO / Long-Term Hedge	SREC w/ Floor	✓	MA SREC I & II (both policies have "soft" floor that represents a form of partial hedge)
Indirect Financial Incentives	Emission Markets	N/A	Exogenous; accounted for in energy prices specific to NJ zones
Expenditure-Based Tax Incentives	Tax Credit	N/A	Exogenous; accounted for in calculation of non-PBI incentive revenue per project
Net Metering (NM)	NM crediting mechanism, Virtual NM (VNM) Crediting Mechanism, Community Solar	N/A	Co-incentive; accounted for in calculation of non-PBI incentive revenue per project

[10] Currently, SEA's Cost of Renewable Energy Spreadsheet Tool (CREST) model is set up to calculate the incentive gap (in net present value terms) between the project's total revenue requirement ($/MWh) and the amount of "market" and incentive revenue it receives. Both the federal incentives (ITC/depreciation) and net metering are accounted for in this analysis as forms of revenue that most solar projects in the TI are expected to receive (to varying degrees).

1.4. High Level Screening of Transition Incentive Options

In this section, we review the proposed screening that was presented to stakeholders in Stakeholder Workshop 2 (June 14, 2019, Newark), and received no negative feedback.

We begin with the policy options the Consulting Team proposed to be non-viable for the TI, before turning to the options considered cost-effective and possible to implement prior to the attainment of 5.1% (assumed to be in September 2020).

1.4.1. Non-Viable Options for Transition Incentive

Referring to Figure 1 above, the Consulting Team proposed (to general approval) ruling out the following incentive categories for TI consideration.

- **Direct Upfront Incentive**: This requires an entity to pay for the incentive and (for a program the scale of the TI) a very large budget to fund the incentive program. The ability to identify and work with an entity to set up and be ready to provide up-front incentives would require time. Such approaches are typically deployed using system benefits charge (SBC) funds for programs and incentives of more modest scale, and New Jersey has long ago moved beyond this structure. New Jersey itself opted in 2006-7 to transition away from solar rebates—a direct, upfront incentive programs—to SRECs as the primary incentive, in large part due to the constraints with the rebate budget and process, as well as the maturity of the market.
- **Competitive Procurements (e.g. Requests for Proposals, Auctions or Tenders):** Options based on EDC- or third party-run competitive procurement for offtake contracts (TRECs only or in addition to energy and/or capacity) would generally require the establishment of a competitive procurement process to set the price for the large-project segment, while the small-project segment would typically receive an administratively-determined incentive or a derivative one (e.g., small projects get a set percentage of the incentive value provided to larger projects). While such processes, with appropriate bidding safeguards to avoid a “race-to-the-bottom” effect, can incent development at a substantially lower cost to ratepayers, the time required to implement a competitive process – design, approve, solicit, allow for development of responses (bids), and evaluate – is likely much longer than the time available before the start of the TI. Furthermore, it is intended that the TI is a closed market in which projects are not competing for available capacity, and a competitive procurement is contradictory to that intent.
- **Long-Term Value of Solar Tariff:** Analyzing, setting up and implementing a value-of-solar (VOS) incentive structure is very complex and difficult to implement. There is little experience in the industry with fully and successfully implementing such an approach in a competitive electric market. The most prominent example is the New York Value of Distributed Energy Resources (VDER), which has been years in the making and is a continual work in progress. Implementing a credible VOS incentive for the TI, therefore, does not appear viable in the available time.
- **Direct Long-Term (LT) Revenue Hedge – Technology Specific “Avoided Costs”:** Qualifying Facility (QF) tariffs under the Public Utility Regulatory Policies Act of 1978 (PURPA) are an

example of value-based tariffs that may provide long-term fixed prices for specific technologies (e.g., hydro, wind, solar). In the context of the TI (and ultimate successor), the issue with this type of tariff is that it is an open-season program which does not restrict the number of MW that may qualify as a QF prior to the start of the SP. As a result, there technically would not be a cap on the total incentives paid out, and thus such an approach cannot guarantee that it will not violate the cap.

- **Demand Obligation (DO) with a soft floor via a clearinghouse auction and a supply-responsive demand formula**: While a market supply-responsive demand formula (such as the Solar Carve Out and Solar Carve Out II (SREC I and II) used in Massachusetts) can offer benefits, it suffers from several drawbacks: (1) designs utilizing a soft floor also rely on future adjustments to demand to stimulate purchases of surplus SRECs, which makes little sense for a program with a relatively small and defined pool of potential capacity and a short duration for entry, (2) it is unfamiliar to many in the New Jersey market, and (3) would be complicated to implement.
- **DO with an open firm floor price mechanism via a buyer of last resort**. There are at least two variants to this approach.
  - **Upfront Variant:** An upfront variant would allow the project or the holder of the TRECs to have a put option to sell the TRECs to the buyer of last resort at a known fixed price as they are produced, but must exercise the put option once for all of its TRECs over the incentive term either during project development or soon thereafter. For example, the put option for the upfront variant is available for a set duration window of 120 days after a project reaches commercial operation.
  - **Backend Variant:** A backend variant would, when a TREC remains unsold at end of its qualification life (e.g., after 3, 4 or 5 years), provide the holder of the yet-to-be-retired TRECs with an option to sell the TRECs for a known price to the buyer of last resort.

  Identifying and putting in place either variant of a buyer-of-last-resort mechanism will be difficult for the expected TI timeframe; the upfront variant would be particularly difficult to implement because of time constraints, while a backend variant may be less difficult, particularly if some of program details need not all be figured out by the start of the TI. In addition, it is likely that only a program that follows a well-worn path (such as a reboot of the Three EDC SREC Purchase Program) would have a decent chance of coming to fruition in the short-time frame.[11]
- **Exogenous Incentives/Co-Incentives:** As discussed above, the last three categories of incentives in Figure 1 – Indirect Financial Incentives, Expenditure-Based Tax Incentives and Net Metering — are not within the set of incentives directly considered as possible TI. They will be considered in

[11] See the latest program's website: https://njsolarprogram.com/2018/06/06/nj-solar-program-insights/. Of note, the last iteration of the purchase program was officially named the "NJ Solar SREC-II program." To avoid confusion, we are identifying the purchase program within this report as the "Three EDC SREC Purchase Program."

the context of calculating the Cost Cap (as well as the total value of the gap between project revenue requirements and total expected revenue in the absence of incentives).

1.4.2. Potentially Viable Options for Transition Incentive

Demand Obligation and certain direct, long-term hedge approaches may be viable for implementation for the TI.

- **Direct Long-Term Revenue Hedges via PBIs (specifically, Administratively-Set Incentives)**: An administratively-set incentive (which would pay for either (i) the premium over wholesale, or (ii) energy and RECs, or (iii) energy, capacity and RECs) would likely be a good fit for the TI, which is a time-bounded incentive for a specific set of projects still in the Legacy SREC pipeline when 5.1% is attained. While the key feature of a Declining Block Incentive (DBI) or Adjustable Block Incentive (ABI) is that over time the level of incentive is adjusted, the short duration of the TI (and the specific set of projects it applies to) obviates the need to change the incentive, and thus obviates the need for a DBI or ABI.
- **Demand Obligation (DO)-Based Options:** An unhedged DO, or a DO with a partial long-term hedge, would require only incremental adaptation from the Legacy SREC program structure, making implementation feasible. The specific types of DO-based structures potentially viable for the TI include:
  - **Separate RPS tier for solar**. For example, a TREC incentive where TRECs have their own compliance obligation and are priced and traded separately from legacy SRECs.
  - **Separate RPS tier for solar (e.g., MA SREC II) with "TREC Factors"**. The market structure mirrors some features of the Solar Carve-Out II (SREC II) program in Massachusetts, in which incentives are differentiated to reflect different levelized costs for different project types and/or to implement various policy goals (such as encouraging preferred installation types or discouraging less preferable installation types of locations). TREC Factors are constants set at levels less than or equal to one and would be multiplied by the MWh production of a specific solar installation to determine the number of TRECs granted per MWh (thus, each MWh produced would correspond to some fraction of one TREC). For example, New Jersey may want to incent brownfield solar and solar carport development (using already developed/disturbed land) but disincentivize greenfield, ground-mounted solar development. In this case an TREC Factor of 1.0 might be given to brownfield and solar carport projects, while an TREC Factor of 0.7 might be given to greenfield projects.
  - **Separate RPS tier for solar (with or without TREC Factors) with a limited, firm-floor price mechanism**. This approach requires a buyer of TRECs at a fixed price over a fixed term. One implementation example is that sellers would have a one-time opportunity (e.g., 90 days after receiving its SRP) to exercise this put option and thus it would create a firm-floor price for financing purposes. Conversely, there would be no firm-floor price for project developers that did not exercise this upfront put option. The benefit of this approach is that offering a price hedge would allow for lower cost financing, and thus some project owners may be willing to develop and sell at a lower expected cost than their expected revenue in an

unhedged market.[12] The buyer would presumably resell these TRECs into the market with any net difference (less the transaction costs) from the purchase price passed through as a non-bypassable wires charge. This, in practice, means that the ratepayer effectively experiences a reduced purchase price from the fixed price hedge paid by the EDCs.[13] New Jersey has precedent with such a program with the recently closed Three EDC SREC Purchase Program. This program awarded 10-year, fixed-price SREC contracts through a competitive process in three utility service territories. This was an example of an SREC program with a limited scale, firm-floor price mechanism. Even though it requires an offtaker (the EDCs in this case), we do not reject this incentive structure out-of-hand: NJ market participants are familiar with the construct, and such a structure could potentially be "dusted off" and leveraged for re-use with relatively minor modifications. Nonetheless, the approval process could be time consuming obviating the potential for this policy structure to be used for the TI.

Table 1 provides a summary of the applicability of alternative (non-demand obligation based) structures or approaches for implementing direct long-term revenue hedges via performance-based incentives (PBIs). It does so for the TI and SP and considers generically the suitability for application for both 'small' and 'large' projects, where a "✓" means the alternative is suitable for further consideration while an "X" is deemed unsuitable.[14] There are many more incentive policy options available for the SP, because it is not bound by the TI's time- and pipeline- implementation constraints. In addition, Table 2 provides a summary of incentive structures based on demand obligations (conventional or hybrid). A continuation of the SREC legacy market is ruled out, as it is our understanding that the Energy Act explicitly precludes extending the SREC legacy market. Conversely, it is our understanding that the Clean Energy Act gives the BPU broad authority to implement a wide variety of successor incentives, which could include a 'TREC' market separate from the legacy SREC market.

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[12] As modeled in this analysis, this option entails a one-time buyout – however, it is possible for a buyout to be available on a rolling basis, but if more buyouts were taken later in the term of the incentive, the cost to ratepayers would grow closer to the cost of TI-2a.

[13] Such a program would have to decide under what circumstances that the EDCs would sell TRECs back into the market. In the simplest approach it would be automatically (e.g., conduct a sale auction every quarter) regardless of TREC price. If the TREC market prices were above the floor price, then ratepayers would receive an overall bill credit when netting against the firm-floor price over by the EDCs. Conversely, if the TREC market prices were below the floor price, then ratepayers would receive an overall bill debit when netting against the firm-floor price over by the EDCs.

[14] In this instance, the Consulting Team does not specifically define small and large. Experience in both New Jersey and other jurisdictions suggests that the line between small and large can be drawn in a variety of ways, but in general, 'small' systems will include, at a minimum, mass market installs of ≤ 25 kW_{DC}, while 'large' systems will at a minimum include utility-scale grid-connected projects typically exceeding 1 MW_{DC}.

Table 1 – Non-Demand Obligation Options: Direct Long-Term Revenue Hedges/PBIs

Alternative Structures ("Open" to all projects or "Closed" via a selection process)	TI Small	TI Large	SP Small	SP Large
Cost-Based Performance Based Incentive (PBI) Tariff: Declining Block Incentive (DBI) (Open)	X	X	✓	✓
Cost-Based PBI Tariff: Adjustable Block Incentive (ABI) (Open)	X	X	✓	✓
Cost-Based PBI Tariff: Administratively established price; periodic reset (Open)	✓	✓	✓	✓
Request for Proposal/Auction/Tender Competitive Long-Term Power Purchase Agreement (Closed)	X	✓	X	✓
LT Value of Solar Tariff (Open)	X	X	✓	✓ Except utility-scale/grid-connected

Table 2 – Demand Obligation Options (Conventional Unhedged or Hybrid)

Alternative Structures	TI Small	TI Large	SP Small	SP Large
SREC within existing tier (i.e., legacy market continuation) with SREC Factors	X	X	X	X
Separate RPS tier for solar (e.g., TREC)	✓	✓	✓	✓
Separate RPS tier for solar (e.g., TREC) with TREC factors	✓	✓	✓	✓
TREC with Soft Floor via a clearinghouse auction and a supply-responsive demand formula (e.g., like MA SREC I and MA SREC II)	X	X	✓	✓
TREC with an open firm floor price mechanism via a buyer of last resort	?	?	✓	✓
TREC with a limited firm floor price mechanism (e.g., quantity-limited RFP/buyer of last resort)	✓	✓	✓	✓

1.5. Transition Incentive Design Criteria and Binding Constraints

In crafting potential TI options, sections 1.3 and 1.4 broadly considered what TI options are technically possible to implement. In this section 1.5, we lay out design criteria, guided by BPU Design Principles and stakeholder input gathered at Stakeholder Workshop #1, that can be applied to further evaluate and prioritize options. In the following section (1.6), we apply these design criteria to determine recommended approaches.

1.5.1. SREC Transition Principles

In the Straw Proposal and April Notice, BPU Staff laid out the following **Solar Transition Principles** that would inform the Solar Transition process and design.

1. *Provide maximum benefit to ratepayers at the lowest cost;*
2. *Support the continued growth of the solar industry;*
3. *Ensure that prior investments retain value;*
4. *Meet the Governor's commitment of 50% Class I Renewable Energy Certificates ("RECs") by 2030 and 100% clean energy by 2050;*
5. *Provide insight and information to stakeholders through a transparent process for developing the Solar Transition and Successor Program;*
6. *Comply fully with the statute, including the implications of the cost cap; and*
7. *Provide disclosure and notification to developers that certain projects may not be guaranteed participation in the current SREC program and continue updates on market conditions via the New Jersey Clean Energy Program ("NJCEP") SREC Registration Program ("SRP") Solar Activity Reports.*

Table 3 converts the Solar Transition Principles into six, separate directives that are relevant to the modeling of the prospective TI policy options in this analysis. The list excludes Principles that are only relevant to the legacy program and the Transition process.

Table 3 – Solar Transition Principles Relevant to TI Policy Option Development

Solar Transition Principles for TI
a. Maximize ratepayer benefit
b. Minimize ratepayer cost
c. Support solar industry growth
d. Ensure prior investments retain value
e. Meet 50% Class I RECs by 2030
f. Binding Constraint: Comply with Rate Cap

1.5.2. Stakeholder Workshop #1 Feedback

On May 2, 2019, BPU hosted and the Consulting Team led the first of three consultant-led Stakeholder Engagement Workshops planned as part of the New Jersey Solar Transition. During Stakeholder Workshop #1 (SWS1), the Consulting Team presented material and elicited stakeholder feedback regarding their preferences for policy option objectives for both the TI and SP.

Table 4 provides a summary of design criteria created by the Consulting Team based on preferences elicited during SWS1. The Consulting Team worked with participating stakeholders in "breakout groups" to determine their priorities for policy design objectives, denoted as checkmarks in Table 4 below. Stakeholders voted their preference for objectives to be considered more important or "primary" for the TI and the SP. Table 5 provides a summary of "secondary" criteria for the Transition and the Successor Program—i.e., policy design objectives that were deemed relevant, but less important than the primary list.

It is important to note that this summary reflects only the opinions of those stakeholders present at the workshop, a majority of which were from the solar industry. Care should therefore be taken in drawing conclusions from the results presented in Table 4 and Table 5 below. Additional stakeholder engagement may be required to obtain a more complete picture of the positions and recommendations of other relevant stakeholders not present at SWS1.

Table 4 – Summary of Stakeholder Elicited Primary Design Objectives for TI & SP

Primary Design Criteria from SWS#1	TI	SP
1. Fair to those who have made past commitments	✓	✓
2. Fair to those who will make future commitments	✓	✓
3. Clarity and transparency regarding project eligibility and status	✓	✓
4. Implements a fair and transparent process for scrubbing non-performing project from qualification queuing procedures	✓	✓
5. Minimizes market disruption (minimize high transition costs)	✓	✓
6. Supports steady industry growth	✓	✓
7. Maximizes certainty of incentive access	✓	✓
8. Minimizes complexity	✓	✓
9. Maximizes solar PV installation growth	✓	✓
10. Feasibility	✓	✓

Table 5 – Summary of Stakeholder Elicited Secondary Design Objectives for TI & SP

Secondary Design Criteria from SWS#1	TI	SP
11. Maximizes cost-effectiveness (most MW per ratepayer dollar)	✓	✓
12. Minimizes ratepayer impact	✓	✓
13. Maximizes ratepayer net benefit (including environmental considerations)	✓	✓
14. Reduces incentive levels over time		✓
15. Maximizes solar development on disturbed land/minimizes reliance on green space		✓
16. Encourages installation type diversity		✓
17. Minimizes financing risk	✓	✓
18. Encourages participant diversity		✓
19. Maximizes near-term jobs in NJ		✓
20. Maximizes long-term jobs in NJ		✓
21. Maximizes use of competitive market mechanisms		✓
22. Maximizes compatibility with competitive wholesale energy markets		✓
23. Maximizes compatibility with competitive retail energy markets		✓
24. Allows timely implementation	✓	
25. Supports PV location where most needed		✓

1.6. Secondary Screening Accounting for Design Criteria and Stakeholder Input

On June 14, 2019, the Consulting Team led the second Stakeholder Engagement Workshop (SWS2) planned as part of the Solar Transition. During the June 14 Stakeholder Workshop, the Consulting Team presented seven archetypal policy paths for stakeholder feedback during a breakout session. These policy paths are summarized in Table 6. From left to right, the policy paths presented range from most similar to the current SREC program, to least similar to the current SREC program. The current SREC program is considered a “Demand Obligation” incentive type (as are TI-1, TI-2, and TI-3), while TI-4 through TI-7 are Long-Term Hedge incentive types.

As noted above in Section 1.3, Figure 1 displays the initial feasibility screening criteria presented and discussed with stakeholders. Stakeholders were also reminded of the BPU Solar Transition Principles and the results of stakeholder feedback on design objectives from SWS1 (see Sections 1.5.1 and 1.5.2).

During a breakout session, the workshop split into four groups, each led by members of the Consulting Team and BPU staff. Each breakout group critiqued the specifics of the policy path attributes. Stakeholder participants ultimately “voted” for a first, second, and third choice policy as well as optionally indicating a policy which they strongly opposed, along with the reasons for their objection (“remove”). To have apples-to-apples comparisons and to not render the voting ineffective, the Consulting Team chose discrete options, and did not allow for changes and emphasized that the options were selected as illustrative paths within the range of a vast multitude of paths that could be selected. Thus, there was nothing definitive about the specific attributes of the presented policy paths and that based on preferences and various criteria, other modified options could also be considered. Feedback on individual attributes were elicited during the breakout session.

The top-level results of the breakout groups’ policy pathway rankings are as follows.

- TI-2 and TI-3 were most popular
- TI-5 and TI-7 were least popular
- While TI-2 was the highest ranked, there were also many stakeholders who did not want this policy pathway
- TI-7 across all groups received most knock out (i.e., remove) votes
- TI-6 some stakeholder liked but some stakeholders really hated.

Table 6 – TI Policy Path Options Presented for Feedback During SWS2

<table>
<tr><th>Transition Incentive Policy Path →

Attribute ↓</th><th>TI-1. Minimize disruption: Same game, different ballpark</th><th>TI-2. Minimize disruption with differentiation: Factorized SRECs</th><th>TI-3. Minimize disruption with differentiation and price stability: Factorized SRECs w/ buyback</th><th>TI-4. Achieve project diversity goals: PBIs allocated by market segment</th><th>TI-5. Achieve project diversity goals: PBIs for all with MW allocations by segment</th><th>TI-6. Even Lower Financing Costs: Competition for larger, admin.-set PBI for smaller</th><th>TI-7. EDC Custom: Competition for large, admin-set PBI for small; incentive differentiation by EDC</th></tr>
<tr><td>Incentive Type</td><td colspan="3">Demand Obligation</td><td colspan="4">Long-term Hedge</td></tr>
<tr><td>Analog</td><td>NJ SREC</td><td>NJ Solar/
MA SREC II Combo</td><td>NJ SREC w/ PSEG Loan, MA SREC II</td><td>RI DG Standard Offer</td><td>RI DG Standard Offer</td><td>RI RE Growth; SMART (w/o DBI)</td><td>CT ZREC</td></tr>
<tr><td>Counterparty</td><td colspan="3">LSEs buy RECs</td><td colspan="4">EDCs</td></tr>
<tr><td>Price-setting and adjustments</td><td colspan="2">Market-based</td><td>Market-based. Buyback mechanism creates firm price floor for a subset of SRECs</td><td colspan="2">Administratively-established standard offer, cost-based; not adjusted</td><td colspan="2">Competitive auction for large(st) projects; Cost-based, administratively-established for smaller projects</td></tr>
<tr><td>Incentive Access; Queueing</td><td colspan="3">Open, SRP application acceptance = qualification</td><td colspan="2">Open, SRP application acceptance secures queue position</td><td colspan="2">Auction for large(st) projects; SRP application acceptance secures queue position for smaller projects</td></tr>
<tr><td>Attributes purchased, hedged</td><td colspan="2">SRECs purchased, no hedge</td><td>SRECs purchased. Implicit price floor w/ buyback mechanism for limited quantity of SRECs</td><td colspan="2">Premium incentive: Fixed price paid for attribute. (Incentive hedged; Energy & capacity unhedged)</td><td>Fixed price for energy and incentive</td><td>Premium incentive: Fixed price paid for attribute. (Incentive hedged; Energy & capacity unhedged)</td></tr>
<tr><td>Installation Diversity/ favoring mechanism</td><td>None</td><td colspan="2">Vary SREC Factors by type/size based on cost gap or policy preference</td><td>Vary PBI level by segment based on cost gap & policy preferences, Min.set-aside for < 25 kW segment</td><td>Vary PBI by segment based on cost gap & policy preferences. MW goal set for each distinct market segment</td><td>Small: Vary PBI by type/size based on cost gap and policy preferences, Large: MW sought in RFP</td><td>Small: Vary PBI by type/size based on cost gap & policy preferences, Large: MW sought in RFP & by EDC</td></tr>
<tr><td>EDC Diversity</td><td colspan="3">N/A</td><td colspan="3">No inter-EDC allocation constraints</td><td>Allocate quota by EDC</td></tr>
<tr><td>Net Metering Interaction</td><td colspan="4">Separate from Net Metering</td><td>Separate from net metering, but size of NMC factored into incentive size</td><td>Fixed total compensation → Higher NMC results in lower incentive payment</td><td>Separate from net metering, but for admin.-set incentive, size of NMC factored into incentive size</td></tr>
<tr><td>Predictability of Annual Market Scale</td><td colspan="3">Target defined by % of load targets in aggregate (not by market segment) (however, no constraint on market response)</td><td>Separate “program” MW caps for (i) ≤25kW, (ii) all others</td><td>Firm Target</td><td colspan="2">MW Cap,; Solicitations have a target quantity of MW</td></tr>
<tr><td>Other Features</td><td colspan="3">Duration: 10 years of SRECs, Class I RECs thereafter</td><td colspan="2">Duration: 20 year tariff; EDC resells products purchased into markets; COD sunset per SRP/EDC interconnection</td><td colspan="2">Duration: 20 year tariff</td></tr>
</table>

1.7. Resulting Transition Incentive Options

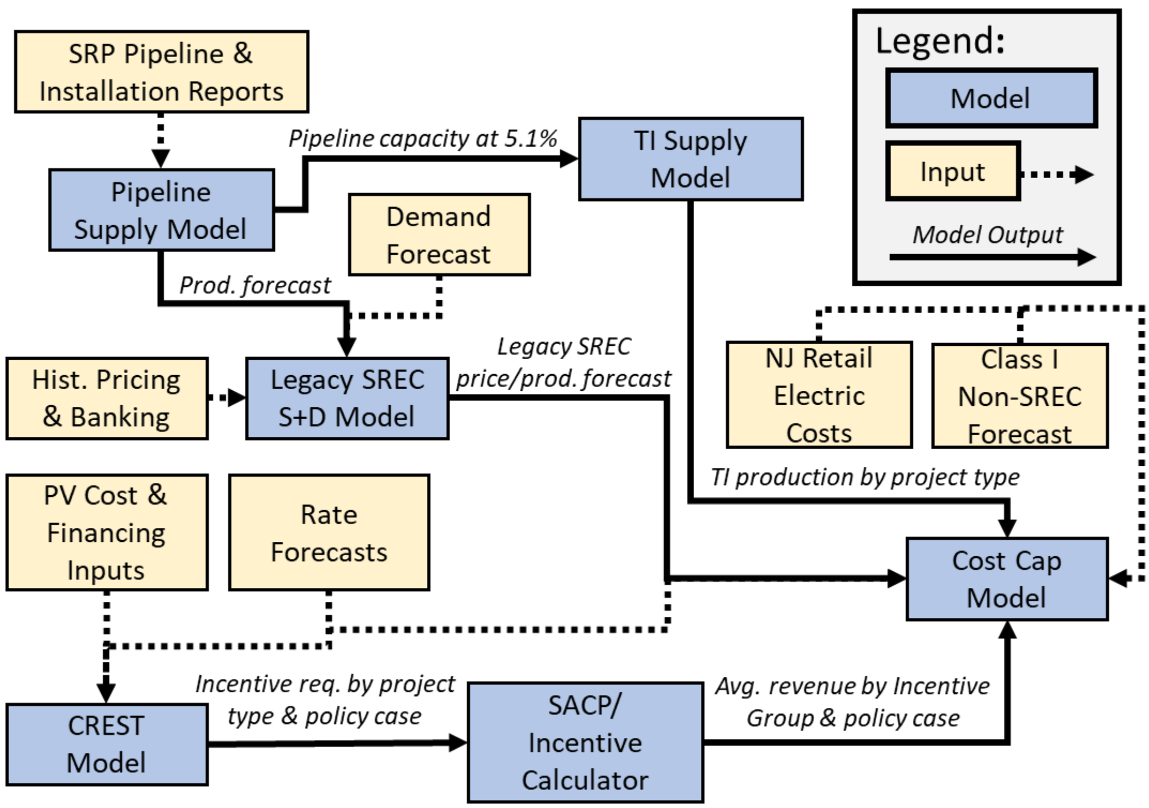
Given time and budget constraints, and per the Solar Transition Principles, stakeholder feedback and in consultation with BPU, it was decided to winnow down the analysis set to variants of TI-1, TI-2, TI-3 and one of TI-4 or TI-6. It was decided to model a variant of TI-4 rather than TI-6 because TI-6 included a competitive auction as a key component, and because TI-6 had a far larger number of significant detractors that wished to see it removed as an option, along with few strong supporters (see Appendix A for more detail).

2. Analysis & Modeling of Selected Transition Incentive Options

2.1. Methodology & Key Assumptions

Our modeling of each TI policy case relies on a variety of inputs and models that interact to produce the results presented in this Report. A graphical depiction of each model's inputs and outputs is provided below (see Figure 2), followed by an overview of methodology and key assumptions behind each step of the modeling process. For details on the specific inputs and outputs used, see the separate Attachment 1.

Figure 2 – Modeling Overview



Forecasting Legacy SREC Production and 5.1% Attainment: To forecast legacy SREC production we utilize a pipeline supply model that models the monthly SREC production from projects currently installed and in the pipeline. To forecast the production of projects currently installed, the model calculates the historic incremental capacity installed per month from 2004 to present based on each project's permission to operate (PTO) date supplied in the SREC Registration Program's (SRP's) May 2019 installation report (issued June 19, 2019). The monthly production from each cohort of monthly installations is then forecasted through 2033 (differentiating between projects with a 10 or 15-year QL). To estimate production, the model assigns each project a capacity factor based on its size and customer type (see Attachment 1). Monthly capacity factors are scaled by a monthly index to reflect seasonal variation in production and are subject to a 0.5% annual degradation rate. Projects that have been operational for years but have not been deemed "complete" in the SRP report or projects that are passed their Qualification Life (QL) are not included in production estimates.[15] Production estimates are compared to production actuals from PJM GATS to ensure the model's accuracy when back-casting.

To forecast the production of projects in the pipeline, the model assumes monthly installations will follow historic averages per project size category, subject to the constraints of the capacity available in the pipeline.[16] The total capacity available in the pipeline is de-rated to reflect the likelihood that projects will drop out (the "scrub rate", assumed to be 30%), to remove projects that have passed their expiration date, and to discount projects that have taken longer than usual to reach PTO. The scrub rate and average time to reach PTO are informed by a separate cohort analysis which assessed the development outcomes of projects in the November 2016 Pipeline Report.[17]

To calculate the month in which total solar sales represent 5.1% of retail sales, the model multiplies the cumulative installed capacity in each month by a monthly production factors that result in 1200 MWh/MW of production on an annual basis. The trailing 12 months of solar production is then divided by the obligated load from the most recent RPS compliance report (73,679,057 MWh).

Forecasting Legacy SREC Prices: To forecast legacy SREC prices through 2033, we utilize a supply demand model that calculates the supply demand dynamics (including banking and SACP payments) in each energy year based on the pipeline supply model's yearly SREC production estimates and a demand forecast (see Attachment 1). The model estimates each year's price based on the year's bank balance as a percent of the compliance obligation. The pricing equation's coefficients are informed by a separate regression analysis which assesses the relationship between historic prices and bank balances as a percent of the year's compliance obligation. Base, high, and low pricing scenarios are generated by varying demand, supply, and the intercept of the pricing equation (for details, see Attachment 1). We assume that LSEs will retire all banked SRECs prior to retaining newly minted SRECs and that each year 0.5% of newly minted SRECs will never be retired based on historic PJM GATS data. Figure 3 below shows our pricing forecast by scenario.

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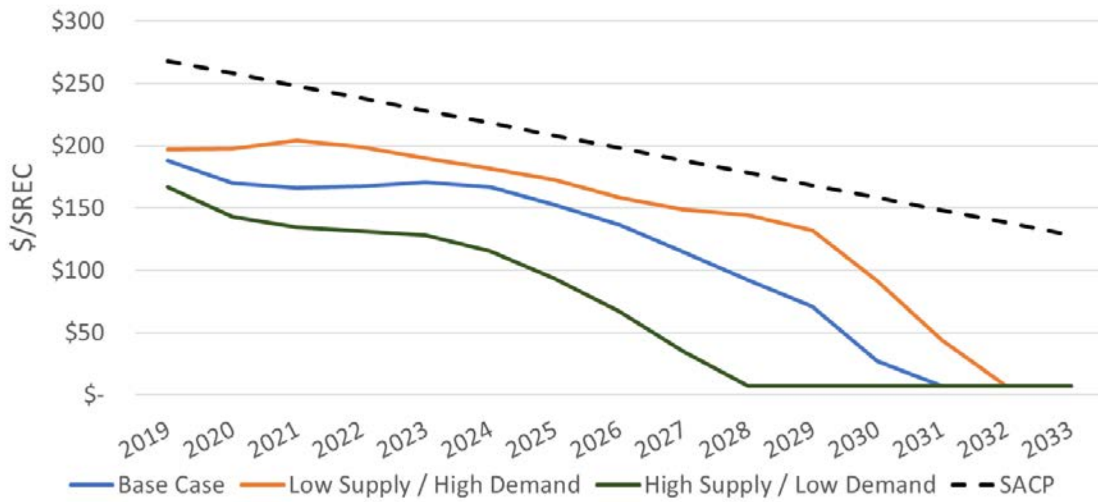
[15] After consulting with TRC, we believe many of these older projects that have not been deemed "complete" are generally associated Third Parties that are now out of business. See Attachment 1 for specific criteria.

[16] Available pipeline capacity only constrains the < 25 kW_{DC} size category in practice, as sufficient pipeline capacity exists for all other size bins to supply the average monthly build rate through the attainment of 5.1%. The capacity available in the pipeline is determined by taking the de-rated capacity from the SRP's May 2019 Pipeline Report and netting out assumed installations and applications for each month (see Attachment 1 for details).

[17] Although projects frequently fail to complete construction under their original term and must re-register to complete construction in a new term, this dynamic is captured by our use of historic application rates to estimate the pipeline's rate of replenishment.

Figure 3 – Legacy SREC Price Forecast by Scenario



Forecasting TI Capacity and Production: To forecast the capacity of the TI, we assume monthly installations will follow historic averages per project size category and EDC, subject to the constraints of the pipeline at the time of 5.1% attainment. We assume market shares for specific project types within each size category based on conversations with developers and the financial outlook of each project type provided by the CREST model (for details on the market shares assumed, see Attachment 1). To calculate the capacity of the pipeline at the time of 5.1% attainment, the pipeline supply model nets each month's incremental capacity installed with historic pipeline application rates (see Attachment 1), per project size category, up until the month in which 5.1% is attained. Historic application rates are informed by the last six months of applications contained in the May SRP Pipeline Report and are de-rated to account for projects that will apply but never become operational. Pipeline application rates are suppressed leading up to the release of the TI program rules in October 2019 to reflect developer uncertainty. Installations under the TI are assumed to begin the month after 5.1% is attained and progress through the end of 2023 (given that ITC safe harbor period ends January 1, 2024), subject to the constraints of the capacity available in the pipeline at 5.1% attainment. As a result, the timing of the 5.1% attainment influences the TI capacity in that it determines both the capacity in the pipeline that qualifies for the TI and the amount of time in which installations may occur before the 2024 cutoff. This results in 483 MW being installed under the TI. For the purposes of calculating production that will generate incentives under the TI, we assume that the incentive term will include a "stub year" (i.e., if a project comes online in Q2 2020, their remaining incentive term will not begin to decrease until the start of 2021).

Assessing Minimum Incentive Requirements by Project Type and Policy Case: To assess the minimum incentives required for market entry (the "cost of entry" or COE), per project type and EDC, we utilize the CREST model. The CREST model takes each project type's capital and operating costs, compounded by risk-adjusted financing costs and taxes, less the project's expected revenue and tax incentives, divided by the PV performance over its useful life, to arrive at the production-based incentives necessary for such a project to be economical to develop. We inform our inputs based on market surveys, cost data provided by EDCs and the BPU, and prior market knowledge. We assume that the design of each policy case impacts financial assumptions in that different policy designs are associated with different levels of revenue risk. In addition, we assume that all projects under 5 MW are net metered (except for the Small Landfill/Brownfield project type, for specific rate classes assumed per project type, see Attachment 1). Lastly, we assume that the minimum incentive value adopted would be $7/MWh (the assumed Class I price).

Calculating SACP/Incentive Levels by Policy Case: To translate CREST results into incentive values, we group project types into six Incentive Groups (<=25 kW, Building Mounted, Ground Mounted, Community Solar (CS), Low and Moderate Income (LMI), Preferred Siting). Incentive targets are set for each Incentive Group and policy case by taking a weighted average of the COE of the project types in each Incentive Group, based on their relative market share (found in Attachment 1, slide 38). Each project type's COE is a weighted average of the 3rd-party-owned and host-owned COE, based on historic ownership distributions per project size category. We base all incentive targets off the COE for projects in PSEG, as this service territory represents the bulk of the NJ solar market and is generally the highest cost territory for solar development (given PSEG's lower cent/kWh net metering rate than the other three EDCs).

To construct TI rates for policy paths involving an SREC market, we utilize a linear equation to match the highest cost Incentive Group's COE with the NPV provided by the incentive over the duration of the incentive term. The equation takes a known SACP level during the Kink period and solves for an SACP level after the Kink period that will result in the required TI project NPV (given assumptions regarding the percent of time the market will be at the cap and floor, see Table 7). The NPV of the TI is calculated from a financer's perspective, which assumes reduced revenue per SREC relative to actual expected revenue due to risk. For policy paths involving SREC factors, factors are assigned to each Incentive Group such that the incentive NPV is equal to the group's weighted average COE. For policy paths that do not involve SREC Factors, we create incentives that can support the highest cost Incentive Group to preserve project diversity.

Assessing Implications for Cost Cap by Policy Case: To assess the impact of each policy case on the cost cap, we multiply the incentive rate in each year, per policy case, by the expected production under the TI, per Incentive Group. To calculate the NPV of each policy case, we assume a 7% ratepayer discount rate. To calculate the headroom available under the cost cap in each year, we compute the total cost of NJ's retail electricity, multiplied by the cost cap percentage, less the total cost of Class I under a "business as usual" pathway. ACP payments made under any policy case are assumed to be recycled back to ratepayers. For details on the cost cap inputs, see Attachment 1.

2.2. Define Modeling Cases

Of the infinite policy paths variations, only a subset is modeled. As discussed above in Section 1.6, the four policy path descriptions (presented at the June 14 Stakeholder Workshop and as shown in Table 6) that are the basis for the policy paths modeled for this analysis are:

- TI-1 (Continuation of Legacy SREC with new RPS);
- TI-2 (Factorized SRECs);
- TI-3 (Factorized SRECs w/buyback); and,
- TI-4 (PBIs allocated by market segment).

Per the discussion and findings in Section 1, the Consulting Team in consultation with BPU Staff chose six policy paths to model which are summarized below in Table 7 and are named as variants of policy paths presented at the June 14 Stakeholder Workshop.

Each row of Table 7 is a policy path case that is modeled, and each column summarizes the key attributes of the policy path. Below we describe each of the six modeled cases in more detail.

TI-1a: DO w/ Flat SACP is meant to be a reference case as the closest analogue to the current SREC legacy program (and as the name indicates is a variant of TI-1 presented at the June 14 Stakeholder Workshop). While case TI-1a pre-supposes a new market (i.e., TREC market), it has much the same structure as the legacy SREC market including a *de facto* floor price (the Class I REC price).

The major differences of TI-1a base case from the current legacy SREC program are:

- A 15-year life for all the modeling base cases (including the TI-1a base case) versus a 10-year life for the current legacy SREC program;
- A flat SACP for the TI-1a base case versus a declining SACP for the current legacy SREC program. A flat SACP for TI-1a was employed to ameliorate the cost cap constraints of the Kink years in EY 2022 and 2023.[18] If TI-1a had a declining SACP throughout the program life (starting in EY 2021), it would result in higher SACPs in the early years to provide the equivalent discounted incentive revenue stream to projects that would result from a flat SACP; and,
- The price level of the SACP set based upon the analysis of currently forecasted LCOE.

[18] In order for the NPV of TI revenue to match the COE of projects under a declining SACP, the SACP would need to be set higher during the kink-period relative to a policy design that uses a flat SACP. Thus, program-wide TI costs in the kink period would be minimized by a flat SACP that shifts costs to later years with greater cost-cap headroom.

Table 7 – Base Cases of Modeled TI Policy Paths

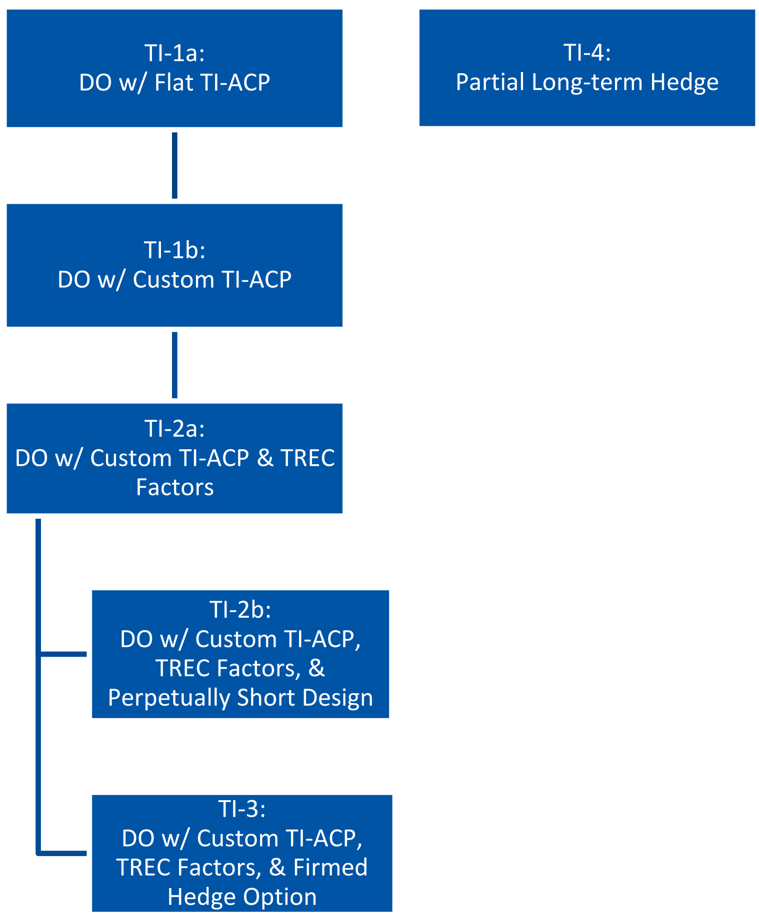
TI Policy Path Nickname	Ratepayer Cost Reduction Features	Incentive Risk Profile	% Years at Cap/Floor (Financier View)	% Years at Cap/Floor (Actual Market Outcome)	Market Floor Type	CREST Cost Profile	Incentive Term (Years)
TI-1a - Demand Obligation (DO) w/ Flat TI-ACP	• TI-ACP (flat, in order to ensure an initial TI-ACP below EY 2021 value for Legacy TREC program) • Firm end date for program 16 years after 1st system online ("Firm Program End Date")	Unhedged Commodity + Incentive	Conservative (40%/60%)	"In Balance" (50%/50%)	Class I REC price	Base	15
TI-1b - DO – w/ Custom TI-ACP	• Reduced TI-ACP through EY 2023 (to accommodate Cost Cap) • Firm Program End Date	Unhedged Commodity + Incentive	Conservative (40%/60%)	"In Balance" (50%/50%)	Class I REC price	Base	15
TI-2a - DO w/ TREC Factors	• Same as TI-1b w/ Differentiated TREC Factors	Unhedged Commodity + Incentive	Conservative (40%/60%)	"In Balance" (50%/50%)	Class I REC price	Base	15
TI-2b - Perpetually Short Design	• Same as TI-2a w/ "Perpetually Short" Design	Unhedged Commodity + Partially Hedged Incentive	Moderate (70%/30%)	Mostly Short (80%/20% Floor)	Class I REC price	Base	15
TI-3 - DO w/ Firmed Hedge Option	• Same as TI-2a w/ Floor Firmed for initial investor via fixed for floating swap PBI hedge option	Unhedged Commodity + Partially Hedged Incentive	N/A (Prices assumed to follow PBI cost to ratepayers from TI-4 + 5% (representing LSE/ EDC markup associated w/ transaction costs)	N/A (See Cell at Left)	Firm Floor set at max COE per project group *(Cost of option represents 100% participation in buyout program)*	Base	15
TI-4 - Partial Long-Term Hedge	• Fixed premium payment (e.g., for RECs) • Reduced PBI payments through EY 2023	Unhedged Commodity/ Hedged Incentive	N/A (Fixed Schedule PBI for RECs)	N/A (Fixed Schedule PBI for RECs)	N/A (Fixed PBI)	Base	15

Case TI-1a also lacks additional attributes which help define the other modeled cases. Those excluded attributes for case TI-1a include:

- TREC Factors;
- Customizing the TI-ACP price levels to get through the budget constraints of the Kink years (i.e., EY 2022 & 2023). That is, dropping the TI-ACP price levels in EY 2022-23 and then raising the TI-ACP price levels thereafter;
- Crafting a Compliance Obligation such that the TREC market was perpetually short; and,
- Firming the floor price with a hedged PBI fixed for floating swap option.

Figure 4 below displays the family tree of the other policy paths and how TI-1b, TI-2a, TI-2b, and TI-3 are all related to and derivative of TI-1a. While these policy paths have many similar features, they result in different levels of SACP and different net ratepayer incentive costs.

Figure 4 – Relationship of TI Modeled Policy Paths



TI-1b: DO w/ Custom TI-ACP is very similar to TI-1a: DO w/ Flat TI-ACP except that TI-1b also employs a custom TI-ACP that is lower during the Kink years to help navigate the cost cap and conversely higher during the post-Kink years to ensure the NPV of the incentive meets incentive requirements for PV development. Note, such a customized TI-ACP price level trajectory would be antithetical to a market open for multiple years, as policy makers and ratepayers hope that the level of incentives will generally decrease over time and would employ a declining block or adjustable block incentive program instead. However, because the TI is only planned to be open to a limited number of projects in the pipeline, the customization of the TACP is just a policy choice of when to pay for the incentives. For TI-1b a greater bulk of the incentive payments are deferred to after the Kink years.

TI-2a: D.O. w/ Custom TI-ACP and TREC Factors is identical in structure to TI-1b (including the customized TI-ACP structure) but in addition includes TREC Factors. That is, instead of every TREC being equivalent to 1 MWh, load serving entities (LSEs, i.e. retail third party suppliers [TPSs] and Basic Generation Service [BGS] suppliers) only would be able to claim a fractional portion of TRECs for compliance depending upon the Incentive Group that the project belongs to.

TI-2b: D.O. w/ Custom TI-ACP, TREC Factors, and Perpetually Short Design is identical in structure to TI-2a, except that with TI-2b the BPU also would set the Compliance Obligation so that it was unattainable. This would result in the market clearing at or very close to the TI-ACP price level. If the methodology to calculate the Compliance Obligation was set by BPU Order, investors had confidence that the market would always be short (because of the initial Compliance Obligation methodology), and investors had confidence that the methodology would not be changed in a future Order, then the TI-ACP price level in each Energy Year would be considered a good proxy for a fixed price PBI, and thus result in lower financing costs. For this policy case to be effective at reducing ratepayer costs, either the Compliance Obligation methodology would have to be sufficiently precise to minimize ACP payments, or ACP payments would have to be recycled back to ratepayers.

TI-3: D.O. w/ Custom TI-ACP, TREC Factors, and Firmed Hedge Option is identical in structure to TI-2a, except that with TI-3 the EDCs would be required to purchase the TRECs at a fixed (PBI) for floating (PBI) swap. For modeling purposes, we assume that at the time of attaining a project's SRP acceptance, the project developer would have a one-time put option; a voluntary opportunity to trade in the PBI of volatile (floating) TREC market prices for a fixed PBI revenue stream backed by the EDCs (i.e., a fixed PBI for floating PBI swap).[19] It is further envisioned that the EDCs would competitively sell the TRECs back to the market and the net revenue (less EDC transaction costs) would be credited or debited to ratepayers via a non-bypassable wires charge.

Finally, as seen in Figure 4 – Relationship of TI Modeled Policy Paths

TI-4: Partial Long-Term Hedge is not related to T1a or its progenitors. TI-4 presumes a fixed premium most likely imposed via an EDC tariff. In practice TI-4 provides the assurance of a fixed PBI just like TI-3,

[19] See Footnote 12. In addition, it is important to note that the ratepayer cost of this option could be higher than initially modeled, since many TI-eligible projects have likely closed financing, and thus may not be able to participate in the hedged option, unless they seek to reprice or refinance their projects.

but without the put option and thus without the upside revenue of a tradeable SREC market.[20] That is, there is no voluntary fixed for floating swap put option (as in TI-3), but only a fixed performance-based incentive (PBI). This modeled case includes a PBI customized for different market segments just as SREC Factors were customized for different market segments for TI-2a, TI-2b, and TI-3 and assumes that the PBI price levels would be customized to negotiate the cost cap of the Kink years as is done with SACP prices levels for TI-1b, TI-2a, TI-2b and TI-3.

2.3. Analysis of Modeling Cost and Deployment Results

An overview of results as they relate to the cost cap and incentive levels is provided in this section. Table 8 displays the NPV of each policy case's direct costs to ratepayers (assuming a 7% discount rate). Yearly costs and additional detailed results can be found in Attachment 2. Results demonstrate that the temporal distribution of costs and the financing implications of each policy case have significant impacts on total program costs.

Table 8 – Net Present Value (NPV) of Direct Ratepayer Costs by TI Policy Path

Case/Sensitivity	Total NPV to Ratepayers ($MM)
TI-1a - DO - Flat TI-ACP (Base Cost - 15 Year)	**$907**
TI-1b - DO - Custom TI-ACP (Base Cost - 15 Year)	**$1,016**
TI-2a - DO w/TREC Factors (Base Cost -15 Years)	**$800**
TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	**$701**
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	**$594-$800†**
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	**$566**
†Represents range of costs based on potential election to receive fixed TREC payments (e.g. if 100% participation in a potential EDC program, cost is at low end of range, and if 0%, at high end of range).	

Table 9 – Net Present Value (NPV) of Direct Ratepayer Costs by TI-2a (DO w/TREC Factors) Sensitivity

Case/Sensitivity	Total NPV to Ratepayers ($MM)
TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	**$835**
TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	**$639**
TI-2a - DO w/TREC Factors (Base Cost -10 Year)	**$728**
TI-2a - DO w/TREC Factors (High Cost - 10 Year)	**$947**

[20] We note that it is possible that some projects in the pipeline that have already been financed with developers assuming an TREC-based structure for the TI may be unable to proceed given incentives designed assuming more certain revenue streams (which command lower financing costs and thus produce lower payment rates).

Figure 5 below provides a graphical depiction of the cost cap headroom under TI-2a including the cost of the legacy SREC program and non-solar/OSW Class I, per energy year.

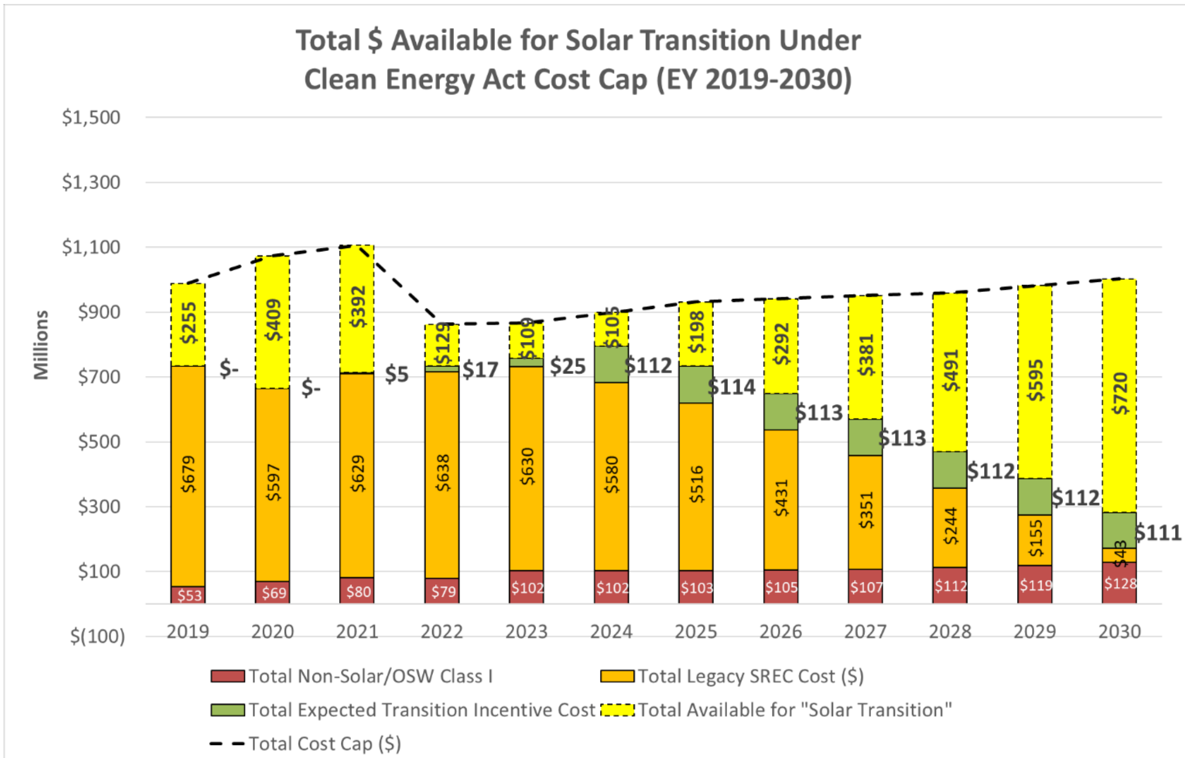
As is apparent, the contraction of the cost cap from 9% to 7% in EY 2022, in combination with high legacy SREC costs, creates the Kink period in which cost-cap headroom is constrained. While enough headroom exists to prevent TI-2a from exceeding the cost cap under our base legacy SREC price outlook, Table 10 shows that under a high price scenario (in which we assume lower legacy SREC supply and higher demand) the cost cap would be exceeded by $73 million in EY 2022. Furthermore, the cost cap is exceeded in every policy case under a high price scenario, demonstrating the uncertainty inherent in the designing policy to accommodate the cost cap.

Table 12 displays the average TI incentive per policy case compared to the average legacy SREC incentive over the same incentive term. Results show that incentives under the TI are comparable or lower than the legacy SREC program under all policy cases involving a hedged incentive but range from modestly to significantly higher for the options with TREC factors and without a partial or total premium/incentive hedge. These higher costs are driven in significant part by the decision to assume PSEG's retail rates when developing gap analysis estimates (as shown by Incentive Group in Table 14 and Table 15).

Finally, Table 16 and Table 17 display TREC Factors (which are the modeled fraction of TRECs / Discount to Highest Cost Incentive Group that could be claimed for compliance purposes) per Incentive Group and policy case. For modeling purposes, TREC factors are not designed to be combined, but rather represent discrete categories that projects may fall into (for the Project Types assigned to each Incentive Group, see Attachment 1). We note that the TREC Factor for LMI projects (which includes LMI CSS projects) is lower than the TREC Factor for CSS projects despite our modeling results showing that the introduction of LMI requirements for a project would increase its cost. This discrepancy is a product of a the "Very Large Building Mounted Community Solar" project type, which has a high COE, being included in the average incentive requirement for the CSS Incentive Group. The LMI Incentive Group does not have a comparably very large project type with a comparably high COE. TREC factors for the <= 25 kW Incentive Group vary significantly between cost cases as these project's lower total cost result in small changes in installed cost assumptions having a larger relative effect on the project's incentive requirements. In addition, these projects do not have certain fixed costs associated with them (e.g., land lease and project management costs), which results in variance in cost assumptions having a more direct effect on the overall incentive requirement. Finally, the installed cost data that informed our cost cases revealed greater variance for the <=25 kW Incentive Group.

Any funds remaining under the cost cap, after payment of the total non-solar/OSW Class I obligations, the total Legacy SREC cost, and the total expected TI cost, would be the "head-room" available to be disbursed as incentive payments under a Successor Program (see Figure 5 for an example of how to determine this headroom level). TI policy paths that meet or exceed the cost cap may risk precluding the implementation of a Successor Program. At this stage, our modeling does not include any analysis or forecasting of the Successor Program.

Figure 5 – Cost Cap Headroom by Energy Year (TI-2a - DO w/TREC Factors, Base Cost -15 Years)[21]



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[21] Assumes the base headroom scenario which includes the base forecast for Legacy SREC prices.

Table 10 – Clean Energy Act Class I Cost Cap Headroom During "Kink" Period by Policy Case (EY 2021-2024, $ in Millions)

Cases and Sensitivities (Cost Profile & Incentive Term)	Legacy SREC Cost Outlook	EY 2021 (9% Cost Cap)	EY 2022 (7% Cost Cap)	EY 2023 (7% Cost Cap)	EY 2024 (7% Cost Cap)
TI-1a - Demand Obligation (DO) - Flat TI-ACP (Base Cost - 15 Year)	Base	$382	$91	$45	$103
	High	$274	($111)	($101)	$26
TI-1b - DO w/Custom TI-ACP (Base Cost - 15 Year)	Base	$391	$125	$103	$75
	High	$282	($78)	($42)	($3)
TI-2a - DO w/TREC Factors (Base Cost -15 Years)	Base	$392	$129	$109	$105
	High	$284	($73)	($36)	$27
TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	Base	$393	$130	$111	$122
	High	$284	($72)	($34)	$45
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	Base	$393	$131	$112	$135
	High	$284	($72)	($33)	$57
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	Base	$393	$131	$113	$138
	High	$284	($71)	($32)	$61

Table 11 – Cost Cap Headroom During "Kink" Period by TI-2a (DO w/TREC Factors) Sensitivity (EY 2021-2024, $ in Millions)

Cases and Sensitivities (Cost Profile & Incentive Term)	Legacy SREC Cost Outlook	EY 2021 (9% Cost Cap)	EY 2022 (7% Cost Cap)	EY 2023 (7% Cost Cap)	EY 2024 (7% Cost Cap)
TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	Base	$393	$132	$113	$118
	High	$284	($71)	($32)	$40
TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	Base	$393	$132	$113	$142
	High	$284	($71)	($32)	$65
TI-2a - DO w/TREC Factors (Base Cost -10 Year)	Base	$388	$113	$86	$84
	High	$279	($89)	($59)	$6
TI-2a - DO w/TREC Factors (High Cost - 10 Year)	Base	$387	$111	$83	$40
	High	$278	($92)	($63)	($37)

Table 12 – Average TI Incentive vs Legacy SREC Incentive by Policy Case

Cases and Sensitivities (Cost Profile & Incentive Term)	Levelized Legacy SREC $/MWh Over TI Term (2019 COD)	Levelized Legacy SREC $/MWh Over TI Term (2020 COD)	Weighted Avg TI NPV ($/MWh)	% Change from 2019 COD Legacy SREC (%)	% Change from 2020 COD Legacy SREC (%)
TI-1a - Demand Obligation (DO) - Flat TI-ACP (Base Cost - 15 Year)	$131	$116	$175	33%	51%
TI-1b - DO w/Custom TI-ACP (Base Cost - 15 Year)	$131	$116	$175	33%	51%
TI-2a - DO w/TREC Factors (Base Cost -15 Years)	$131	$116	$138	5%	19%
TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	$130	$115	$118	-9%	3%
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	$130	$115	$105	-20%	-9%
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	$130	$115	$100	-23%	-13%

Table 13 – Average TI Incentive vs Legacy SREC Incentive by TI-2a (DO w/SREC Factors) Sensitivity

Cases and Sensitivities (Cost Profile & Incentive Term)	Levelized Legacy SREC $/MWh Over TI Term (2019 COD)	Levelized Legacy SREC $/MWh Over TI Term (2020 COD)	Weighted Avg TI NPV ($/MWh)	% Change from 2019 COD Legacy SREC (%)	% Change from 2020 COD Legacy SREC (%)
TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	$114	$101	$125	10%	24%
TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	$114	$101	$97	-15%	-4%
TI-2a - DO w/TREC Factors (Base Cost -10 Year)	$162	$147	$167	3%	14%
TI-2a - DO w/TREC Factors (High Cost - 10 Year)	$162	$147	$212	31%	45%

Table 14 – 2019 Weighted Average Levelized Incentive Gap for PSEG by Policy Case

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
TI-1a - Demand Obligation (DO) - Flat TI-ACP (Base Cost - 15 Year)	$141	$141	$113	$110	$84	$32
TI-1b - DO w/Custom TI-ACP (Base Cost - 15 Year)	$141	$141	$113	$110	$84	$32
TTI-2a - DO w/TREC Factors (Base Cost -15 Years)	$141	$141	$113	$110	$84	$32
TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	$134	$132	$107	$103	$78	$16
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	$134	$132	$107	$103	$78	$16
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	$128	$127	$103	$99	$74	$10

Table 15 – 2019 Weighted Average Levelized Incentive Gap for PSEG by TI-2a (DO w/ SREC Factors) Sensitivity

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	\$128	\$129	\$102	\$99	\$76	\$29
TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	\$101	\$101	\$80	\$77	\$59	\$7
TI-2a - DO w/TREC Factors (Base Cost -10 Year)	\$171	\$169	\$138	\$134	\$102	\$41
TI-2a - DO w/TREC Factors (High Cost - 10 Year)	\$216	\$211	\$176	\$174	\$129	\$101

Table 16 – TREC Factors (or Fractional Fixed REC Payments) by Policy Case[22]

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
TI-1a - Demand Obligation (DO) - Flat TI-ACP (Base Cost - 15 Year)	1.00	1.00	1.00	1.00	1.00	1.00
TI-1b - DO w/Custom TI-ACP (Base Cost - 15 Year)	1.00	1.00	1.00	1.00	1.00	1.00
TI-2a - DO w/TREC Factors (Base Cost -15 Years)	1.00	1.00	0.80	0.78	0.59	0.23
TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	1.00	0.99	0.80	0.77	0.58	0.12

[22] The TI-1a and TI-1b design options do not utilize TREC factors but are included in this table to clarify that all TRECs generated under each policy design would receive a 1:1 credit value.

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	1.00	0.99	0.80	0.77	0.58	0.08
TI-3 - DO w/TREC Factors & Firmed Hedge Option (Base Cost - 15 Year)	N/A, policy case assumes 100% participation in firmed hedge option. Thus, fixed incentive levels would be equal to TI-4. Otherwise, TREC Factors would be equal to TI-2a.					

Table 17 – Cost-Based TREC Factors for TI-2a (DO w/TREC Factors) Sensitivities

Incentive Group → Cases and Sensitivities (Cost Profile & Incentive Term)↓	Preferred Siting	Building Mounted	Community Solar	LMI	Ground Mounted	<=25 kW
TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	0.99	1.00	0.79	0.77	0.59	0.23
TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	1.00	1.00	0.79	0.76	0.58	0.07
TI-2a - DO w/TREC Factors (Base Cost -10 Year)	1.00	0.99	0.81	0.78	0.60	0.24
TI-2a - DO w/TREC Factors (High Cost - 10 Year)	1.00	0.97	0.82	0.80	0.60	0.47

2.4. Implementation Issues that May Impact Feasibility of Modeled Options

Table 18 displays a summary of the perceived level of difficulty of a variety of major issues that some or all the proposed TI policy cases would have to overcome, based upon the Consulting Team's experience and understanding of solar incentive programs both in New Jersey and in other states. In addition, Table 19 describes the implementation issues and challenges for the various TI policy cases.

Table 18 – Perceived Difficulty Level of Implementation Issue (N/A=Not an Issue, 1=Very Easy, 5=Very Difficult)

TI Policy Case Nickname → Implementation Issue / Challenge	TI-1a - DO w/Flat TI-ACP	TI-1b – DO w/ Custom TI-ACP	TI-2a - DO w/ TREC Factors	TI-2b - Perpetually Short Design	TI-3 - DO w/ Firmed Hedge Option	TI-4 - Partial Long-Term Hedge
Setting a Compliance Obligation schedule / algorithm that keeps the market in balance for the life of the program	5	5	5	N/A	5	N/A
Setting a Compliance Obligation schedule / algorithm that keeps the market in perpetual shortage	N/A	N/A	N/A	3	N/A	N/A
Setting capped price level (TI-ACP or Long-Term Hedge)	3	4	4	3	4	3
Setting TREC Factors / differentiated incentive levels	N/A	N/A	3	3	3	3
Including TREC Factors into the LSE CO calculation	N/A	N/A	3	3	3	N/A
Identifying and working with parties offering a hedge	N/A	N/A	N/A	N/A	5	5
Educating stakeholders / market participants of new market construct	1	2	3	4	5	4
Recycling TI-ACP revenue to ratepayers	2	2	2	4	2	N/A
Getting stakeholder buy-in	2	2	2	4	5	2
Flexibility of potential extension of TI past 5.1% milestone	2	2	2	3	4	4

Table 19 – Discussion of TI Policy Case Implementation Issues & Challenges

Implementation Issue / Challenge	Discussion
Setting a Compliance Obligation (CO) schedule / algorithm that keeps the market in balance for the life of the program	Setting a CO is relatively easy (or at least is an issue the BPU has confronted and resolved). Setting a CO schedule to keep a "closed" market in balance over the life of the program is very difficult; the BPU has been wrestling with similar issues with the upcoming closure of the legacy SREC market. The TI market will close soon after it opens with a complicated to estimate level of participation. None of the policy cases included explicit CO adjustment mechanism as they were deemed too complicated to implement prior to setting up a TI. Given these constraints, we suggest that, when setting up the TI, the BPU explicitly reserves the right to adjust the CO schedule under certain circumstances (e.g., perpetual short market, perpetual long market).
Setting a Compliance Obligation schedule / algorithm that keeps the market in perpetual shortage	Setting a CO to keep the market in perpetual shortage is simpler than keeping it in perpetual balance: Calculate the annual TREC production each year by multiplying the MW that will participate, the capacity factors, degradation rate and as applicable SREC Factors to calculate a CO. Divide by the estimated annual load to be served to calculate a Minimum Standard (MS). Multiply each of the annual (10, 15, or 20 years) COs and MSs schedules by 2 ("Shortage Insurance Multiplier"). This will produce a CO and MS schedule that almost certainly will keep the market in perpetual shortage because the CO for each year is twice as large as the estimate to perfectly match TREC supply and demand. While the above calculation is easier, it is also very conservative and will increase ratepayers bills by much more than is likely necessary to keep the market in perpetual shortage. The more difficult implementation issues relate to balancing the above proposed conservatism of the Shortage Insurance Multiplier with precision. Will setting the Shortage Insurance Multiplier at 1.5 or 1.25 instead of 2 provide enough market certainty that the market will be perpetually short? Can the Shortage Insurance Multiplier have a stop gap where if banked TRECs are calculated to be more than X% (200%, 300%) the following year's CO requirement the Shortage Insurance Multiplier adjusts downward (even possibly below 1.0)?
Setting capped price level (TI-ACP or Long-Term Hedge)	Setting a capped price level appropriately so it does not provide extraordinary economic returns above the required rates of return for robust market participation, while not being so low as to squelch market participation is difficult. Nonetheless, the analysis provided herein makes estimates of required incentive levels through its gap analysis modeling.
Setting TREC Factors / differentiated incentive levels	The trade-off of overpaying for extraordinary rates of return vs. market viability is also an issue for setting SREC Factors / differentiated incentive levels. An additional issue is how coarse or fine to make the incentive differentiation. Should TREC Factors / incentive levels vary by project type and size? Should they vary by EDC as well? What about offtaker? Should there be a higher TREC Factors for Community Solar

Implementation Issue / Challenge	Discussion
	projects with a minimum percentage of low-to-moderate income offtakers? Or how about higher TREC Factors for low-to-moderate income host owned residential systems?
Including SREC Factors into the LSE CO calculation	To implement this option, either: 1) PJM GATS must factorize TRECs within the TI timeframe. 2) If PJM GATS is not able to factorize TRECs, factorizing TRECs must be incorporated into the calculation of each LSE's CO calculation. To implement, the following major issues need to be addressed. First – PJM GATS would need to tag each TREC via additional fields of the appropriate information for calculating the TREC Factor (e.g., Project Type, Project Size, Project Offtakers, etc.) so factor adjustments to the TREC are known by the TREC owner (and potential buyers). Second – The same fields would need be validated and appear in the SRP. Third – For annual LSE compliance calculation, the BPU would need to calculate the CO with TREC Factors.
Identifying and working with parties offering a hedge	A large credit worthy entity would need to provide the hedge which would be needed to implement TI-3 and TI-4. The EDCs are the most likely offtakers and almost certainly the only entity the BPU could work with to provide a financial hedge in the timeframe of the TI. Even so, the development of the Three EDC SREC Purchase Program took 6 months, received pushback from stakeholders, was not easy to implement, had high transaction costs, high EDC returns and low participation rates (and did not include PSEG, the largest NJ EDC). In addition, the timeline between issuance of an RFP and the announcement of the awarding of the bids for the Three EDC SREC Purchase Program was four months and the actual contract execution another 45 days (see Request for Proposals ("RFP") Under the SREC-Based Financing ("SREC-II") Program: ROUND 9 OF 9, page 10). The maximum benefits of offering a hedge is to offer it to all participants. The EDC SREC Purchase Program had capped participation. It is unclear if the EDCs would be comfortable with a more widespread program.
Educating stakeholders/market participants of new market construct	Whatever combination of program attributes are chosen for the TI, stakeholders (and the public) will need to be educated about them and how the TI will work. The more like the current SREC legacy program, the easier this task will be.
Getting stakeholder buy-in	While any policy chosen will be critiqued by some, the solar industry would almost universally balk at any TI policy that could not be articulated and implemented swiftly and efficiently, as expressed by stakeholders in SWS 1 and SWS2. Conversely, ratepayers and their advocates will oppose policies that do not try to minimize ratepayer costs. Thus, choosing a relatively high cost but simple to execute policy is likely to meet ratepayer opposition.
Recycling SACP revenue to ratepayers	Except for TI-4 (Partial Long-Term Hedge), all the other cases are based on a demand obligation and therefore each includes an TI-ACP. Currently the SACP legacy revenue gets swept into the general fund.

Implementation Issue / Challenge	Discussion
	Previously legacy SACP revenue was allocated to the NJCEP. Theoretically, TI-ACPTI-ACP revenue also could be recycled back to ratepayers via a distribution charge credit. In most cases where we expect the TREC supply to approximate the TREC demand, the disposition of TI-ACPTI-ACP revenue would be a secondary issue. In fact, our modeling assumes recycling TI-ACPTI-ACP revenue to ratepayers and thus presumes TI-ACPTI-ACP payments by ratepayers do not increase net ratepayer costs. Case TI-2b explicitly breaks the assumption that TREC supply and demand would be nearly in balance during the term of the TI. Thus, if case TI-2b were implemented it would be much more important to either explicitly require TI-ACPTI-ACP revenue to be returned to ratepayers or to account for TI-ACPTI-ACP revenue as ratepayer costs which would accrue against the rate cap.
Flexibility of potential extension of TI past 5.1% milestone	While it would likely increase the costs of the TI program, the BPU has left open the option, if necessary, that the commencement of the TI may extend past the 5.1% of load served by solar milestone if the SP is not implemented at the time the Board determines that the 5.1% Milestone has been attained. If such an extension were only a handful of months, then the largest impact would be on setting of the Compliance (CO) demand level. All things being equal, the CO would have to increase to consider the increased MW that would qualify for the TI and the probability of breaching the cost cap would increase. If such an extension were to prolong the TI for a year or more, then the assumptions of the COE would become less and less reliable over time. With less reliable COE estimates, the probability would increase of either over compensating projects because of overly lucrative incentives or conversely grinding the market to a halt because of incentives that did not provide sufficient compensation for investment and development. In addition, if the TI were to include a hedge (i.e., TI-3 or TI-4), the possibility of a TI extension would have to be considered when crafting the specific policy.

3. Ranking and Recommendations of Transition Incentive Options

3.1. *Ranking Options Based Solely on Modeled Results*

While the costs of the Legacy SREC program remain the dominant factor in determining whether the Clean Energy Act's Class I Cost Cap is breached, the results of our analysis strongly suggest that options that reduce applicable TI-ACPs (or reduce fixed PBIs, in the case of TI-4) during the Kink period of 2021-2023 could reduce the cost of the TI and the risk that the TI leads to the breach of the Cost Cap. As shown in Table 10 above, the cases with reduced TI-ACPs result in significantly lower Kink period headroom.

It is also important to note that, when utilizing a reduced TI-ACP (or reduced fixed PBI) during the Kink period, it would be necessary for projects to receive substantially more revenue during the post-Kink period (2024 and thereafter). Raising the TI-ACP (or fixed PBI) to a substantially higher-level post-Kink would ensure that projects receive sufficient revenue to produce an appropriate return to their debt and equity investors following a period in which projects receive less on a levelized basis than is necessary to make that return. The net effect of this design means that the net present cost to ratepayers of options that include reduced Kink period TI-ACPs to New Jersey ratepayers is higher than those in which payments are level (TI-1a).

In this section, we provide an overview of results as they relate to the cost cap and incentive levels. Table 20 displays the NPV of each policy case's direct costs to ratepayers (assuming a 7% discount rate[23]). Yearly costs and additional detailed results can be found in Attachment 2. Results demonstrate that the temporal distribution of costs and the financing implications of each policy case have significant impacts on total programmatic costs. The net effect of this design means that the overall NPV of such reduced Kink period TI-ACPs (and subsequent revenues to solar projects) to New Jersey ratepayers is higher. For example, as shown in Table 20, the NPV of the cost to ratepayers of the TI-1a - Flat TI-ACP option (in which neither TI-ACPs nor assumed average revenue during the project life vary from year to year) is $109 million ($907 million vs. $1,016 million) less than the TI-1b - Custom STCP (in which the only difference from TI-1a is a reduced TI-ACP during the Kink period and a higher TI-ACP thereafter).

To account for the importance of mitigating both Kink period and overall ratepayer NPV costs, we have developed rankings of each policy path based on:

- The overall Cost Cap headroom of each policy case in EY 2022 (the year in which the Cost Cap contracts from 9% to 7% of the "total paid for electricity"); and

[23] Discount rate represents ratepayer discount value utilized in Optimal Energy. *Energy Efficiency Potential in New Jersey*. 24 May 2019. Prepared for the New Jersey Board of Public Utilities (BPU). Available at: https://s3.amazonaws.com/CandI/NJ+EE+Potential+Report+-+FINAL+with+App+A-H+-+5.24.19.pdf

- The overall NPV of TI compliance for each policy case to ratepayers.

Table 20 below illustrates these rankings, as well as the EY 2022 headroom under Base and High Legacy SREC Cost conditions and the overall NPV of Class I compliance for each option:

Table 20 – Ranking of Policy Paths Based on Cost Cap Headroom and NPV of Ratepayer Costs (with Base Costs and 15-Year Incentive Durations Assumed)

EY 2022 Headroom Rank	Case/Sensitivity	EY 2022 Headroom ($MM)†	NPV Rank	Case/Sensitivity	NPV ($MM)
1	TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	**$131.4 / ($71.0)**	1	TI-4 - Partial Long-Term Hedge (Base Cost - 15 Year)	**$566**
2	TI-3 - DO w/TREC Factors and Firmed Hedge Option (Base Cost - 15 Year)	**$130.7 / ($71.7)**	2	TI-3 - DO w/TREC Factors and Firmed Hedge Option (Base Cost - 15 Year)	**$594**
3	TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	**$130.4 / ($72.1)**	3	TI-2b - DO w/ TREC Factors & Perpetually Short Design (Base Cost - 15 Year)	**$701**
4	TI-2a - DO w/TREC Factors (Base Cost -15 Year)	**$129.0 / ($73.4)**	4	TI-2a - DO w/TREC Factors (Base Cost -15 Year)	**$800**
5	TI-1b – DO - Custom TI-ACP (Base Cost - 15 Year)	**$124.6 / ($77.8)**	5	TI-1b – D.O. - Custom TI-ACP (Base Cost - 15 Year)	**$907**
6	TI-1a – DO - Flat TI-ACP (Base Cost - 15 Year)	**$91.3 / ($111.2)**	6	TI-ACP TI-1a – D.O. - Flat TI-ACP (Base Cost - 15 Year)	**$1,016**

† Figures represent Base and High Legacy TREC Cost Outlook cases

To most appropriately account for the interplay of the Kink period impact and overall cost of each option, we have developed an average ranking that accounts for the Cost Cap headroom and NPV ranks, respectively (shown in below).

To this end, we find that TI-4 (the long-term hedged TREC option) provides the greatest headroom under the Cost Cap and the lowest overall cost to ratepayers relative to the "status quo" options (represented by the TI-1a and TI-1b). Similarly, TI-3 (the firmed hedge option) provides materially greater Cost Cap headroom than a traditional SREC-style approach, as well as lower ratepayer costs. While the "perpetually short" option with TREC Factors (TI-2b) offers substantially lower overall ratepayer costs, it provides limited additional headroom relative to the more straightforward demand obligation-style program with TREC Factors (TI-2a), despite having a much lower TI-ACP during the

"Kink" period.[24] However, relative to the "status quo" options, adding SREC Factors provides the most substantial increase in both Cost Cap headroom and reduction in ratepayer NPV of all the potential modifications to the policy paths under consideration.

Table 21 illustrates the TI-2aTable 21 – Cost Cap Headroom and NPV Results for TI-2a (DO w/TREC Factors) Sensitivities

Headroom Rank	Case/Sensitivity	EY 2022 Headroom ($MM)[1]	NPV Rank	Case/Sensitivity	NPV ($M)
1	TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	**$132.5 / ($69.9)**	**1**	TI-2a - DO w/TREC Factors (Low Cost - 20 Year)	**$639**
2	TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	**$132.3 / ($70.2)**	**2**	TI-2a - DO w/TREC Factors (Base Cost -10 Year)	**$728**
3	TI-2a - DO w/TREC Factors (Base Cost -10 Year)	**$114.7 / ($87.7)**	**3**	TI-2a - DO w/TREC Factors (Base Cost - 20 Year)	**$835**
4	TI-2a - DO w/TREC Factors (High Cost - 10 Year)	**$112.2 / ($90.2)**	**4**	TI-2a - DO w/TREC Factors (High Cost - 10 Year)	**$941**

The 10-year duration sensitivities show that while such incentives are less costly to ratepayers long-term (assuming the same cost profile and approach to customization of the SACP across multiple incentive durations), they are far less compatible with of the statutory requirement to avoid a breach of the Cost Cap during the high-risk Kink period.

3.2. Legacy SREC Program Close Out Issues that Impact the TI

In addition to the implementation issues discussed in Section 2.4, the 5.1% milestone defines the close of the Legacy SREC program and the start of the TI and thus affects the following:

The Legacy SREC program supply / demand balance. All things being equal, the later the 5.1% milestone is pushed out, the greater the participation in the Legacy SREC program, the greater supply of Legacy SRECs, and the lower Legacy SREC prices. As Legacy SREC prices are the single largest variable affecting the aggregate ratepayer costs accounted under the cost cap, how the 5.1% milestone is determined to be attained is the single largest uncertainty associated with the long-term cost of the Legacy SREC program. It is likely that the method by which 5.1% is deemed attained will have a profound effect on Legacy SREC prices, which could affect the viability of certain TI policies.

The MW participation in the TI. This impacts the cost of the TI. Assuming as we do (see discussion in Section 1.2) that the SP commences upon attainment of the 5.1% milestone, we can expect some partial cost netting depending on the 5.1% attainment milestone methodology. For example, the later the 5.1%

[24] This occurs in part because the "perpetually short" design would assume more years at the SACP than at the floor (which we assume to be Class I REC prices).

milestone is deemed to have been attained, the more MW in the Legacy SREC program. Depending on the assumed application rate and flow of <=25 kW project coming online a change in the 5.1% milestone date could increase or decrease the number of MW that qualify for the TI. The converse is true as well.

The Setting of the Compliance Obligation and Minimum Standard for the TI. The BPU must consider how to set up an SREC-based Transition market with specific compliance obligations (COs) and minimum standards (MSs) [25] when the amount of capacity in the SRP pipeline will not be known definitively until the 5.1% threshold is hit. If the determination of the 5.1% milestone attainment methodology is delayed until after the TI program is announced, it will make the setting of the TI COs and MSs that much more difficult. The BPU could consider determining an estimated number of TI-eligible projects (as well as the expected rate at which such projects will either drop out or reach commercial operation (and when commercial operation will take place) prior to officially determining that the 5.1% threshold has been hit. To do so, it may be possible (as was undertaken by the Massachusetts Department of Energy Resources (DOER) in SREC II) to set the CO based on a formula to calculate compliance obligations based on actual and predicted online projects.

3.3. Implication of Transition Incentive Choice on Successor Program Options

While the TI policy that is chosen does not theoretically rule out any SP options, in practice it may well do so. Referring back to Figure 4, the Consulting Team makes the following findings in regard to the types of policy paths ruled out by selecting a given policy path:

- The **choice of policy case TI-1a** (w/ Flat SACP) or **TI-1b** (w/ Custom SACP) probably does not rule out any SP policy model approaches;
- The choice of any of the policy cases with SREC Factors **TI-2a** (w/SREC Factors), **TI-2b** (w/SREC Factors & Perpetually Short Design), or **TI-3** (w/SREC Factors & Firmed Hedge Option) probably rules out TI-1a and TI-1b for the SP because once a program uses SREC Factors, it will be difficult to not employ SREC Factors in the future;
    - The **choice of policy case TI-2b** may not in practice rule out any additional options for the SP because the perpetually short design is an unorthodox variant only practically plausible for a program with a short acceptance period (or for a DO program that covers a relatively insignificant portion of renewable incentive spending in a state). Nonetheless, the choice of TI-2b will make the market more familiar and probably interested in a more formal long-term hedge for the SP;

[25] In the context of renewable portfolio standards, a minimum standard is a percentage of total load to which a given obligation (such as a renewable portfolio standard or renewable portfolio standard carve-out) applies, whereas a compliance obligation is the total and specific number of SRECs needed to fulfill the minimum standard (which can be derived by multiplying the total load by the minimum standard).

- Like policy case TI-2b, the **choice of policy case TI-3** may not in practice rule out any additional options for the SP, though again like TI-2b it likely will make the market more familiar and more interested in a policy that provides a hedge for the SP (i.e., TI-3 or TI-4);

- Finally, the **choice of policy case TI-4** the partial long-term hedge likely rules out the return to any DO incentive model (i.e., TI-1a, TI-1b, TI-2a, TI-2b, and TI-3).

3.4. Recommendations of Options for Transition Incentive

There are two major choices to be made for the TI.

1. The type of policy case variant
2. The length of the duration of the incentive

As described in more detail next, via a process of elimination, we recommend TI 2a (Demand Obligation w/TREC Factors to be the policy case variant chosen and to be conservative in regard to breaching the cost cap we recommend the duration of the incentive term to be longer (e.g., 20 years) rather than shorter (e.g., 10 years).

3.4.1. Process of Elimination for Choosing a TI Policy Case

As discussed in Section 2.4, implementing any type of hedge option will be challenging during the TI timeframe. Thus, we have a difficult time recommending the BPU pursue a policy case like TI-4 and TI-3. If the BPU believes implementing TI-3 or TI-4 is viable, then we recommend moving ahead with either of them.

We also have a difficult time recommending TI-1a and TI-1b when inclusion of SREC Factors is the only hurdle to saving ratepayers hundreds of millions of dollars on an NPV basis.

That leave policy cases TI-2a and TI-2b as preferable to TI-1a, TI-1b, TI-3 and TI-4 as a choice for the TI. Table 22 displays a comparison of the implementation issues for policy cases TI-2a and TI-2b. While the unorthodox TI-2b is intriguing, it may have a fatal flaw as is emphasized in Table 22 that TI-2b requires convincing financiers that future Boards would not countermand the intent of the perpetual short structure, but a current Board cannot bind the hands of a future Board's decisions. If the BPU believes it could navigate this barrier then we would recommend TI-2b, otherwise TI-2a the policy case using the current demand obligation construct with a customized SACP to navigate the Kink years' budget constraint and implementation of SREC Factors is our recommended choice of a TI policy case for the BPU Staff to work from as it develops a Transition Incentive policy recommendation for the Board.

Table 22 – Comparison of Implementation Issues for TI-2a and TI-2b

Issue	Pro TI-2a: w/ SREC Factors	Pro TI-2b: w/ Perpetually Short Design
Ratepayer costs	TI 2B lower net costs relies on the TREC TI-ACP revenue being returned to ratepayers. While the BPU apparently has the right to Order returning TREC TI-ACP revenue to ratepayers, the legislature may pass a law sweeping TREC TI-ACP revenue into the general fund as it currently does with SREC legacy SACP funds.	TI-2B has lower modeled (and theoretical) net ratepayer costs than TI-2A.
TI-2b, to be successful, must convince investors and financiers that the market would be kept in perpetual shortage.	TI-2b Relies on market perceptions from financiers that the market would be maintained in perpetual shortage by the BPU. This seems unlikely as the present Board cannot bind the hands of a future Board.	
TI-2b, requires maintaining a market in Perpetual Shortage is not the norm	The idea of setting the TREC market so it is never in balance on purpose is complicated to implement at a reasonable incentive levels (and cost to ratepayers)	
How to set-up a TI TREC market that will be quickly closed so that it is always / usually be in balance for TI-2a, or always / usually in shortage for TI-2b		Setting unattainable Compliance Obligation levels is much easier to get right to cause a "perpetual shortage" inherent in the TI-2b structure versus setting the Compliance Obligation schedule correctly for the next 10, 15, 20 years in order to attain a market that is more or less "in-balance", an implicit goal of TI-2a.

3.4.2. Incentive Duration Recommendation for the TI

Within option TI-2a, the Consulting team has developed a series of scenarios. The choice of incentive term (e.g., 10, 15 or 20 years) is a trade-off between the probability of breaching the Kink year budget cap (which militates for a longer term) and NPV of rates (which militates for a shorter term). This decision may be better informed by further analysis of the price of SRECs during the Kink period

(EY2022-24). However, currently the Consulting Team recommends a conservative approach, with the adoption of a 20-year term to minimize the risk of breaching the Cost Cap.

Appendix A. SWS2 TI Policy Path Rankings by Breakout Group

The consultants ranked the stakeholder preferences across the four breakout groups and applied three materially different weighting mechanisms to the votes to test the sensitivity of the project ranking to the ranking method used (Options X, Y, Z, see Table 23).[26] The numeric rankings, which proved to be robust across the different ranking options, are shown in Table 24.[27] Rankings by breakout group are provided in Table 25.

Table 23 - Weighting Options for Stakeholder Voting on TI Policy Paths

Weights	Option X	Option Y	Option Z
Top Choice	3	5	3
Second Choice	2	3	2
Third Choice	1	1	1
Should not be used	-2	-1	-5

Table 24 - Summary of SWS2 Weighted Stakeholder Voting on TI Policy Paths

Rank Using:	TI-1	TI-2	TI-3	TI-4	TI-5	TI-6	TI-7
Option X	5	1	2	4	6	3	7
Option Y	4	1	2	5	6	2	7
Option Z	4	1	2	3	6	5	7

[26] The stakeholders provided ordinal preferences. There are an infinite number of combination of weights that could be applied to the ordinal preferences to result in a cardinal score. Table 6 provides three materially different examples of weights that could be applied to provide an indication of the robustness ranking the preferences.

[27] It is important to note that this summary reflects only the opinions of those stakeholders present at the workshop, a majority of which were from the solar industry. Care should therefore be taken in drawing conclusions from the results presented below. Additional stakeholder engagement may be required to obtain a more complete picture of the positions and recommendations of other relevant stakeholders not present at the SWS1.

Table 25 – Policy Path Rankings by Breakout Group

First Choice	TI Policy Path						
Breakout Group	TI-1	TI-2	TI-3	TI-4	TI-5	TI-6	TI-7
A	3	0	4	4	0	0	3
B	9	5	0	1	0	0	0
C	0	7	2	0	1	0	0
D	2	8	0	0	1	0	0

Second Choice	TI Policy Path						
Breakout Group	TI-1	TI-2	TI-3	TI-4	TI-5	TI-6	TI-7
A	2	2	4	4	1	1	0
B	4	8	2	0	1	0	0
C	1	0	6	0	0	3	0
D	7	2	0	0	1	1	0

Third Choice	TI Policy Path						
Breakout Group	TI-1	TI-2	TI-3	TI-4	TI-5	TI-6	TI-7
A	3	5	1	2	1	1	1
B	0	4	5	4	1	1	0
C	0	0	0	9	0	1	0
D	1	0	7	0	0	0	0

Remove	TI Policy Path						
Breakout Group	TI-1	TI-2	TI-3	TI-4	TI-5	TI-6	TI-7
A	1	2	0	0	1	0	9
B	0	1	0	0	1	4	5
C	0	1	0	0	0	0	3
D	0	0	0	0	0	2	5

New Jersey Solar Performance Analysis

Prepared at the Request of the New Jersey Clean Energy Program

February 1, 2019

pjm | EIS
Environmental Information Services

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Table of Contents

Background

This report was prepared by PJM Environmental Information Services, Inc. ("PJM EIS") at the request of the New Jersey Board of Public Utilities ("NJ BPU").

On May 23, 2018, New Jersey Governor Phil Murphy signed the Clean Energy Act, which directs the BPU to adopt rules and regulations to close the Solar Renewable Energy Certificate (SREC) program to new applications upon the attainment of 5.1 percent of the kilowatt-hours sold in the State. In January 2019, the NJBPU requested that PJM EIS prepare a report of the solar performance (in kWh per kW installed or MWh/MW installed) by year for the last 5 years for NJ solar facilities up to 10 kW, up to 100 kW, up to 1 MW and over 1 MW. The information in this report is expected to provide insights in support of the process for developing the Solar Transition and Successor Program, as required by the Clean Energy Act.

Executive Summary

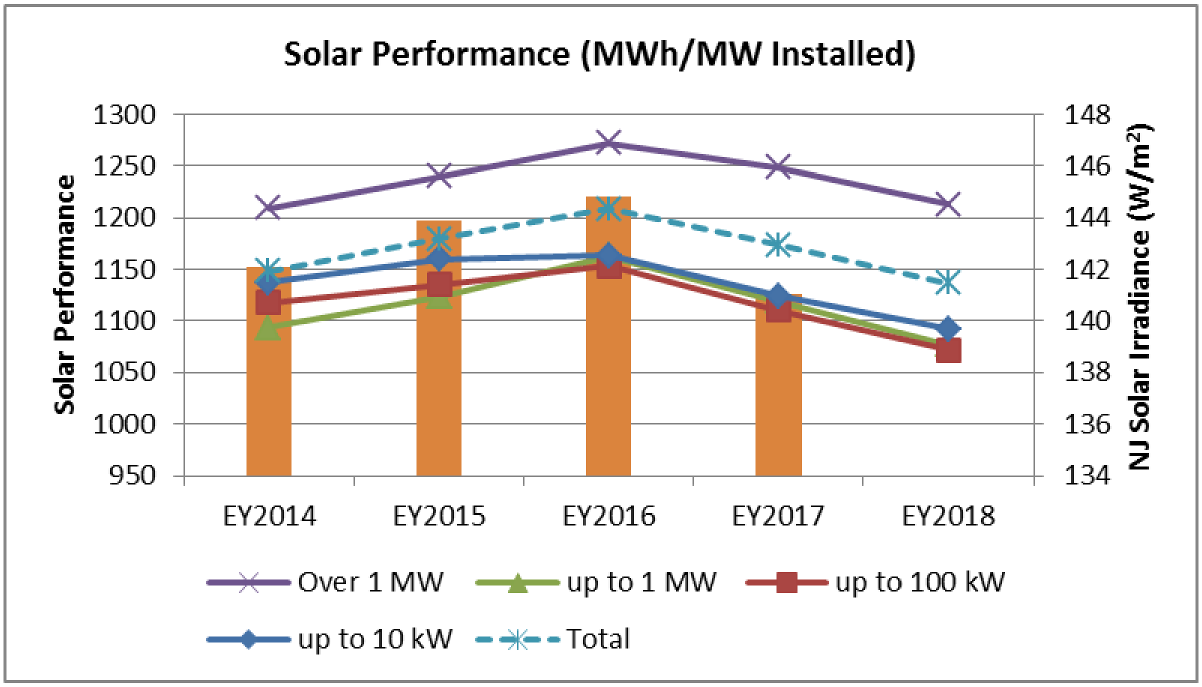
PJM EIS performed an analysis of solar performance for those facilities registered in the Generation Attribute Tracking System ("GATS") that were approved by the NJ Clean Energy Office to produce Solar Renewable Energy Credits (SRECs). Monthly generation data in kWh was retrieved by energy year for all registered facilities. Importantly, generators that had not reported generation for all twelve months in the energy year were excluded from the solar performance calculations. For example, those solar facilities that came online partway through the energy year, and those facilities that had yet to report generation for the complete energy year were excluded. Failing to exclude generators that had only partially reported their annual production would result in understating system average performance. As a point of reference, for EY2018, 2079.4 MWs of solar capacity was included in the solar performance calculation for that energy year, representing 86% of all NJ solar capacity registered in GATS, and accounting for 94% of the EY2018 SRECs produced.

Solar energy production can be impacted by many variables, such as system size, tilt and orientation, fixed or tracking, shading, age, geographic location, and weather. Some of these variables are discussed in more detail in the report. Key findings of the analysis:

1. The average solar performance for all NJ systems and all five energy years analyzed was 1169 MWhs/MW of installed capacity.

2. Large systems (over 1 MW) produced better than smaller systems, averaging 1237 MWhs/MW over the five-year period.

3. Solar performance is directly correlated with solar irradiance (see orange bars in the chart below) and can be expected to vary from year to year. Over the five-year period of this analysis, overall solar performance (teal dashed line) ranged from a low of 1136 in EY2018 to a high of 1209 in EY2016. While solar irradiance data was not available for EY2018, it should be noted that EY2018 was unusually wet and might not be representative of typical/expected weather conditions.


Solar Performance (MWh/MW Installed)
Solar Performance
NJ Solar Irradiance (W/m²)
1300
1250
1200
1150
1100
1050
1000
950
148
146
144
142
140
138
136
134
EY2014
EY2015
EY2016
EY2017
EY2018
Over 1 MW
up to 1 MW
up to 100 kW
up to 10 kW
Total

Solar Performance Analysis

PJM EIS performed an analysis of solar performance for those facilities registered in the Generation Attribute Tracking System ("GATS") that were approved by the NJ Clean Energy Office to produce Solar Renewable Energy Credits (SRECs). Monthly generation data in kWh was retrieved by energy year for all registered facilities. Importantly, generators that had not reported generation for all twelve months in the energy year were excluded from the solar performance calculations. For example, those solar facilities that came online partway through the energy year, and those facilities that had yet to report generation for the complete energy year were excluded. Failing to exclude generators that had only partially reported their annual production would result in understating system average performance. As a point of reference, for EY2018, 2079.4 MWs of solar capacity was included in the solar performance calculation for that energy year, representing 86% of all NJ solar capacity registered in GATS, and accounting for 94% of the EY2018 SRECs produced.

Results of the solar performance analysis are shown below. The average solar performance for all NJ systems and all five energy years analyzed was **1169** MWhs/MW of installed capacity. Large systems (over 1 MW) produced better than smaller systems, averaging **1237** MWhs/MW over the five-year period.

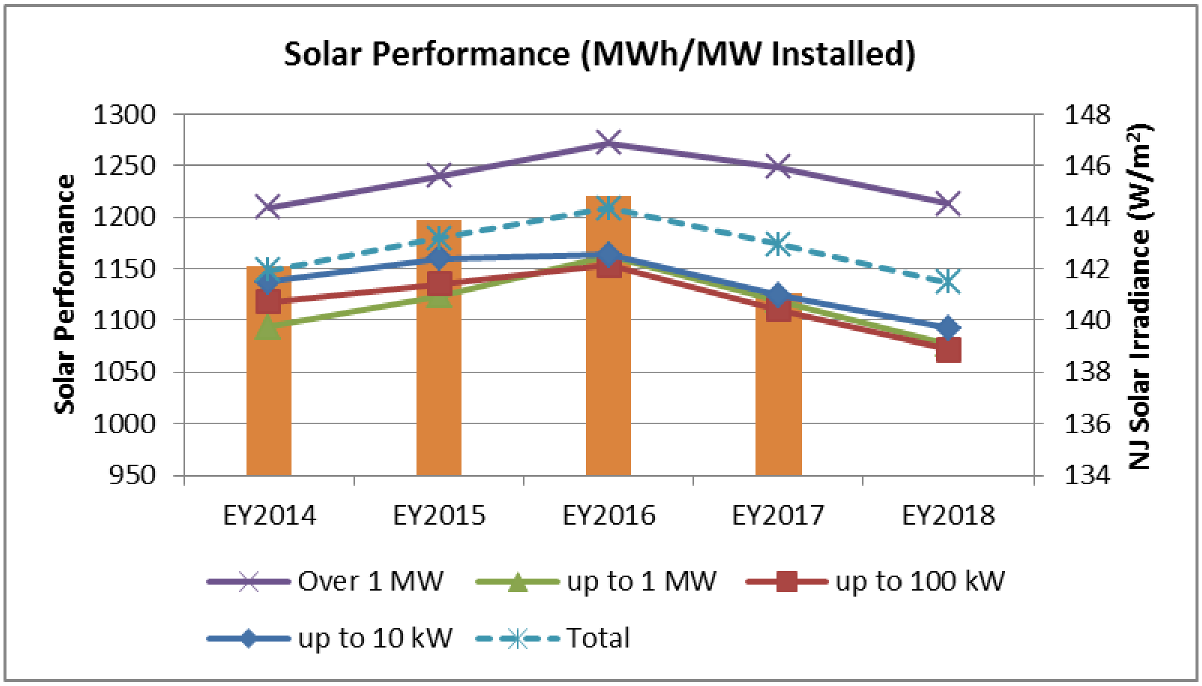
Capacity		Solar Performance (MWh/MW Installed)					
		EY2014	EY2015	EY2016	EY2017	EY2018	Average
up to 10 kW	MWh	112,764	149,327	201,228	283,544	372,456	
	MW Installed	99.1	128.8	172.9	252.2	340.9	
	Performance	1,138	1,160	1,164	1,124	1,093	1,136
up to 100 kW	MWh	128,592	153,265	191,062	246,539	317,172	
	MW Installed	115.0	135.0	165.6	222.0	296.0	
	Performance	1,118	1,135	1,154	1,111	1,072	1,118
up to 1 MW	MWh	462,112	501,921	577,943	586,492	601,241	
	MW Installed	422.4	446.7	496.9	524.2	558.3	
	Performance	1,094	1,124	1,163	1,119	1,077	1,115
Over 1 MW	MWh	551,148	691,448	796,822	914,641	1,072,347	
	MW Installed	455.8	557.7	626.4	732.4	884.3	
	Performance	1,209	1,240	1,272	1,249	1,213	1,237
Total	MWh	1,254,616	1,495,961	1,767,055	2,031,216	2,363,216	
	MW Installed	1,092.4	1,268.2	1,461.9	1,730.8	2,079.4	
	Performance	1,149	1,180	1,209	1,174	1,136	1,169

Solar energy production can be impacted by many variables, such as system size, tilt and orientation, fixed mount or tracking, shading, age, geographic location, and weather. Some of these parameters are known with certainty or can be easily estimated. For example, solar panel efficiency can be expected to degrade at a rate of approximately 0.8-1.0% per year.

However, solar performance is directly correlated with solar irradiance which varies year to year. The variability of solar irradiance over the five-year period of interest is discussed in more detail in the next section of this report. This variability makes it difficult to estimate precisely how much energy will be produced for any given year in the future. The New Jersey capacity-weighted average annual solar irradiance (W/m2) is summarized in the table below.

New Jersey Capacity-Weighted Average Annual Solar Irradiance (W/m^2)				
EY2014	EY2015	EY2016	EY2017	EY2018
142	144	145	141	n/a

The chart below plots annual average solar irradiance (orange bars) and solar performance. Over the five-year period of this analysis, overall solar performance (teal dashed line) ranged from a low of 1136 in EY2018 to a high of 1209 in EY2016. While solar irradiance data was not available for EY2018, it should be noted that EY2018 was an unusually wet year and might not be representative of typical weather conditions.



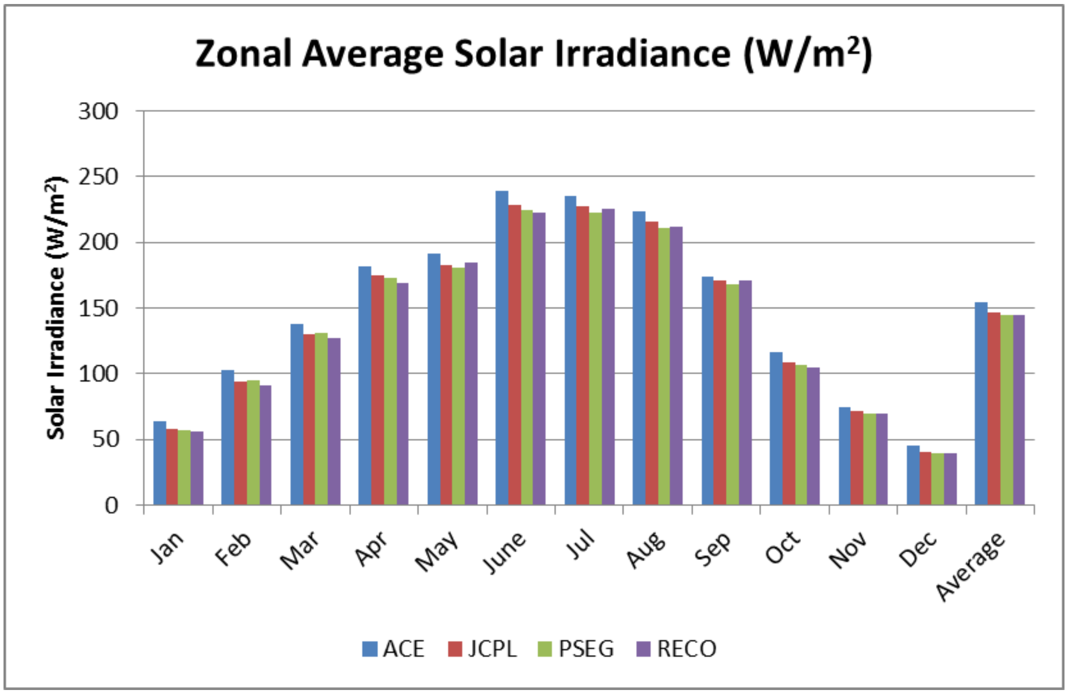
Historical Solar Resource Analysis

The largest factor influencing solar energy production is the solar irradiance, which can vary significantly. According to the National Renewable Energy Lab (NREL), in general, one can expect the system's total electrical output for a given *month* of a particular year to vary by as much as ±30% from the long-term typical value. Similarly, the total *annual* output for a particular year may vary from the long-term typical value by as much as ±10%.[1]

To better understand how New Jersey solar irradiance varies during the five-year period of interest, PJM EIS analyzed estimated solar irradiance data for June 2013 through August 2017, provided to PJM Interconnection by PJM's solar power forecasting service provider, AWS Truepower, a UL Company. The irradiance values are Global Horizontal Irradiance (GHI) values in Watts/m^2, and they are capacity-weighted average irradiance values by transmission zone, utilizing installed capacity registered in PJM EIS's Generation Attribute Tracking System (GATS) as of August 2017.

Solar Irradiance by Transmission Zone

In the figure below, one can see that the solar irradiance data varies by transmission zone, with the Atlantic City Electric (ACE) zone having the highest GHI on average. Solar facilities located in the ACE zone therefore would be expected to have greater energy production, everything else being equal.



[1] PVWatts Documentation, Results, available at https://pvwatts.nrel.gov/pvwatts.php

Solar Irradiance by Month and Year

The next figure confirms the NREL point that solar irradiance in a given month can vary by ±30%, and annual averages vary as well but to a lesser extent. It must be pointed out that estimated solar irradiance data was only available through August 2017. For the four Energy Years where all data was available, New Jersey solar irradiance was higher in EY2015 and EY2016, and lower in EY2014 and EY2017. 2018 was a particularly rainy year, so it is likely that solar irradiance for EY2018 was low as well.