Agenda Date: 12/06/19
Agenda Item: 8B

STATE OF NEW JERSEY

Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF A NEW JERSEY SOLAR TRANSITION PURSUANT TO P.L. 2018, C.17	))))	ORDER DOCKET NO. QO19010068

Parties of Record:

Stefanie A. Brand, Esq., Director, New Jersey Division of Rate Counsel

BY THE BOARD:

BACKGROUND

Solar RPS

The New Jersey Board of Public Utilities' ("Board" or "BPU") Renewable Portfolio Standards ("RPS") regulations, N.J.A.C. 14:8-2.1 et seq., implement provisions of the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. ("EDECA"). The RPS regulations require third party suppliers and basic generation service providers ("TPS/BGS providers"), as defined in N.J.A.C. 14:8-1.2, to include minimum percentages of qualified renewable energy in the electricity they sell. Those minimum percentages increase over time. The RPS rules specify separate minimum percentages for solar electric generation, for Class I renewable energy, and for Class II renewable energy, as each of these categories of renewable energy is defined by N.J.A.C. 14:8-1.2.

The Clean Energy Act of 2018, P.L. 2018, c. 17 ("Clean Energy Act" or "CEA") significantly increased the RPS requirements: it mandated that, by January 1, 2020, 21% of kilowatt-hours ("kWh") sold in the State be from Class I renewable energy sources. This requirement increases to 35% by January 1, 2025, and to 50% by January 1, 2030.

To comply with the solar electric generation portion of the RPS, TPS/BGS providers obtain and retire Solar Renewable Energy Certificates ("SRECs"). An SREC represents the environmental benefits or attributes of one megawatt-hour ("MWh") of solar electric generation. N.J.A.C. 14:8-2.2. A supplier or provider who holds too few SRECs to meet the RPS can make up for the shortfall by paying a Solar Alternative Compliance Payment ("SACP"). N.J.A.C. 14:8-2.3(e); N.J.A.C. 14:8-2.10.

Clean Energy Act

On May 23, 2018, the Clean Energy Act was signed into law and became effective immediately. Among many other mandates, the Clean Energy Act directed the Board to adopt rules and regulations to close the SREC Registration Program ("SREC Program" or "SRP") to new applications once the Board determines that 5.1 percent of the kilowatt-hours sold in the State by each TPS/BGS provider has been generated by solar electric power generators connected to the distribution system ("5.1 % Milestone"). The Clean Energy Act also directed the Board to complete a study that evaluates how to modify or replace the SREC program to encourage the continued efficient and orderly development of solar renewable energy generating sources throughout the State.

Additionally, the Clean Energy Act established a statutory cost cap that prohibits the cost of Class I RECs (excluding the cost of offshore wind renewable energy certificate, or "ORECs") from amounting to more than 9% of the total electricity paid by customers in the State during Energy Years ("EY") 2019, 2020, and 2021 and from amounting to more than 7% of that cost during subsequent energy years.

Closure of the SRP

On June 22, 2018, the Board proposed rule amendments to N.J.A.C. 14:8-2.4 to close the SRP to new applications following a determination by the Board that the 5.1% Milestone has been reached. These rules became effective upon publication in the New Jersey Register on January 22, 2019.

On August 7, 2019, the Board proposed further rule amendments to provide for an orderly and transparent mechanism for closing the existing SRP. These amendments set out the calculation methodology the Board will employ to determine that the 5.1% Milestone has been attained. Written comments were accepted through November 15, 2019.

Calculation of the 5.1% Milestone

In a February 27, 2019 Board Order,[1] Staff recommended that the Board calculate the 5.1% Milestone by dividing solar kilowatt-hours generated by total statewide retail kilowatt hours sold or the equivalent in megawatt-hours ("MWh"). In this February 27 Order, the Board noted that retail electricity sales for EY 2018 had declined to approximately 73.7 million MWh from more than 75 million MWh in the previous energy year. To produce 5.1% of 73.7 million MWh from solar generation, New Jersey would need approximately 3,132 MWdc of installed solar capacity operating for a full year.[2] However, the 5.1% Milestone will not be reached immediately upon the installation of 3,132 MWdc, but rather after additional capacity is installed and electricity is produced. At that time, based on the monthly reports generated by the SRP and on current estimates of installed capacity and consumption over a rolling twelve month period ending in the

[1] I/M/O the Modification of the Solar Renewable Portfolio Standard and Solar Alternative Compliance Payment Schedules and the Reduction of the Qualification Life for Solar Renewable Energy Certificates for Solar Facilities, BPU Docket No. QO18070698, Order dated February 27, 2019 ("February 27 Order").
[2] This figure is calculated by multiplying 73.7 million MWh by 5.1% and dividing the product by 1,200, the standard estimated kilowatt-hour production from one megawatt of installed capacity.

previous month, Staff anticipated that the 5.1% Milestone would be reached on or about June 2020.[3]

The August 7, 2019, pending rule proposal states that monthly estimates of the percentage of solar electricity within total retail kWh sold will be provided beginning 6 months prior to the estimated month of attainment of the 5.1% Milestone.[4] In compliance with the Clean Energy Act, the Board will terminate the SREC Program and close the SREC market to new entrants immediately following its determination that the 5.1% Milestone has been reached.

Modifying and Replacing the SRP

On November 5, 2018, the Board approved the engagement of Cadmus Group, LLC (collectively with their subcontractor, Sustainable Energy Advantage, the "Consulting Team" or "Consultant") to complete a study evaluating how to modify or replace the SREC program in a way that encourages the continued efficient and orderly development of solar renewable energy generating sources as required by the Act. Staff anticipates that the study will provide valuable insights into the incentive requirements for current and future solar electric generation facilities, including those in the SRP pipeline.

On December 26, 2018, Staff issued a Staff Straw Proposal and Request for Comments ("December Straw") which laid out seven "Transition Principles," further discussed below, and a proposed schedule for implementing the SREC Transition. The December Straw defined the Solar Transition as those steps necessary for: 1) the definition of the 5.1% Milestone and 2) the determination of incentive(s) developed to modify or replace the existing SREC program and the conditions for eligibility to said incentive(s). The December Straw proposed to organize the Solar Transition as follows:[5] 1) Legacy SRECs, available to projects eligible for the current SREC program; 2) the Transition Incentive, open to projects that filed a complete SRP registration after October 29, 2018 and have not yet reached commercial operation at the time the Board determines that the 5.1% Milestone has been attained; and 3) the Successor Program, open to projects that have not filed a complete SRP registration prior to the Board's determination that the 5.1% Milestone has been attained. Stakeholder feedback on the implementation of various elements of the Solar Transition was encouraged via a Request for Comments and two stakeholder meetings held on January 18, 2019 and February 22, 2019. Written comments were due by March 1, 2019.

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[3] The Board provides information on solar market activity to the public through the New Jersey Clean Energy Program website, NJcleanenergy.com. Staff's most recent projection finds that the 5.1% milestone could be reached as early as April 2020. The trailing twelve month total unadjusted BPU-jurisdictional load served through October 2019 was 74,741,115 MWh. This data was available to Staff within GATS as the statewide RPS administrator on November 6, 2019. The statewide load served by TPS/BGS providers must be adjusted for transmission and distribution losses to approximate retail sales subject to the RPS. With a 5% line loss factor applied, the estimate of retail sales for the trailing twelve months ending October 31, 2019 has fallen to 71,004,059 MWh. Staff reaches the April 2020 projection based upon the monthly cumulative installed capacity amounts updated November 20, 2019, an aggressive projection of new capacity joining the market at 45 MW per month on average though the next six months, and an application of the Board approved solar production protocol of 1200 MWh per installed MWdc.

[4] I/M/O of Amendments to N.J.A.C. 14:8-2.4 Renewable Portfolio Standard Rules on Closure of the SREC Registration Program Pursuant to P.L. 2018, c. 17, BPU Docket No. QX19060720, Order dated September 16, 2019 ("September 16 Order").

[5] The language in the December 26, 2018 Staff Straw was subsequently revised and clarified in the April 8, 2019 Staff Stakeholder Notice. The summary presented here reflects later clarifications (*e.g.*, the "Transition Incentive" was originally termed "pipeline projects").

The Board also clarified the SREC Qualification Life ("QL") in the February 27 Order,[6] stating that projects previously determined to be eligible for SRECs by meeting the October 29, 2018 deadline and satisfying all other applicable requirements shall continue to be eligible to create SRECs, with a 15-year SREC QL, after the State's attainment of the 5.1% Milestone. The Board further clarified that SREC eligibility for all applications submitted after October 29, 2018 is contingent upon commencing commercial operations prior to attainment of the 5.1% Milestone.

On April 8, 2019 ("April Notice"), in response to stakeholder input, the Board issued a Staff Stakeholder Notice which reiterated the seven "Transition Principles" and proposed the creation of a separate Transition Incentive, which would facilitate the transition between the Legacy SREC Program and the Successor program. The April Notice invited stakeholders to participate in two Stakeholder Workshops led by the Consulting Team, held on May 2, 2019 and June 14, 2019. At these workshops, the Consulting Team collected feedback on potential policy design for the Transition Incentive, and shared preliminary modeling assumptions and results for discussion with stakeholders. As further discussed below, those assumptions underlay a subsequent Consulting Team report and Staff Straw Proposal.

On July 10, 2019, the Board issued an Order[7] reiterating and clarifying that solar electric generation projects that have registered in the SRP after October 29, 2018, but have not commenced commercial operations at the time the Board determines that the 5.1% Milestone has been attained shall be considered for a Transition Incentive. Such consideration shall be subject to maintaining eligibility in the SRP in all respects and to the terms and conditions of the Transition Incentive. The July 10 Order further stated that a recommendation on the incentive structure, payment mechanics, and terms and conditions for the Transition Incentive program would be presented to the Board following development through the Solar Transition public stakeholder process.

On August 22, 2019, Staff issued a Straw Proposal regarding the 2019-2020 Transition Incentive ("Transition Incentive Straw" or "TI Straw"). As part of the TI Straw, Staff issued a report developed by the Consulting Team for the BPU entitled *New Jersey Transition Incentive Supporting Analysis & Recommendations* ("Consultant TI Report"), which informed Staff's development of the TI Straw. Appendices and supporting spreadsheets developed by the Consulting Team were also published on the New Jersey Clean Energy Program website.[8]

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

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

[6] In an October 29, 2018 Order, the Board had reduced the QL for solar facilities to 10 years for all applications submitted after October 29, 2018. I/M/O of the Modification of the Solar Renewable Portfolio Standard and Solar Alternative Compliance Payment Schedules and the Reduction of the Qualification Life for Solar Renewable Energy Certificates for Solar Facilities, BPU Docket No. QO18070698, Order dated October 29, 2018. Electricity must be generated during a facility's QL to be eligible for an SREC.
[7] I/M/O A New Jersey Solar Transition Pursuant to P.L. 2018, C.17, BPU Docket No. QO19010068, Order dated July 10, 2019 ("July 10 Order").
[8] Available at the following link: https://njcleanenergy.com/renewable-energy/program-updates-and-background-information/solar-proceedings.

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

In the TI Straw, Staff proposed the development of a Transition Incentive intended to be based on the creation and sale of Transition Renewable Energy Certificates ("TRECs") in conjunction with specific TREC Factors. The TREC Factors were intended to 'right-size' the value of a TREC to the specific incentive needs of specific types of distributed solar photovoltaic projects. The alternative approaches to valuing the proposed factorized TRECs presented by BPU Staff in the TI Straw include:

- A demand obligation without a Buyer of Last Resort in which prices are set entirely by supply and demand for TRECs;
- A demand obligation with a Buyer of Last Resort, which is assumed to be the electric distribution company in whose territory the project is located. The Buyer of Last Resort would purchase excess unsold TRECs at an agreed-upon fixed price at the end of the useful life of a TREC at the option of market participants; and
- A purchase program for TRECs at a fixed-payment rate.

The Consultant TI Report explored other potential policy mechanisms for valuing TRECs, but these were found to be either too expensive or impractical for purposes of the Transition Incentive and were not included in the TI Straw.

As noted above, the main assumptions that led to the incentive levels in the TI Straw had been shared with New Jersey solar stakeholders at the stakeholder workshops on May 2, 2019 and June 14, 2019. Following the concurrent release of the Second Staff Straw Proposal and the Consultant TI report, the BPU Staff offered several opportunities for public stakeholder comment, including:

- a webinar held August 23, 2019, to outline the TI Straw; and
- two public hearings, on August 28, 2019, and September 4, 2019, to allow stakeholders to provide comments on the TI Straw in person.

Staff also scheduled a follow-up stakeholder Technical Session with the Consulting Team on September 6, 2019. At the Technical Session, the Consulting Team again discussed the assumptions that informed the TI Straw, and New Jersey solar stakeholders had a further opportunity to raise issues and provide feedback on the assumptions.

As a result of the concerns raised, particularly those pertaining to the under-25 kW market segment, Staff and the Consulting Team examined potential adjustments to the market and policy input assumptions utilized. The results of these revised assumptions, combined with two programming corrections, were published by Staff alongside a revised Staff Straw Proposal ("October Revised TI Straw") on October 3, 2019. On October 11, 2019, another stakeholder meeting was held, with the Consulting Team present via webinar to answer questions. Written comments from stakeholders on the October Revised TI Straw were accepted through October 18, 2019 (extended from the deadline previously set for September 13, 2019).

November Revised TI Straw

On November 14, 2019, Staff issued an updated straw proposal, which included additional revisions to the Consulting Team's analysis ("November Revised TI Straw") and sought further public comment. The November Revised TI Straw reflected Staff's consideration of the Consulting Team's most recent modeling results, verbal comments made by stakeholders in public meetings, and written comments submitted to the Board by October 18, 2019. Written comments from stakeholders on the November Revised TI Straw were accepted through November 27, 2019.

A summary of the key options presented in the November Revised TI Straw follows:

The November Revised TI Straw proposed that projects eligible for the Transition Incentive would generate 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. Staff proposed that the creation of TRECs be based upon metered generation supplied to PJM-EIS General Attribute Tracking System ("GATS") by the owners of eligible facilities or their agents. GATS would create one TREC for each MWh of energy produced from a qualified facility.

Staff further proposed that the Board implement factorization for the TRECs. The TRECs would be designed to provide solar producers differing financial incentives tied to the estimated cost and revenue expectations for different types of solar facilities. Thus, the TREC would provide a higher incentive value to projects with the largest gap between project cost and revenue – in the terms of the program design, they would receive a factor of 1.0 (*i.e.*, the full incentive value of the base compensation set by the Board). Projects in segments where there is a smaller gap between costs and revenues would be assigned a percentage factor. The overall goal of factorization would be to ensure that ratepayers are providing the minimum necessary financial incentive to develop diverse types of projects consistent with maintaining a healthy solar industry in New Jersey.

The proposed factors were presented in the chart below (as presented in the November Revised TI Straw):

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

The Revised November TI Straw also identified two options for valuing each TREC, which would then be multiplied by the relevant factor to determine the subsidy level of each project. As described below, under Option One, the value would be set in a TREC trading market, comparable to the existing SREC market. Under Option Two, the value of each TREC would be set by Board Order.

Under Option One, 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. The compliance obligation may be more appropriately assigned to the TPS/BGS providers, who would procure and retire TRECs in proportion to their annual retail sales according to an annual schedule of demand obligations. This annual schedule would track the expected production of the projects eligible for the Transition Incentive, similar to the way in which the current compliance method for the SREC program operates. The value of a TREC would be limited by a Transition Incentive Alternative Compliance Payment ("TI-ACP").

Under Option Two, the value of each TREC would be a fixed price established by the Board ("TI Base Compensation"). Compliance may be facilitated by the EDCs, and ultimately assigned to the TPS/BGS providers in a competitively neutral manner. The EDCs would procure and retire all TRECs produced by eligible projects at the fixed price value assigned by Board Order.

Additionally, the Revised November TI Straw identified a potential valuation structure, based on a recommendation developed by the Consulting Team, by which the TI-ACP or Base Compensation schedule would be set lower for EY21, EY22, and EY23, then increase. This initial three-year kink period would lead to lower TREC prices in the early years of the program, and therefore to lower total Transition Incentive program costs during these three years. This would increase the probability that the total cost of Legacy and Transition incentives would remain compliant with the cost caps established by the Clean Energy Act. After EY23, the TI-ACP would increase to ensure that projects receive the full value of the incentive required to develop a project, as shown in the following chart developed by the Consulting Team. In other words, when the low kink period values are averaged with the higher post-kink values, the result would achieve a $152 average incentive (see Staff Recommendation 5: Value of a TREC).

The proposed TREC Base Compensation schedules, as presented in Revised Table 1 of the Revised November TI Straw, would be as follows:

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

Staff also proposed that TRECs be created in the year in which the underlying electricity is produced and have a useful life of 2 years. That is, a TREC owner would be able to sell a TREC to the TPS/BGS providers, EDCs, or TREC Administrator (as determined by the Board) in the Energy Year in which the electricity was produced or the following Energy Year. If the TREC is not produced or sold within two years of the electricity's generation, the electricity could form the basis of a NJ Class I REC. Solar electric generation facilities would be able to create TRECs for fifteen years following commencement of commercial operations ("TI Qualification Life", or "TI-QL"). Finally, the Revised November TI Straw presented two options for determining eligibility to receive TRECs.

Under Option One, projects that remain in the SRP pipeline at the time that the Board determines that NJ's retail electricity market has attained the 5.1% Milestone would be eligible for the Transition Incentive. Eligible projects would therefore be those that: 1) filed a complete SRP Registration, subsection (t), or subsection (r) application after October 29, 2018; and 2) have not commenced commercial operation upon the Board's determination that the 5.1% Milestone has been attained.

Under Option Two, the SRP would be closed to new registrants and a new Transition Incentive registration pipeline would be opened at a date certain, set by the Board to be prior to the anticipated date of the 5.1% Milestone. The Transition Incentive program would cover both the projects in the SRP pipeline that had yet to commence commercial operations and also any new projects registered in the Transition Incentive program at the time the 5.1% Milestone is attained. To enable this process, Staff proposed creating a new incentive registration and an associated pipeline, which would be merged with the projects left in the SRP pipeline at the time the 5.1% Milestone is attained. Staff noted that this option could give additional certainty to developers seeking to bring new projects online prior to decisions about the Successor Program. In addition, Option Two could potentially alleviate pressure from projects rushing to meet the 5.1% Milestone on both the existing SRP and on the Electric Distribution Companies' ("EDCs") interconnection infrastructure.

SUMMARY OF COMMENTS

A summary of the comments submitted, organized by major areas is set forth below. While the Board is summarizing the comments herein, the Board emphasizes that it has considered all comments in their entireties in reaching its decisions herein.

Prior to September 13, 2019, the following written comments were received: Asbury Park, Cy Yablonsky, E2/ECTA, Ila Gillenwater, Mayor Ravi Bhalla, Morris County Improvement Authority, ("MCIA"), New Jersey School Boards Association ("NJSBA"), Municipality of Princeton ("Princeton"), Richard T. Crouthamel, Rockland Electric Company ("RECO"), Solar Energy Industry Association ("SEIA"), Solar Industry Commenters,[9] Solar Landscape, Somerset County Improvement Authority ("SCIA"),[10] Township of Woodbridge ("Woodbridge"), and Trinity Solar.

Prior to October 18, 2019, the following written comments were received: Ad Energy, All Season Solar, Atlantic City Electric Company ("ACE"), Coalition for Community Solar Access ("CCSA"), Constellation, Delvar Solar, EZnergy Energy ("Eznergy"), Genrenew, Green Power Energy ("Green Power"), IGS Solar ("IGS"), Jay Panchal, Jersey Central Power & Light ("JCP&L"), Jim McAleer, Joseph Gaire, KDC Solar ("KDC"), Koppletric, Krannich Solar USA ("Krannich"), Kristin Dellanno, MCIA, Mid-Atlantic Solar & Storage Industries Association ("MSSIA"), NJSBA, New Jersey Conservation Foundation and Natural Resources Defense Council ("NJCF and NRDC"), New Jersey Division of Rate Counsel ("Rate Counsel"), New Jersey Resources Clean Energy Ventures ("NJRCEV"), New Jersey Solar Energy Coalition ("NJSEC"), Panatec Corporation ("Panatec"), Powell Energy and Solar ("Powell Energy"), Public Service Enterprise Group ("PSEG"), RCL Enterprises, RECO, Safari Energy, San Jay, SCIA, SEIA, Sierra Club, Solar Energy Systems ("SES"), Solar Landscape, SRECTrade, Inc. ("SREC Trade"), Sungage Financial ("Sungage"), Sunpower, Synnergy Saving Solutions ("Synnergy"), True Green Capital Management, LLC ("True Green Capital"), Vivint Solar, and Vote Solar.

[9] Larry Barth, Fred DeSanti, Thomas Lynch, Lyle Rawlings, and Scott Weiner
[10] The Morris County Improvement Authority, New Jersey School Boards Association, and Somerset County Improvement Authority filed joint comments.

Prior to November 27, 2019, the following written comments were received: Apollo Solar Partners, CCSA, CEP Renewables, LLC ("CEP"), Constellation, Genrenew, IGS, Marc S. Bellin, Esq. on behalf of his clients ("Mark Bellin"), MCIA, Mid-Atlantic Renewable Energy Coalition ("MAREC"), MSSIA, NJRCEV, New Jersey American Water ("NJAW"), NJSBA, NJSEC, RECO, SCIA, SEIA, SES, Solar Landscape, Solar Renewable Energy, LLC ("SRE"), , and Vivint Solar.

Staff received a total of 77 individual responses to requests for public comment to 3 Straw Proposals for Incentive Programs posted, respectively, on August 28, 2019, October 11, 2019, and November 14, 2019. Several stakeholders submitted comments on more than one Straw Proposal. In instances where stakeholders submitted multiple comments, all comments were summarized; however, if comments submitted by one commenter included conflicting positions, only the most recent position is reflected below.

The August TI Straw and October Revised TI Straw encouraged stakeholders to provide responses to 18 questions from Staff, organized by main topics. The November Revised TI Straw urged stakeholders to avoid reiterating comments made previously, and to focus on positions that may have changed in light of the November Revised TI Straw. A summary of the comments submitted, organized by the defined major topics, is set forth below. While the Board is summarizing the comments herein, the Board emphasizes that it has considered all comments in their entireties in reaching its decisions herein.

General Structure of the proposed Transition Incentive

Question 1
In question 1, Staff asked stakeholders to discuss the potential advantages and challenges of Staff's proposed Transition Incentive design.

Stakeholders generally supported the creation of a dedicated Transition Incentive, structured upon a TI-RPS. NJRCEV indicated support for the proposed management of the RPS during the transition process, with a preliminary RPS for the transition program to facilitate the BGS process and a subsequent RPS adjustment based on what project capacity is installed. SRE commended Staff's thinking on how to manage the RPS to support the transition program.

Some commenters expressed uncertainty regarding the transition from the SREC program: E2/ECTA stated that the SREC system should be preserved in some form for New Jersey to achieve its renewable energy goals; the commenter noted that systems installed by the utilities cost more than double those installed by non-utilities. Jay Panchel commented that SRECs should be maintained. True Green Capital wrote in support of comments submitted by NJRCEV, and emphasized the importance of ensuring a stable and balanced market for the legacy SREC program.

Vivint Solar commented that the Transition Incentive program should be as simple as possible given the circumstances so that more time can be used to develop the successor program. Vivint Solar further noted that making the SREC and TREC programs similar will simplify operations for developers, and recommended simply applying a factor to projects in the pipeline when the Legacy Program is closed, and then allowing them to function as legacy projects. Constellation stated that, regardless of how the Transition Incentive is set, the Board must move quickly to define and implement the SREC Successor program or risk the New Jersey SREC market becoming very complex and unwieldy.

Rate Counsel feared that both valuation options in Staff's Transition Incentive proposal treat the CEA's cost cap as a barrier to maximizing value for solar installations rather than as an indication of legislative intent to minimize costs to ratepayers. Rate Counsel noted that a recent report by PJM's independent market monitor showed that New Jersey payed roughly $606 million in 2017 RPS compliance costs, compared to an aggregate $809 million payed by all other PJM states.

PSEG, on the other hand, contended that pipeline projects should be eligible for the Legacy SREC program and that considering them separately from that program is inconsistent with the Clean Energy Act. PSEG read the CEA to require that all registered projects be eligible for SRECs, regardless of whether they have achieved commercial operation. PSEG proposed that the Board move straight to developing a successor program, based on the competitive procurement of SRECs and with established MW targets for annual auctions.[11]

Question 2
In question 2, Staff asked stakeholders to discuss the advantages and challenges of a fixed price TREC and a market-based TREC.

Several commenters supported a fixed price TREC, urging this approach as being simpler, more cost-efficient, and better able to facilitate financing than a market-based incentive. Rate Counsel recommended a fixed TREC with the compliance obligation on the EDCs for both legacy and transition projects. Rate Counsel asserted that the market-based approach would "fly in the face" of the CEA's objective of finding a more cost-effective mechanism than the existing SRP. Thus, although Rate Counsel expressed concern about the use of factors, Rate Counsel nevertheless recommended this approach as presenting a lower overall cost to ratepayers. Solar Landscape believed that a fixed TREC would provide crucial market stability and support, and CCSA stated it would obviate the need for on-going BPU market adjustments. SEIA supported the fixed price incentive structure for projects in the pipeline, with the compliance obligation placed on the EDCs, stating that the benefits of this approach included: 1) a lower incentive value than would be needed for a tradeable TREC; 2) more certainty for solar developers; and 3) avoiding implementation issues linked to creating a small tradeable commodity market. Solar Landscape and CCSA believed that a fixed TREC price would be better for community solar projects. Solar Landscape noted that the TREC market will be closed so that it will produce approximately the same number of TRECs regardless of the TREC price.[12] Sierra Club, Trinity Solar, Vote Solar, Solar Renewable Energy, NJRCEV, CEP Renewables, and Mark Bellin also supported a fixed price TREC.

MSSIA, Solar Landscape, CCSA, NJCF and NRDC, and NJRCEV all opposed the market-based approach due to its greater complexity and expense when compared to the fixed price scheme. In response to the buyer of last resort option with the tradeable TREC, MSSIA believed that, since the floor price would be paid only at the end of a TREC's trading life, the TREC would need to be 28% higher to maintain the same 8.5% rate of return as a fixed price TREC. Solar Landscape stated that the market-based approach would create a need for brokers, hedging markets, and financial engineering since solar developers and installers don't have those skills. NJCF and NRDC believed that the underlying reason to consider a market-based approach would be to facilitate TPS acquisition of the TRECs they would need for compliance, and the commenters do not believe that this justifies the additional complexity. The commenters identified above also stated that the market-based scheme would create too much risk; some were more concerned with price volatility and others with discounted TREC values as a result of uncertainty. Several of

[11] PSEG stated that this approach is used in NYSERDA's Renewable Energy Standard RFP model.
[12] The commenter uses the term "SREC" but appears to mean "TREC."

the above commenters noted that in a small, closed, and illiquid market, fluctuating price signals are not needed to guide development activity.

Several commenters opposed a fixed price TREC, and indicated a preference for a market-based TREC. NJSEC believed that a fixed-price TREC would likely be traded at a steep discount to reflect the risk that one or more of many external factors could change over a TREC's 15-year life. Constellation commented that a market-based approach would provide greater efficiency because supply and demand might produce a TREC price lower than the ACP. ACE and JCP&L supported a market-based approach, with ACE asserting that familiarity is an important consideration for a transition program of short duration, while JCP&L believed that competition will reduce the overall cost of the program while still ensuring that most projects in the transition program receive compensation through TRECs. RECO supported a competitive market for a number of reasons, including: 1) ease of implementation since the legacy SREC program is market based; 2) more transparency than a fixed price; 3) competition within the solar industry to continuously strive to provide products and services at a lower cost; and 4) easier the transition to the Successor SREC program, which RECO argued should be market based for these same reasons. RECO further stated that, if the Board were to choose a fixed-price TREC, the incentive value should be structured to allow projects to earn a reasonable rate of return, come in below the cost cap, and decline year-to-year to reflect declining costs of solar technology. Sungage also commented that it would be advantageous to retain a market-based approach over a fixed price because this approach has worked well in the past and builds in economic forces into the program to control costs.

<u>Question 3</u>
In question 3, Staff asked whether the proposed TREC would 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.

CCSA commented that the fixed TREC proposal provides the financial certainty needed for the community solar program, but that the market-based alternative would introduce an on-going administrative burden and uncertainty without providing proportionate benefits. Ad Energy stated that the kink period and potential market volatility limit financial surety. RECO commented that the continuation of a market-based approach would provide financial surety to projects currently in the SRP pipeline. NJSEC believed that the incentives as revised in the November Straw Proposal would be sufficient if and only if the kink years were eliminated from the model.

Some commenters provided suggestions as to how the BPU could improve market certainty. NJCF and NRDC believed there must be: a) a fixed TREC with no kink period; 2) project classes factorized on the basis of actual costs and revenues; and 3) the EDCs as the compliance entities, with cost recovery allocated over all customers. MSSIA believed that the needed adjustments to TREC factors are as discussed in the response to questions 13-15, where MSSIA advocates re-grouping the market segments and modifying the modelling so that a few sectors receive a lower factor than recommended in the Straw and most receive a higher factor. SEIA recommended that, if the BPU chooses a fixed price TREC, the Board's Order should confirm that incentive levels, once set, will not be revisited for the duration of the term of the Transition Incentive program, barring any changes in law, in order to provide certainty to the industry.

Rate Counsel believed that this question demonstrates the "misguided" orientation of the Transition Incentive proposal and states that the Board should not be trying to provide solar installations with financial surety.

Question 4

In question 4, Staff requested that stakeholders comment on how the Board can most accurately predict the amount of capacity expected to be in the SRP pipeline at the time the 5.1% Milestone is attained, and whether the Transition Incentive would require a true-up.

Rate Counsel stated that the forecast of capacity in the pipeline at the time of the 5.1% Milestone has been provided by the Consultants in their report and in Attachment 1 to the Straw Proposal. MSSIA stated that the size of the TREC program should be set several months before the 5.1% milestone is hit. If the amount of the pipeline that is actually built exceeds the size set for the program, MSSIA recommended a true-up; if the amount that is built falls short of the projected size, MSSIA proposed either a true-up or acceptance of additional projects. SEIA and Vivint Solar recommended that the size of the Transition Incentive pipeline be determined by the Board once the 5.1% Milestone is attained, and the obligation be set accordingly. PSEG concurred and specifically recommended that this obligation be applied to the LSEs in the next energy year after the first BGS auction that takes place post-5.1% Milestone.[13] PSEG opposed adjusting the obligation at any time, contending that this would contribute to volatility, increase costs, and conflict with the CEA's exemption of existing supply contracts. In the alternative, PSEG stated its willingness to discuss establishing "trading fungibility" between the Legacy, TREC, and successor markets. RECO, noting that the Cadmus model is not project-based, recommended using a model that includes known specific projects (based on project application) and a historical completion rate to yield a more accurate forecast of the expected time to meet the milestone. In RECO's opinion, a clear formula for how the 5.1% Milestone will be calculated must be developed before that milestone is reached.

A number of stakeholders provided comments on the calculation of the 5.1% Milestone. Green Power believed that there should be a true-up on final capacity for the current SREC program. To make the closure of the legacy program as accurate as possible, Green Power recommended NJCEP use the timestamp on each project's PTO notice from the EDC, and/or the timestamp of "As Built Submitted," to determine exactly which project caused achievement of the 5.1% milestone. NJSEC believed that if the kink year issue is not addressed by the Board and the Legislature (see question 9 below), a number of projects in the pipeline that will not achieve commercial operations before the 5.1% Milestone will be cancelled, throwing off the calculation of that milestone. MSSIA, as well as NJCF and NRDC, stated their belief that it will be very difficult to predict the amount of capacity entering the Transition Program until the incentive type and amounts are finally defined. NJCF and NRDC noted that there is still no specific proposal for the Successor Program, including how the risk of excessively low and high SREC prices will be addressed.

Several commenters emphasized the importance of transparency and disclosure regarding the calculation of the 5.1% Milestone. IGS urged Staff to publish reports on how close the market is to reaching the 5.1% Milestone in January 2020 rather than in March of 2020 because this information is critical to businesses' investment decisions. SEIA and Vivint Solar also urged the BPU to begin monthly reporting on the 5.1% Milestone in January. Solar Landscape expressed support for a high level of transparency and allowing sufficient lead time for project planning purposes.

[13] For example, if the Legacy program closes in September 2020; PSEG proposed that the demand obligation be imposed on the LSEs in the February 2021 BGS Auction and be reflected in supply commitments beginning in June 2021.

Eligibility

Question 5
In question 5, Staff asked how the Board should 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.

Question 6
In question 6, Staff asked whether the Board should cease accepting new registrations to the SREC Registration Program, and begin a new Transition Incentive pipeline.

Several market participants supported closing the SRP to additional projects in advance of attaining the 5.1% Milestone, as long as advance notice is provided. Solar Landscape believed that with such notice (*e.g.*, 90 days), short cycle residential projects could enter the pipeline without causing it to balloon as the 5.1% target approaches. Green Power believed that Transition Incentive registration should begin only once the Board has determined that the 5.1% milestone will occur in approximately two months, which Green Power believed is the minimum realistic time to move a project from SRP acceptance to PTO and As Built submission. MSSIA wanted notice for "projects that have already been awarded under the current program but have not yet had time to apply," by which MSSIA appears to mean notice for pipeline projects that have been accepted into the SRP but have not yet achieved commercial operation. Safari Energy also recommended that the Board immediately initiate a Transition Incentive registration pipeline. However, Safari Energy believed that the Board should also keep the SRP Registration open until the 5.1% Milestone is attained and not require new projects to enroll in the Transition Incentive. In its response to the November Revised Straw, NJRCEV revised its earlier response to say that opening the Transition Incentive registration early could be made more effective in mitigating oversupply risks in the legacy market if coupled with a program to encourage conversions of existing approved and operating projects into the transition program. NJRCEV proposed further discussing this suggestion with Staff and stakeholders. RECO cautioned that projects must have commenced commercial operations prior to the 5.1% Milestone in order to be eligible to receive SRECs. CCSA noted that, since it is unlikely that any of the selected community solar projects will achieve commercial operation prior to attainment of the 5.1% Milestone, all first year Community Solar projects should be automatically accepted into the Transition Program. Rate Counsel believed that the SREC Program should have been closed already because it costs too much and has kept prices high for far too long. The longer it remains open, in Rate Counsel's opinion, the larger the inflated price tag for ratepayers and the longer it will be paid. Rate Counsel asserted that projects in the pipeline that have not filed a complete registration or received approval and that have not commenced commercial operation at the time the Board determines that the 5.1% Milestone has been reached should be placed in the Successor Program.

Other commenters supported accepting new registrations to the SRP until the attainment of the 5.1% milestone, and therefore recommended that projects that are in the SRP pipeline (*i.e.*, have a complete SRP application) but do not achieve commercial operation by the 5.1% Milestone be eligible for the Transition Incentive (SEIA, Trinity Solar, Vivint Solar, NJSEC, Sierra Club, RECO, NJCF and NRDC). SEIA commented that projects that have filed a complete SRP application but are not yet operational should be eligible for TRECS upon hitting the 5.1%, and that ceasing to accept applications prior to reaching the 5.1% threshold is contrary to the language of the Clean Energy Act. Vivint Solar additionally commented that projects issued a PTO by the utility on or before the day that the 5.1% Milestone is attained should be allowed to complete their registration with the legacy SREC program, and not be moved into the Transition Incentive program. NJCF and NRDC expressed fears that a Transition Incentive that appears more attractive than the Legacy incentive could result in delaying attainment of the 5.1% threshold, which in turn could reduce the subsequent year's oversupply in the Legacy market, leading to higher Legacy SREC prices and a reduction in funding for the Successor Program. NJCF and NRDC therefore did not recommend that the Board cease accepting new registrations prior to the attainment of the 5.1% Milestone. NJSEC argued that the developers of most of the projects in the pipeline already know what their status will be at the time the 5.1% Milestone is anticipated to occur and that replacing the currently anticipated closure date and process would be severely damaging to those projects. RECO stated that eligibility for either the SREC or Transition Incentive programs would be based on a project's commencement of commercial operation prior to attainment of the 5.1 percent milestone, and therefore that no separate registration process for the Transition Incentive program would be required. PSEG went further and argued that all pipeline projects should be eligible for the Legacy SREC program, warning that if the Legacy program were too "constrained," high SREC prices could result that would impose undue costs on ratepayers and potentially threaten the success of the CEA.

SEIA also expressed concern about some projects that may be in "limbo" due to the unknown timing of the Transition Incentive program and the successor solar program. This could include projects delayed by interconnection studies, Board petitions, or other circumstances outside the control of the solar developer. SEIA and SunPower suggested that the Board take up program eligibility for these types of projects on a case-by-case basis, and cited the Massachusetts "good cause exemption" as a possible model. SunPower further urged the Board to incorporate as much responsible flexibility and discretion in their project eligibility criteria.

With respect to the future transition to the Successor Program, IGS Solar urged the Board to remain open to extending the Transition program in the event that the Successor program is not ready by the time the Board declares attainment of the 5.1% Milestone. Vivint commented that, provided that a successor program is ready for implementation, projects that do not have a complete SRP registration and have not commenced operation should qualify for the successor program and not the transition or legacy programs; projects that have a completed SRP but have not yet received operation should be eligible for the transition program.

Terms for each TREC

Question 7

In question 7, Staff asked stakeholders to discuss the proposed 15-year TREC term, with appropriate justification for any recommended changes.

Multiple commenters supported the proposed 15-year term, including SEIA, Solar Landscape, NJSEC, Sungage, SunPower, CCSA, MSSIA, Vivint, NJCF and NRDC. CCSA believed that in conjunction with a fixed TREC, the 15-year term provides a known revenue stream that will fit within program budget limits, although less beneficial in the market-based model. MSSIA stated that this term strikes a good balance between the lower annual ratepayer impact of a longer term, the lower Net Present Value rate impact and optimal investor confidence produced a shorter term, and the varying needs of good project economic performance. SunPower supported a 15-year term, and noted that a 20-year term could be a disadvantage to projects entering in 15-year agreements. Vivint noted that, though it generally prefers shorter terms, in the case of the TREC, and given the cost cap constraints, it believes that a 15-year term is appropriate.

Some commenters also expressed support for a 20-year term (CEP Renewables, NJCF and NRDC, NJRCEV, Mark Bellin, and Ad Energy). NJCF and NRDC noted their willingness to support a 20-year term as a means of reducing annual costs that is preferable to the kink period contemplated in the proposed Transition Incentive schedules, while NJRCEV noted that a previous Consultant analysis stated that a longer term could reduce costs. Mark Bellin and NJRCEV also thought that the longer term better matches the depreciable life of solar assets, and Ad Energy believed that it would better match the term of most financing products, thereby reducing cash flow risk for homeowners. SEIA noted that, while they recommend the use of a 15-year term, firms would not object to a 20-year term.

RECO commented that the TREC term should align with the current SREC term of 10 years.

Trinity Solar commented that a 10-year, 15-year, or 20-year TREC term would be acceptable, so long as the incentives were sufficient. SRE also supported either a 15-year or 20-year term.

Rate Counsel objected to the use of any qualification life as inconsistent with the Clean Energy Act and urged the Board to set an administratively determined schedule of fixed prices for both legacy and transition projects. In addition, Rate Counsel believed that the Board should clarify that once payments are accepted, the generators have transferred all rights to the solar attributes, as the Board determined in a 2005 matter involving REC ownership rights.[14] If some development such as a carbon tax creates additional economic benefits, Rate Counsel asserted that either appropriate compensation should be paid for the benefit of ratepayers or, alternatively, the fixed payments should cease.

Value of a TREC

Question 8
In question 8, Staff asked stakeholders to comment on whether the TI-ACP schedules proposed in Revised Table 1 were appropriate and what modifications to the schedules should be made.

Most stakeholders did not recommend any specific changes to the proposed ACPs. CCSA indicated that it did not recommend any changes to the proposed ACPs, and believed that the ACP is meaningful as a way to ensure the program does not exceed cost targets but will have no meaning in terms of transition incentives. Constellation requested that the values be published as soon as possible to allow suppliers to begin providing customers with greater price certainty and that these values not favor one solar technology over another, because a "level playing field" will ultimately lower costs for customers. NJSEC stated that the ACP levels need to be considered in conjunction with the factoring levels for each market segment to produce the minimum levels of incentives required in order to maintain the current level of employment.

MSSIA believed that the TI-ACP schedules shown in Table 1 of the Straw Proposal are generally appropriate, except as noted in MSSIA's concerns about the kink years (see comments summarized below) and provided that the factors were sufficient (see comments summarized below). NJCF and NRDC stated that they oppose a market-based approach and therefore stated that none of the ACP schedules shown in Table 1 of the Revised Straw Proposal would be appropriate. RECO commented that a market-based approach should consider a declining TI-

[14] I/M/O the Ownership of Renewable Energy Certificates ("RECs") under the Electric Discount and Energy Competition Act, as it pertains to Non-Utility Generators and the Board's Renewable Energy Portfolio Standards, BPU Dkt. No. EO04080897, Order dated April 20, 2005.

ACP, similar to the Solar ACP from the Clean Energy Act, while PSEG proposed a flat ACP without kink years or a post-kink increase. PSEG also recommended a lower ACP schedule, lower than the Legacy ACP, to reflect the lower project costs realized since the solar RPS was first set.

Rate Counsel opposed any ACP format given the historic cost of the SREC program and the fact that SREC prices have not decreased in response to the decrease in installation costs.

Question 9

In question 9, Staff asked stakeholders to discuss the idea of a "custom" TI-ACP, which would be relatively low in EY21, EY22 and EY23 ("kink period") and increase thereafter. This kink period design was initially developed in recognition of the statutory cost cap the program must operate under.

Numerous commenters strongly opposed the "custom" TI-ACP designed in response to the kink period because they believed it would impose extra financing costs, uncertainty, and forced up-front losses (SEIA, EZnergy, AD Energy, Joseph Gaire, NJCF and NRDC, Sungage, Trinity Solar, Solar Landscape, KDC, MSSIA, NJSEC, and Rate Counsel). Rate Counsel did not agree with the kink year structure because it sets low initial SACPs and then increases these values substantially and keeps them high. Rate Counsel noted that the Board has never before developed a set of SACP prices that increase rather than decrease and remain high. SEIA and PSEG recommended that the TREC values be levelized to provide a consistent value over the term of the incentive. SEIA further noted that setting lower TREC values during the kink period would be especially problematic if the TREC were designed as a tradable market. PSEG, which supports a tradeable market, noted the possibility of "uneconomic withholding" as a result of a sharply increasing ACP after the kink period. EZnergy and Joseph Gaire expressed strong concerns that the value during the kink years would be too low and would reduce demand for solar. NJCF and NRDC stated that incentive levels below the level of the revenues needed by projects in the kink years would imperil many transition projects. Ad Energy stated that the sharp drop in incentive levels would both depress demand for system purchases and harm consumers because many homeowners would receive a lower incentive than they expect and third party owned projects would face additional costs. Sungage and Trinity Solar expressed a concern the kink period would negatively impact the solar industry, in particular the residential market. Sungage further noted that it would push customers back towards third-party ownership models. Vivint Solar opposed the custom TI-ACP, stating that it would increase overall ratepayer costs for the program, be a challenge for financing and revenue models given the typical nature of current SREC monetization practices, and cause consumer protection concerns.

Other commenters indicated that designing a "custom" ACP to accommodate the kink period would likely hurt the ability of different project types to obtain financing. Solar Landscape noted that this would in particular be true for LMI projects such as those in Community Solar. KDC stated that the proposed incentive levels during the kink years would cut incentive levels by at least 60% and as such would make obtaining financing effectively impossible. MSSIA commented that the low kink year values would cause many projects to have negative cash flow during the first three years, necessitating an up-front cash reserve; this would deter investors. In addition, MSSIA believed that these low initial values would substantially raise the required incentive in the ensuing years and therefore significantly raise the overall ratepayer impact in Net Present Value terms. NJSEC believed that the proposed kink period ACP would severely distort investor expectations because undervaluing the first three years of eligibility in energy years 2021 through 2023 would create additional risk in the minds of investors and increase financing costs or even drive away investment entirely.

Sierra Club stated that it believed that the TI-ACP levels for projects during the kink years of 2021-2023 were low enough to be of some concern, but that this issue would be mitigated by allowing for a longer TREC eligibility period. RECO reiterated that the TI-ACP should decline in value similar to the current Solar ACP, and that the kink period proposal led to both the TI-ACP and the overall cost to ratepayers increasing in the later years.

With respect to the kink period "custom" ACP being a potential response to the cost cap, many stakeholders indicated that they believed that the "custom" TI-ACP was either not a response, or that there were alternative approaches possible to addressing the cost cap. MSSIA and Ad Energy believed that the kink period "custom" ACP would actually have only a very modest effect on the cost caps because the TREC program will be so small compared to either the Legacy Program or the Successor Program. Ad Energy further stated that the sharp drop in price might produce volatility, with some projects rushing to complete and others purposely slowing completion; therefore, Ad Energy believed that the kink period "custom" ACP would not guarantee avoiding a cost cap problem and removal of the kink would not guarantee that there will be one. MCIA, SCIA, and NJSBA stated that the cost caps will not cause any issue for program costs if the cost caps are calculated correctly. MSSIA believed that there are more effective and efficient ways to achieve compliance with the cost cap and recommends that those other measures be considered as alternatives to three years of low TREC values. As an alternative method of addressing the cost cap, Ad Energy recommended addressing legacy costs by creating a "tight collar" around legacy SREC values so that investors are protected from low SREC costs just as ratepayers are protected from high subsidy costs by the Clean Energy Act's cost caps. NJCF and NRDC also proposed developing a price "collar" for the legacy SREC market, effective upon closure. KDC suggested exploring other methods to deal with the statutory rate cap and the legacy SREC expenses from 2021-2013, such as "banking of cap delta in early years [and] averaging of solar costs over 3- or 5-year period." NJRCEV believed that there are numerous administrative procedures the BPU could employ to achieve compliance with the cost caps, including prioritizing in-state resources consistent with the direction in the Energy Master Plan during the kink period; banking and borrowing cap surpluses and deficits from year to year; and crediting value from solar against costs in a manner that recognizes the benefits of solar consistent with other state programs. NJRCEV recommended further engagement so that policymakers and stakeholders can find practical solutions. NJSEC suggested that the Board interpret the cost limit as a requirement to maintain at or below 7% as an average over a period of five or six years. Over the course of the past two energy years, according to NJSEC, the level of ratepayer contribution to New Jersey solar program has been about $480 million under the 9% cost limit. NJSEC proposes "banking" those figures and using them as an offset against the aggregate deficit of $320 million in the kink years, claiming that there would then be no need to treat incentive payments in energy years 2022, 2023, and 2024 any differently than the twelve years remaining in the years of eligibility. NJSEC asserted that this "banking" mechanism would be very similar to the 12-month "look back" that the Board used to establish an average value for the 5.1% market closure rulemaking. NJSEC advised that it has held discussions with legislative leadership and potential sponsors to amend the CEA such that the current caps are maintained. while the flexibility to "bank" is added to avoid the "cliff" that occurs if the cap is moved from 9% to 7% overnight. NJSEC believed that unless this proposed legislative alteration can be achieved in the lame duck legislative session, there will be job losses and significant project cancellations in the current pipeline. RCL Solar, SEIA, NJCF and NRDC also supported the idea of "banking" cost cap surplus. SEIA also believed that the Board should adopt a market balancing mechanism. NJCF and NRDC stated that that the simplest and most straightforward way to manage the RPS budget is likely to be using the surplus under the annual RPS cost caps in the first three years to pay for any deficits in the three kink years. NJCF and NRDC strongly supported both a price cap, lower than the statutory ACP, and a price floor, which might take the form of an EDC buy-back program, for the current SREC market. The commenters believed that a cap will be needed to ensure the RPS budget is not exceeded and to support full RPS compliance along with the creation of commercially attractive Transition and Successor Programs. They recommended that the Board focus on developing and deploying such a mechanism in the legacy SREC market, rather than on low prices for the kink years. SEIA further recommended that, given currently introduced legislation to clarify the cost cap's implementation, the Board should give itself flexibility in the Order creating a transition incentive to respond to new legislative direction without new rulemakings and further delay. Sierra Club suggested that, since incentives from funding sources other than the various RECs would not be subject to the cost cap in the Clean Energy Act, one option for could be to allocate revenues from the Societal Benefit Charge ("SBC") to offer one-time, temporary rebates on the purchase of solar systems; proceeds from RGGI auctions could also be used as a supplemental funding source, outside of the cost cap. Sierra Club also encouraged the Board to evaluate its authority to reduce other costs or barriers to solar investment, to reduce the level of incentive needed. With respect to the cost cap, RECO cautioned that incentives should not be inflated to include all the room available under the cost cap. Specifically, RECO noted that over-financing the SREC and Solar Transition and allocating the entirety of the cost cap to solar effectively eliminates the availability of funds within the cost cap for non-solar projects which is not in line with the draft Energy Master Plan's principle of providing technology-neutral policies, where appropriate. RECO recommended that, in order to minimize the cost impact to customers for the Class I RPS program, the "total paid for electricity" used to calculate the cost cap should be valued as the cost of electricity supply plus delivery charges reflected on customers' bills; additional surcharges, such as for Zero Emissions Certificates and Offshore Wind Renewable Energy Certificates, should not be included. Constellation urged Staff to implement an approach that will provide a formula for the cost cap calculation, define all components included in that calculation in advance of the term covered by each BGS Auction, and tie those components to data that is made publicly available. Constellation believed that this approach would enable LSEs to provide competitive pricing without factoring in additional regulatory risk. MAREC believed that the cost caps as currently calculated by Cadmus are contrary to sound and accepted economic analysis, and should include 1) the "merit order effect" whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers; 2) the savings directly provided to customers who install on-site renewable energy; and 3) the value of volatility hedge benefits.

Question 10

In question 10, Staff asked stakeholders to consider the implications of establishing a "Buyer of Last Resort" ("BLR") and floor price mechanism for the TREC market, and comment on the factors that Staff should consider in recommending how a purchase price is established.

CCSA supported establishing a BLR, stating that a BLR and floor price would be essential to the TREC market, to ensure renewable generation viability if the compliance obligation is set too low. Thus, CCSA believed that the BLR should have the obligation to purchase any TREC that is approaching the end of its viability and the floor price should be set at or above the fixed price proposed by BPU's Consultants. NJSEC believed that the mere fact of a floor price would do nothing to either shore up investor confidence or maintain current levels of employment. However, if established at or very near the minimum incentive levels that the industry requires to maintain current employment levels, NJSEC believed that this concept might represent a fixed cost option for LSE compliance.

Several commenters opposed establishing a BLR. JCP&L believed that the Clean Energy Act does not contemplate the EDCs purchasing TRECs, but if the EDCs are required to act as Buyers of Last Resort JCP&L believed that the Board should establish a market-based mechanism for TREC procurement; require the EDCs to purchase only a percentage of the TRECs approaching their expiration date; and set the maximum cost for a BLR purchase at a lower percentage of the clearing price for TRECs purchased for RPS compliance. JCP&L contended that this structure will encourage competition in the TREC market while still providing a backstop for most TRECs. RECO commented that guaranteeing a BLR and a floor price could undermine the function of a market-based approach in producing a solar incentive that reflects the actual market.

Finally, a number of commenters noted that a BLR would not be needed under certain TREC designs. Vivint Solar and Solar Landscape stated that they supported a fixed TREC, which would not require a floor price. Rate Counsel opposed a market-determined price in any form. Vivint Solar added that, if a market approach were to be selected, a buyer of last resort with a floor price mechanism would provide investors and financers certainty regarding the downside risk of the TRECs. Solar Landscape commented that, if the market approach were chosen, the Board should set a conservative/high price rather than an aggressive/low price because Solar Landscape believed that setting a high price will be simpler, more cost-efficient, and more likely to facilitate financing, as well as being better for community solar projects. Constellation did not favor the portion of the market-based proposal that would require the EDCs to act as buyers of last resort with a pre-established floor price, and believed that these features could be eliminated by increasing the TREC eligibility period to five years.

Question 11

In question 11, Staff asked stakeholders to comment on when and how a floor price should be established to provide the maximum benefit to ratepayers, developers, and investors.

Question 12

In question 12, Staff further asked stakeholders to consider whether the availability of a floor price above the NJ Class I ACP would provide any reduction in finance costs for eligible projects. Sierra Club and CCSA supported establishing a floor price in the case of a market-based TREC. CCSA asserted that, if a floor price were established, it should be set at or above the fixed price proposed by BPU's Consultants. CCSA further noted, however, that a TREC market would be expected to trade similarly to the current SREC market; the TI-ACP would be a cap on the market, but would not determine prices.

MSSIA and Solar Landscape opposed a floor price as costly and unnecessarily complex. If the floor price mechanism were adopted, MSSIA believed that it should be determined administratively and as soon as possible, so that developers can continue to develop the projects in the pipeline. MSSIA stated that it believed a floor price would reduce financing costs for solar compared to a market-based approach without a floor price, but would increase costs substantially when compared to the fixed-price approach. RECO opposed guaranteeing a floor price for developers and investors at the expense of customers. If a floor price were established, RECO suggested that additional stakeholder input including filing of public comment should be conducted to inform the price and provide for transparency. Rate Counsel opposed a market-determined price in any form.

NJSEC stated that no floor price would provide a reduction in finance costs unless it were set at or near the minimum value required to maintain the existing workforce. NJSEC further commented that, if a floor price at or very near the minimum incentive levels for maintaining current employment levels could be established, then that mechanism should commence promptly at the beginning of the transition.

<u>Factorization of TRECs</u>

<u>Question 13</u>
In question 13, Staff asked stakeholders whether they agreed with the proposed categories of factors.

Many commenters, including Solar Landscape, SEIA, Sierra Club, and RECO expressed support for the general concept of differentiating project incentives using factors, reflecting the fact that not all solar projects need the same amount of incentives. These commenters did, however, include general warnings regarding how these factors should be defined. Solar Landscape expressed fear that the program may prioritize further lowering cost at the risk of under-incentivizing young programs like community solar. RECO cautioned against over-incentivizing uneconomic projects and instead focus on those market segments that will meet state goals at least cost for customers. Sierra Club noted that the effectiveness of factorization would depend on the coupling of factors with TREC prices. NJCF and NRDC recommended that the BPU consider the best data and analyses offered by solar industry experts in setting its final categories and levels of factorization. NJRCEV believed that policy-driven factors used to guide future project development and cost reductions would be more appropriately considered in the successor program. Rate Counsel noted its general opposition to market segmentation mechanisms as representing an attempt to micromanage a set of solar submarkets that Rate Counsel believes the CEA intended the Board to eliminate. Moreover, Rate Counsel stated that without the opportunity to review the underlying work papers and calculations it cannot form a definitive position. Nonetheless, Rate Counsel preferred the fixed price approach to the market-based one and therefore accepts the factorization included in that approach.

Several stakeholders commented that the proposed categories of factors were unclear or insufficient (SEIA, CCSA, Solar Landscape, Solar Energy Systems). SEIA and Solar Landscape noted that there are common project types not clearly assigned to a group (*e.g.*, net metered and grid supply rooftop, parking canopy projects, rooftop community solar). CCSA asked that the Board provide more written guidelines regarding which SREC factor certain types of projects would receive. Specifically, CCSA believed that a community solar project that also qualifies as a preferred siting facility would qualify for the higher preferred siting TREC, but requested to see this in written guidelines. Vivint Solar stated that the factor categories are reasonable based on the major market segments, but that clarity will be required regarding special project types that may be eligible for two or more categories. PSEG asked about projects that have elements eligible for different factors, and recommended that the Board select the higher of two different factors in every case. PSEG also indicated uncertainty about the factor for net metered carport or rooftop projects above 25 kW.

Some commenters disagreed with the proposed categories as they were proposed in the TI Straw. MSSIA believed that the proposed categories group together different market segments with divergent needs, such that some project types are over-incentivized while some are under-incentivized. MSSIA believed that net metered roof projects should be grouped with community solar; net metered ground projects with grid supply projects; and net metered carports with landfill and brownfield projects. Green Power commented that residential rooftops should be considered "Preferred Siting." In support of its position, Green Power argued that residential rooftops are pre-existing, constitute an excellent solar resource, create and stabilize a "distributed-grid network", and are quickly permitted and installed.

Several commenters requested that the BPU create a specific factor for projects serving low- and moderate-income ("LMI") households (Vote Solar, Sierra Club, Apollo Solar Partners, Solar Landscape, Asbury Park, City of Hoboken, Township of Woodbridge, and the Municipality of Princeton). Solar Landscape recommended separate factorization values for a project's siting and for its offtake that would be multiplied to result in a final factorization rate for a project, citing the Massachusetts SMART program as a model. Solar Landscape believed that this approach would allow offtake types such as LMI community solar to receive additional incentives regardless of where a project is sited. Asbury Park, City of Hoboken, Township of Woodbridge, and the Municipality of Princeton recommended that LMI community solar projects receive a 1.2 factor due to fears that LMI ratepayers living in public housing with single utility master electricity meters on commercial tariffs will be disadvantaged because community solar bill credit calculation does not include demand charges in the credit calculation. PSEG recommended modifying the category of net metered projects under 25 kW to include all residential projects because it sees no reason to grant a higher factor and more valuable TREC to residential systems above 25 kW, of which it says there are 117 according to the July pipeline report.

NJRCEV and NJAW suggested that the emerging floating-solar category and in particular projects sited on off-stream raw reservoirs be included among the preferred siting incentives, reflecting the benefits of these projects to support large scale development without utilizing open-land. NJAW referenced a 2017 NJDEP report that notes floating-solar may become a preferred site as the technology matures and analogizes the two existing floating solar installations on New Jersey reservoirs to Storm Water Basins, which are already recognized as "preferred" siting.

SREC Trade commented on the implementation of factorization. SREC Trade stated that the TI Report contemplates a mechanism in which the NJ state certification number would determine the weight (or factor) of each REC produced by the system (*e.g.*, when 1 REC is retired from a residential system, it would only count as 0.5 for RPS purposes). SREC Trade believed that this method would cause confusion amongst all participants and result in RECs being transacted at inaccurate prices, and cited the case of the Delaware SREC market in which 20% Parts and Labor 20% is often not accounted for in the marketplace when RECs are transacted. SREC Trade offered the Massachusetts SREC factor model as an alternative solution, in which the factor is applied to the MWh by the registry (GATS in this case) prior to REC issuance (*e.g.*, 2 MWh would result in 1 actual RECs being issued, if the system had a 0.5 TREC factor).

Question 14

In question 14, Staff asked stakeholders to address the financial incentive levels for each of the four proposed factor categories.

Question 15

In question 15, Staff asked whether stakeholders agreed with the proposed assigned factors. The proposed financial incentive levels for the factor categories were revised in both the October Revised TI Straw and the November Revised TI Straw. Comments are therefore summarized below based on the version of the Straw that they are responding to, with greater detail provided to comments submitted in response to the November Revised TI Straw.

In response to the August TI Straw, NJ Clean Energy Solutions dba Solar Experts, Trinity Solar, PowerLutions LLC, MCIA, SCIA, and NJSBA objected to the proposed TREC factors, and in particular the factor proposed for the smaller than 25kW systems. Asbury Park, City of Hoboken, Township of Woodbridge, and the Municipality of Princeton recommended that LMI community solar projects receive a 1.2 factor. Solar Landscape recommended a factor of 1.0 for community solar projects.

In response to the October Revised TI Straw, there were criticisms that the proposed financial incentives were too low to support solar projects in the SREC pipeline. Many stakeholders stated that the Straw Proposal could harm the solar industry in New Jersey and that the Board should better align the TREC program with New Jersey's renewable energy goals. Kristin Dellanno, Joseph Gaire, and Powell Energy commented that the loss of the SREC incentive value would force employers to lay off workers and potentially close businesses. In particular, many stakeholders responding to the October Revised TI Straw opposed the proposed factor for small residential projects, asserting that a higher TREC was needed for this market segment. Koppletric, Greentech, AllSeason Solar, Krannich Solar, Synnergy, GenRenew, Jim McAleer, RCL Solar, IGS Solar, Green Power, SEIA, MSSIA, NJRCEV, NJSEC, Jay Panchal, San Jay, Sungage, EZnergy, Vivint Solar, Vote Solar, and Trinity Solar asked the Board to reconsider the proposed residential incentives, stating that the low incentive value proposed would severely harm the residential solar industry. RCL Solar noted the need for greater subsidies in the residential sector, where the cost to customers is greater than for commercial or non-profit projects. Nicole Roe of GenRenew commented that the residential developers need a TREC of at least $130, in part due to the fact that third party owners in the residential sector need to offer a savings at least 25% in order to be attractive to customers. Michael Mullen, co-founder of GenRenew, stated that, if the proposed incentive were to go into effect, his company will be forced to exit the residential NJ market and move all efforts into Illinois. Krannich Solar believed that the proposed program is both shortsighted and lopsided against residential solar, and stated that a TREC floor price of approximately $150 would be needed to avoid risking thousands of long-term jobs and losing millions of New Jersey state revenues. Jim McAleer commented that if the transition were to proceed as proposed, his company would go out of business due to the reduction of the Federal tax credit in 2020 and 2021; the low TREC values in the kink years; and the long-term values of the TRECs. Synnergy stated that the $38 rescue level for unpurchased SRECs would be a clear windfall being set up for the benefit of the Utilities. SEIA recommended that the factor for residential projects be increased to 0.7. Sungage noted that the proposed incentive was an improvement to the initial TI Straw, but remained insufficient to maintain the same level of residential development. Green Power stated that the factor for net metered projects is too low to be viable, and that residential rooftops should receive a 1.0 "preferred siting" factor. Green Power further argued that the Board should let the market determine the economic viability of a project and should not sanction the above disparity in the incentive level across the categories of factors. MSSIA calculated that net-metered systems require factors between 0.89 and 1.08 depending on the size and type of system. NJRCEV calculated that residential and small commercial systems would require an incentive of $125/MWh (as opposed to $69 in the October Revised TI Straw). Vivint Solar stated that the average TREC value for residential projects needs to be between $110-$125/TREC. Rate Counsel opposed the increased factor for net metered systems,[15] which it finds significant in combination with the increased base price.

[15] Rate Counsel made this comment on the Revised Straw's increased factor from 0.2 to 0.5 and can be assumed to oppose still more the November Revised Straw's increased factor from 0.5 to 0.6.

Stakeholders also submitted comments on the proposed incentive levels for the other factor categories. Synnergy proposed that the existing levels of SRECs be maintained for municipal facilities and particularly school boards or, at minimum, that all taxing authorities (*e.g.*, municipalities, school board) be classified as preferred sites. SEIA recommended that the factor for ground mounted and grid supply projects be increased to 0.75. SEIA and CCSA supported the proposed 0.85 factor for community solar projects. Solar Landscape, MCIA, SCIA, and NJSBA commented that community solar projects should receive a factorization rate of 1.0. Delval Solar urged the Board to re-categorize the Agri-Voltaic systems into Tier One rather than Tier Three, because these systems use the same square footage as the agriculture they are located over and therefore should be categorized as Tier One like systems located on rooftops and carports. IGS Solar expressed concern with the significant difference in incentive proposed for ground-mount vs. rooftop net metered systems over 25kW; IGS Solar proposed that all net-metered systems over 25kW receive a fixed 15-year incentive of $120/MWh. MSSIA calculated that subsection (t) projects would require a factor of 1.13; grid supply projects would require a factor of 0.87; and community solar projects would require a factor of 0.9 or 0.91 (depending on the site). NJRCEV calculated that large commercial ground-mounted projects need a TREC of $125 (vs. $70 in the October Revised TI Straw), and that ground-mounted grid-supply projects need a TREC of $145 (vs. $75 in the October Revised TI Straw). NJSEC found the factors for large commercial net metered ground-mounted projects to be low by about 35%. KDC said that its own analysis, based on actual costs of recently constructed projects and quotes on development projects, shows that the proposed TREC for C&I ground mount is only 85% of the level need to achieve an unlevered AT IRR of 8.5%. The proposed C&I carport TREC, according to KDC, is only 55% of the incentive required to achieve the same IRR target.

Sierra Club commented that the October Revised TI Straw included improved factors for net-metered systems under 25 MW projects as compared to the original TI Straw. Sierra Club noted that it is appropriate to give higher levels of incentives to community solar, and solar projects on preferred sites such as brownfields, parking lots, and landfills. Ad Energy recommended that any factorization introduced should be close to 'one' for all segments, which it stated can be done by reducing the baseline TREC price so that the total TREC cost remains unchanged. RECO urged the Board to calculate the factors that provide the lowest cost to ratepayers.

In response to the November Revised TI Straw, several stakeholders commented that the revised proposed incentive levels remained challenging, but feasible. SEIA believed the incentive levels were now viable for most distributed market segments and based on the values proposed, a considerable number of projects in the pipeline would be expected to move forward. NJSEC commented that the incentive levels resulting from the proposed factors in the November Revised Straw would be very challenging but feasible, as long as the kink period issue is addressed. NJSEC noted that the proposed incentives would reduce the cost of the current program by about 50%, as measured by the current spot market. Others, including NJRCEV, SRE, Apollo Solar Partners, and GenRenew commented that the proposed factored incentive levels remain below what is needed to sustain certain market segments. MSSIA commented that it has modeled nine project types according to the assigned factors in the straw proposal, using an investor model that it says is used in actual investor decision-making and in setting prices for competitive bids.[16] MSSIA stated that their analysis found that the proposed factor values over-incentivize some market segments, while under-incentivizing others. Apollo Solar Partners commented that, in general, TREC values need to be higher, because at least 85% of solar projects rely on the ITC

[16] MSSIA attached a comprehensive table of all the assumptions used in its modeling as an appendix to its comments.

for financing and the ITC is diminishing and will soon be gone. Apollo Solar Partners also asserted that tariffs have increased overall project pricing by over 15 percent.

With respect to the November Revised TI Straw proposed incentive level for small residential net metered projects, IGS Solar and SEIA stated that a 0.6 TREC factor for net metered systems under 25kW in the November Revised Straw represents a workable path forward for this market segment. Solar Landscape commented that, if roof-mounted net metering projects receive a factor of 0.6, this would put them at a disadvantage relative to ground-mounts, despite being a preferred site. MSSIA's calculations indicated that small residential net metered projects require a factor of 0.89. SRE commented that the incentives proposed for residential remain below the levels necessary to attract and sustain investment. NJRCEV commented that residential net metered projects need an incentive of $125/MWh, and GenRenew requested a TREC value of at least $130. Despite concerns about methodology, Vivint Solar commented that the November Revised TI Straw proposed value for the <25kW market segment was much closer to what is needed to allow most projects to remain economically viable.

With respect to the November Revised TI Straw proposed incentive level for ground-mounted C&I projects, IGS Solar asserted that the move to a 0.6 TREC factor would not be not sufficient and reiterated its support for a fixed $120 TREC for fifteen years, which it calculated would correspond to a 0.75 TREC factor for this market segment. MSSIA's calculations indicated that larger ground-mounted net metered projects would require a factor of 0.85; larger roof-mounted net metered projects would require a factor of 0.89 or 0.9; net metered carports would require a factor of 1.08; subsection (t) projects would require a factor of 1.13; and grid-supply projects would require a factor of 0.87. SEIA recommended increasing the factor for grid-supply projects to an average of $122/MWh over 15-years, or a factor of 0.75. NJRCEV believed that the 1.0 factor for the preferred siting category is sufficient. SRE and NJRCEV commented that large commercial ground-mounted projects need a TREC of $125, and ground-mounted grid supply projects need a TREC of $145.

With respect to the November Revised TI Straw proposed incentive level for community solar projects, SEIA indicated that the 0.85 factor should be sufficient to support new project development. NJRCEV stated that the November Revised Straw's proposed incentives are sufficient to support large scale community solar sites on landfills with a 50/50 mix of commercial and residential tenants. However, NJRCEV believed that the TREC values are not high enough to encourage a diverse mix of community solar configurations such as smaller rooftop projects, carports or master-metered projects in the commercial rate class. Solar Landscape expressed concerns that all community solar projects (roof-mounted and ground-mounted) appeared to receive the same factor of 0.85, which would not provide additional incentive to the preferred roof-mounted site. MSSIA's calculations indicated that community solar projects would require a TREC value of 0.9 or 0.91, depending on the site and project size.

Apollo Solar Partners further commented that LMI projects should receive the highest TREC values.

In response to each of the TI Straws, many commenters expressed strong disagreement with specific modeling assumptions used by the Consulting Team to calculate proposed incentive values and factors (NJCF, NRDC, NJRCEV, NJSEC, MSSIA, SRE, Vivint Solar, SunPower, Trinity Solar, and KDC). Stakeholders stated that TREC factors must be consistent with the actual costs and revenue shortfalls of pipeline projects in each category, and that changes to the Consulting Team's models and the proposals need to be made. Specifically, stakeholders disagreed with the Consultant's approach to modeling incentives based on the 50th percentile of survey and self-reported data on installed costs, stating that this approach does not recognize the reasons for which costs will vary from project to project. KDC stated that this assumption will limit the number of pipeline projects actually installed, and is likely to cause commercial and carport projects to be abandoned. NJSEC claimed that the 50th percentile of costs does not accurately represent development costs going forward, as the "low-hanging fruits" have all been built. Several stakeholders also expressed concerns that about the use of PSE&G retail rates as a modeling assumption. Stakeholders believed that projects should be modeled at 26 percent ITC, not 30 percent, because the small projects cannot efficiently safe harbor costs due to their lack of economies of scale while the larger projects have likely missed their window to safe harbor, as well due to the uncertainties around the transitional program and the December 31, 2019 deadline.

In regards to solar production estimates, NJRCEV, MSSIA, NJSEC, Trinity Solar, GenRenew, and MCIA, SCIA, and NJSBA urged the use of actual historical production data rather than PV Watts estimates. NJRCEV stated that the Consulting Team's assumptions overstated solar production by 10 to 15 percent on average. Stakeholders also found the Consultant's assumption that solar electricity can be priced at a 15 percent discount to retail rates with a 2 percent escalator, stating that a 15 percent discount rate to be problematic: they stated that the price escalator is higher than what is actually experienced, and several stakeholders stated that a discount rate of 25% would have been more appropriate. Based on its own experience, NJRCEV stated that customers require discounts of at least 25 percent of retail rates to adopt solar. NJRCEV asserted that discounts of 50-60 percent are more the norm in this market and that if the Consultant reran its model assuming a 50 percent discount to average New Jersey commercial rates, the resulting TREC value should be equivalent to the $125/MWh NJRCEV proposes. NJRCEV also opposed using net metering benefits to reduce incentives for either residential or community solar customers. In NJRCEV's opinion, a comprehensive discussion of net metering, value of solar and possible net metering successors is well beyond the scope of the transition program and should not influence the proposed incentives. NJCEV believed that the Consulting Team modeling assumptions on lease and energy rates for solar are too high, resulting in TREC values below levels necessary to support new project development. As to the commercial net-metered sector, NJRCEV believes that the installation cost assumptions used by the Consultants are about 20-30 percent below realistic levels, based on its own experience. MCIA, SCIA, and NJSBA questioned the lack of clarity as to whether the Consultant accounted for on-peak and off-peak accounting used by utilities to calculate net metering volumes. MCIA, SCIA, and NJSBA stated that the wholesale energy forecasts were overestimated. MSSIA questioned whether the Consultant included development costs or fees. MSSIA further stated that the Consultant should have used a target unlevered, after-tax IRR of 8.5%, which MSSIA states is considered to be the approximate minimum that can be financed. MCIA, SCIA, and NJSBA stated that the Consultant's analysis was not transparent as to how project inputs resulted in market design and multiplier outcomes; they stated that the modeling and adjustments conducted by the Consulting Team were not provided for stakeholder review.

Rate Counsel was generally skeptical of the use of factors and opposed any increases to them.

Compliance Entities

Question 16

In question 16, Staff asked stakeholders to discuss the advantages and disadvantages of the two proposed options, *i.e.*, having the compliance entities be: 1) TPSs and BGS providers, or 2) the EDCs.

Question 17
In question 17, Staff asked which of the two options stakeholders preferred.

Question 18
Finally, in question 18, Staff asked stakeholders whether they agreed 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.

Some stakeholders and all of the EDCs supported Option 1, *i.e.*, setting the compliance obligation on the TPS and BGS providers, in light of the fact that it would be a continuation of the current mechanism for SREC compliance. ACE and PSEG supported requiring TPS and BGS providers to procure and retire TRECs because the transition period is expected to be of limited duration and this approach would leverage the existing processes for SREC compliance in New Jersey. JCP&L commented that the EDCs already have procedures in place to receive and report on RPS compliance obligations from their BGS providers, and that keeping current processes in place to the maximum extent possible will promote an orderly and transparent mechanism for the closing of the existing SREC program. JCP&L further noted that N.J.S.A. 48:3-87(d) dictates that LSEs be the Compliance Entities for the procurement of RPS obligations. JCP&L bases this assertion on the statute's referencing only BGS providers and electric power suppliers when granting the Board authority to establish a schedule requiring that a "number or percentage . . . of kilowatt-hours sold in [New Jersey] . . . to be from solar electric power generators connected to the distribution system in [New Jersey]." Id. JCP&L states that there are no comparable directives for the EDCs, and therefore that the Clean Energy Act does not contemplate the EDCs purchasing TRECs. RECO recommended that the compliance obligation remain with TPS and BGS providers, maintaining consistency with the Legacy SREC Program and the Class I REC program. RECO believed that assigning the TPS/BGS providers as the compliance entities aligns the supply side cost of compliance with the suppliers. RECO and PSEG added that requiring EDCs to be the sole compliance entities would result in increased administrative costs for the EDCs; RECO also stated that it would be inconsistent with current RPS obligation requirements that remain with third party suppliers and BGS providers. RECO did note that the advantage of having the EDCs serve as the compliance entities is transparency in equitable distribution of costs to all customers due to the small number of EDCs; however, RECO stated that having the EDCs facilitate a supply cost is not a reasonable long-term solution and should be reconsidered for the Successor Program. NJSEC also supported maintaining the current system, at minimum for the transition incentive period, as it is familiar. NJSEC opposed making EDCs the compliance entity because the administrative costs are unknown at this time and these costs would need to be recovered from the ratepayers. As an alternative to the two options proposed in the TI Straws, NJSEC suggested that the Board set the Transition Program compliance obligation at an overall level that would ensure that the market would be a perpetually short market for the full 15-year compliance period; TRECs would then be traded between generators and LSEs at a small discount to the ACP until all generated TRECs were sold in the market. According to NJSEC, LSEs would pay the ACP to the state to satisfy the remaining balance of the "short market" compliance obligation; the state could then use these residual funds to purchase Class I RECs in an auction or refund these unused funds to ratepayers. NJSEC acknowledges that its proposed process will would likely create TREC discounts between generators and LSEs in the range of 2%-5% of the $189 value, which would further tighten project financial modeling. Constellation supported a market-based approach to valuing TRECs with TPS/BGS providers serving as compliance entities.

Other commenters supported Option 2, *i.e.*, having the compliance obligation be facilitated by the EDCs. Solar Landscape, NJCF and NRDC indicated that having the EDCs as the compliance entity would be the easiest, quickest, and most efficient option. Solar Landscape added that it would provide a more transparent method for passing costs onto ratepayers, and would be a more predictable way to set a Compliance Obligation than using a percentage of energy sales of TPS or BGS providers. CCSA and Ad Energy supported Option 2 in light of their preference for a fixed TREC and for all TRECs to be purchased. SRE agreed that a fixed price TREC with EDCs as the buyer of TRECs is a viable structure.

JCP&L commented that if the Board does require the EDCs to serve as the Compliance Entities for the procurement of TRECs, the Board should establish cost recovery mechanisms such that there is no net financial impact on the EDCs. JCP&L reasons that the projected annual supply of TRECs should be predictable based on the progress of projects in the TREC program, which JCP&L believed would lend itself to contemporaneous recovery of TREC program costs. JCP&L also pointed to the fact that the EDCs' current BGS costs have historically been recovered on a more contemporaneous basis compared to other costs.

Rate Counsel recommended a fixed TREC with the compliance obligation on the EDCs for both legacy and transition projects.

Ad Energy and SEIA agreed with the statement 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.

Trinity Solar, MSSIA, NJCF, and NRDC disagreed with the statement that a market-based approach would foster the use of the TPS/BGS providers, rather than EDCs, as compliance entities. NJCF and NRDC believed that the TPS/BGS provider alternative, with an EDC buyback price floor, would likely require a significantly more complicated tariff and entail more delays. Trinity Solar and MSSIA stated that TPS/BGS provider compliance should be able to work under a fixed price scenario.

Sierra Club suggested that the BPU consider setting minimum demand obligations for each factor type, as opposed to a single demand obligation for all TRECs in a given year.

MSSIA expressed that either EDCs or TPS/BGS providers could be appropriate in the role of compliance entity for a fixed TREC. MSSIA stated that EDCs have some advantages, since they are well-positioned to collect funds through a charge to ratepayers and pay the TRECs to system owners, and using them as compliance entities would tend to make the program relatively easy to track, monitor, and control. However, MSSIA also noted that TPS/BGS providers are the current compliance entities for SRECs, and that using these entities would minimize change and avoid the need to set up a special charge on ratepayer bills. MSSIA expressed some reservations regarding how to ensure market neutrality if the TPS/BGS providers option is selected by the Board.

<u>Other</u>

Rate Counsel stated as a general criticism that too brief a period was provided to prepare comments and that several different sets of values appear to have been provided for the fixed TREC after the kink period without an indication of which was recommended. Rate Counsel thus reserved its right to argue that the Board did not provide sufficient notice and opportunity to comment.

STAFF RECOMMENDATIONS

In developing a recommendation on the creation and design of a Transition Incentive, Staff has been mindful of the seven general principles announced at the outset of the process that have guided the SREC Transition process. Of particular relevance to the development of a Transition Incentive were the following six principles:

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 to 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; and
6. Comply fully with the statute, including the implications of the cost cap.

A brief description of these criteria as they relate to Staff's evaluation of the Transition Incentive follows:

1. Provide maximum benefit to ratepayers at the lowest cost:

The incentives available to support solar energy are funded by New Jersey electricity ratepayers. As such, prudence requires that these funds be used as efficiently as is practicable. The proposed Transition Incentive should therefore aim to ensure that the cost of the incentive is close to the minimum needed. An incentive structure that reduces regulatory uncertainty to the extent reasonable and prudent also lowers costs and helps to protect the ratepayers' interests.

2. Support the continued growth of the solar industry:

The RPS and the SRP have operated to develop a robust and sustainable market for renewable energy in New Jersey. The 2019/2020 Solar Transition process as a whole aims to ensure that New Jersey's solar industry continues to thrive, while adapting to changing market conditions. The Transition Incentive would provide a bridge between the Legacy SREC Program and the Successor Program.

3. Ensure that prior investments retain value:

A robust and sustainable market depends on an economic environment that supports investor confidence. Safeguarding investments previously made is therefore an essential part of supporting sustained, orderly market development.

4. Meet the Governor's commitment to 50% Class I Renewable Energy Certificates ("RECs") by 2030 and 100% clean energy by 2050:

Solar electric generation and other sources of renewable energy support the State's efforts to reduce emissions of greenhouse gases and other air pollutants associated with electric power generation. In general, program design can support increased adoption of renewable energy resources by a wide variety of types of customers.

5. Provide insight and information to stakeholders through a transparent process for developing the Solar Transition and Successor Program:

As described in the Background section of this Order, Staff has engaged extensively with stakeholders on the development of the proposed Transition Incentive.

6. Comply fully with the statute, including the implications of the cost cap:

As discussed above, it is important that ratepayer funds be used prudently and efficiently. The Clean Energy Act codifies this priority by setting a cost cap on the expenditures that may be made to incentivize renewable energy: no more than 9% of total electricity payments in the State for EY 2019 through 2021, and no more than 7% of the total paid subsequent energy years. In compliance with this mandate, the models proposed by Staff and the Consultant for stakeholder input were designed to comply with the cost cap.

Finally, Staff notes that it has fully considered the modeling results and sensitivities developed by the Consultant, the experiential data and recommendations contained in the various comments received to date, its own internal analyses, and the importance of the solar industry to the State of New Jersey. Staff carefully weighed each of these considerations and did not rely on any one set of findings, but instead attempted to balance the various competing arguments. While Staff considered the modeling results provided by the Consultant, Staff does not consider the Consultant's findings binding and did not rely solely on those findings. After taking each of these into account, Staff recommends the following:

Recommendation 1: Creation of a Transition Incentive

Staff recommends that the Board establish a distinct Transition Incentive ("TI") to provide a bridge between the Legacy SREC program and a to-be-determined Successor Incentive Program. Staff's recommendation for creating a dedicated TI is driven primarily by recognition of the rapid timeframe mandated by the Clean Energy Act and a desire to minimize the associated market uncertainty. The CEA mandates that the SREC program be closed to new registrations once the Board determines that the 5.1% Milestone has been attained. At present, Staff estimates that this could occur as early as April 2020. Stakeholders have conveyed that the closing and replacement of the SREC Program has caused significant regulatory uncertainty within the solar market. In particular, Stakeholders have expressed concern for projects currently in the SREC pipeline, projects that may have existing contracts in place but are not certain of achieving commercial operation prior to the attainment of the 5.1% Milestone.

To ensure a smooth transition from the Legacy Program, therefore, Staff believes that it is appropriate to develop a targeted Transition Incentive for those pipeline projects. The Transition Incentive would remain open until the adoption of a Successor Program, intended to provide a mechanism for solar incentives for the longer term. The establishment of a Transition Incentive would help to address stakeholders' most pressing concerns and ensure that the 2019/2020 Solar Transition proceeds as smoothly as possible.

Recommendation 2: Structure of the Transition Incentive Program

Staff recommends that the Transition Incentive be a TREC. The TRECs created by eligible projects would be jointly procured by the EDCs to satisfy a new compliance obligation tied to a TI-RPS. Existing parallel to, and 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 Transition Incentive should be structured, Staff believes, as a factorized renewable energy certificate. The factors would allow the TREC to provide differentiated financial incentives for different installation types. The factors assigned would be tied to the estimated costs of building the different types and to their varying revenue expectations under basic retail rate tariffs or wholesale market prices. In each case, the goal of the factorization program is to ensure that ratepayers are providing the minimum necessary financial incentive to develop diverse types of projects, consistent with maintaining a healthy solar industry in New Jersey. Thus, projects with the largest gap between project costs and revenues would receive the largest incentive – that is, these projects would receive a factor of 1.0 so that, when the base incentive was multiplied by the factor, it would remain at the original dollar per MWh value. Projects with a smaller gap between costs and revenues, that do not need as large an incentive, would be assigned a percentage factor of the base incentive amount (also known as the base compensation value).

The recommended factors are as follows:

Project Type	Factor
Subsection (t): landfill, brownfield, areas of historic fill.	1.0
Grid supply (subsection (r)) rooftop	1.0
Net-metered non-residential rooftop and canopy	1.0
Community solar	0.85
Grid supply (subsection (r)) ground mount	0.6
Net-metered residential ground mount	0.6
Net-metered residential rooftop and canopy	0.6
Net-metered non-residential ground mount	0.6

In the case that a project may be eligible for multiple factors, the lower factor project classification would apply.

Recommendation 3: Eligibility for the Transition Incentive

Staff recommends that the Board make the TI available to projects that submitted complete SRP registrations, subsection (t), or subsection (r) applications after October 29, 2018 and remain in the SREC SRP pipeline because they have not received Permission to Operate at the time that the Board determines that the 5.1% Milestone has been attained. Projects that submitted complete SRP registrations, subsection (t), or subsection (r) applications prior to the 5.1% Milestone date and received Permission to Operate prior to the date of attainment of the 5.1% would be eligible for the Legacy SREC program. Staff believes that this approach will be fair to the pipeline projects and also clearly delineates the Transition Incentive Program from the Legacy SREC Program.

Recommendation 4: Mechanism for Creation of TRECs

Staff recommends that TRECs be created in the same manner as SRECs, based upon metered generation supplied to GATS by the owners of eligible facilities or their agents. GATS would create one TREC for each MWh of energy produced from a qualified facility. Staff proposes that each eligible solar facility would be provided a TREC factor by Staff, which would be applied to each TREC created by GATS. TRECs would be redeemable in the year in which the electricity was produced or the following Energy Year (*i.e.*, have a useful life of 2 years). Projects would be eligible to generate TRECs for 15 years ("TI-Qualification Life" or "TI-QL") following commencement of commercial operations; after which time, projects may be eligible for a NJ Class I REC.

Recommendation 5: Value of a TREC

Staff recommends that the Board establish a fixed TREC. A fixed TREC provides additional certainty to the market participants, and certainty is particularly important at this time and for the universe of projects anticipated to be in the Transition Program. The Board must close the existing incentive program, which has enabled a successful solar market in the State, and market participants are understandably concerned. In addition, the projects that will be in the pipeline when the Board announces the attainment of the 5.1% Milestone will contain a number that may have been designed and financed in the expectation of commencing commercial operations as participants in the Legacy SREC program. Other projects may simply need to know what to expect. In either case, and for all the pipeline projects, a fixed incentive provides valuable certainty and predictability.

Staff recognizes that a base compensation level respecting the kink period, while potentially mitigating the risk of breaching the cost cap, presents a number of challenges. As the summarized comments above show, stakeholders have expressed concerns about the implementation of a custom ACP in response to the kink period. Many indicated that the revenues in the first three years would be too low to adequately support the solar industry, and that the existence of a kink period custom ACP would significantly complicate financing for these projects, therefore increasing financing costs. While recognizing these concerns, Staff believes that further clarification of the cost cap is needed to determine whether a flat compensation of $152/MWh for 15 years would also allow for the development of a Successor Program and stay under the cost caps.

Therefore, Staff is recommending that the Board initiate a proceeding on the calculation of the cost cap on an expedited basis, focusing on the suggestions made by various stakeholders. At the outcome of this new proceeding, if it is determined that there is sufficient headroom available under the cost cap to both allow for a flat TREC value of $152/MWh and develop a robust Successor Program, the Board could opt to eliminate the lower base compensation levels created to accommodate the kink period and smooth out the TREC value to a flat $152/MWh for 15 years.

However, until the Board makes an affirmative determination that the kink period is not a concern, Staff recommends that the Board adopt a conservative approach to TREC pricing that includes a lower initial TREC price of $65/MWh in EY2021, EY2022, and EY2023, followed by $189/MWh for the remainder of each project's 15-year QL. Modeling indicates that the cost cap is at highest risk of being breached during EY22 and EY23: the step-down from a 9% cost cap to a 7% cost cap occurs at the end of EY21, at a time when the volume of the Legacy SREC program remains high. The initial three-year kink period custom ACP would lead to lower TREC prices and therefore to lower Transition Incentive program compliance costs during these three years. As a result, the total cost of Legacy and Transition incentives would be less likely to exceed the cost caps established by the Clean Energy Act. After EY23, the TI-ACP would be increased to ensure that projects receive the full value of the incentive required to develop a project.

Staff anticipates that the Board will decide to either select the shaped or flat TREC values at the completion of the new proceeding and in advance of reaching the 5.1% milestone.

Staff notes that both methodologies result in a TREC value of approximately $152/MWh, averaged out over 15 years. This Base value was developed in part based upon modeling conducted by the Consultant, informed by stakeholder comments. The proposed Base Compensation rate was initially drawn from the Consultant's Revised Modeling Addendum, published in October 2019.[17] The subsequent revision of the Consultant's Modeling Addendum in November 2019 lowered the Consultant's incentive gap findings. However, the stakeholder comments made at public meetings and in the comments summarized above, including alternate models and assumptions provided by industry participants, indicate that stakeholders were concerned that the Consultant's revised incentive gap findings are too low to support most projects currently in the SRP pipeline. Stakeholders also expressed concerns with the assumptions used in the Consultant's modeling. As such, Staff believes it is justified to maintain the Base Compensation recommended rate at the prior level, subject to the factors described above.

Recommendation 6: Terms for TRECs

Staff recommends that TRECs have a useful life of two years (*i.e.*, be able to be redeemable in the year in which the electricity was produced or the following Energy Year). TRECs would be able to be sold to the TREC Administrator in the year in which the electricity was produced or the following Energy Year. However, they would be compensated at the TREC value set for the Energy Year in which the electricity is generated. If the TREC is not redeemed via entry of metered generation data and sold within two years of the underlying electricity generation, the electricity would be eligible to form the basis of a New Jersey Class I REC. Solar electric generation facilities would be able to create TRECs for fifteen years following commencement of commercial operations.

Recommendation 7: TI-RPS Compliance

Staff recommends that the Board require the EDCs to purchase TRECs from eligible facilities. Assigning this role to the EDCs would greatly simplify the implementation of the TI program by establishing a single pathway for purchase of the TRECs, as well as enable the apportionment of costs in a competitively neutral manner, consistent with the goals established in the Clean Energy Act. Staff further notes that a fixed price TREC eliminates the possibility that competitive forces might produce lower TREC costs. Without that potential benefit, the primary reason for assigning the compliance obligation directly to the TPS and BGS providers is eliminated.

To further this arrangement, Staff recommends that the Board direct the EDCs to jointly assign or procure a TREC Administrator. The TREC Administrator would procure all valid TRECs on a must-purchase basis, under contract with the EDCs. The GATS system would be used to facilitate the procurement and collection of TRECs, which would follow the normal RPS compliance schedule. As part of the annual RPS compliance process, the Board will instruct the TREC Administrator to allocate TRECs to Load Serving Entities ("LSEs") as appropriate. The LSEs will then retire the TRECs within the GATS system. Costs for the TRECs procured and TREC Administrator fees would be recovered from ratepayers by EDCs based upon each EDC's proportionate share of retail electric sales.

[17] The Consultant's recommendation proposed that the Base Compensation rate would be different for each of the first three years: $65 in EY2021, $59 in EY2022, and $53 in EY2023. Staff recommended that the rate be a flat $65 over these three years.

FINDINGS AND DISCUSSION

The Board has reviewed the extensive record in this proceeding regarding proposed changes to the policies and regulations that guide New Jersey's solar marketplace. New Jersey has become one of the most vibrant solar marketplaces in the world, and the Board is committed to maintaining our State's position as a marketplace leader, while at the same time taking steps to control ratepayer costs. The various stakeholders who participated in this proceeding have brought considerable dedication and passion to the process of transitioning the solar market. The Board recognizes that our decision herein will significantly impact the solar marketplace in general and many of the solar businesses that have taken root in New Jersey over the past two decades. The Board is concerned as well with the impact of our decision in this matter on the State's residential and low-income customers, as well as other business and industries in the State.

The Clean Energy Act directs the Board to complete a study that evaluates how to modify or replace the SREC program so as to encourage the continued efficient and orderly development of solar renewable energy generating sources throughout the State. N.J.S.A. 48:3-87(d)(2).

The Board **HEREBY ORDERS** the creation of a Transition Incentive program, comprised of fixed-price TRECs.

The Board **HEREBY ORDERS** that projects that submitted complete SRP registrations after October 29, 2018, that have yet to commence commercial operations but otherwise remain in good standing in the SRP pipeline at the time that the Board determines that the 5.1% Milestone has been attained, will be eligible for the TI. The Board **HEREBY DETERMINES** that these projects eligible for the TI will not be eligible for the to-be-determined Successor Program. The Board **FURTHER DETERMINES** that projects having not entered the SRP queue, having been found to be incomplete, or whose SRP registration has expired at the time the 5.1% Milestone is attained will not be eligible for the Transition Incentive. The Board **ORDERS** that projects eligible for the TI must comply with all rules and regulations of the SRP. Upon completion of the project, and in compliance with all existing rules and regulations of the SRP, the Board **DIRECTS** the SRP Program Administrator to issue projects a TREC Certification Number. The Board **ORDERS** that TRECs be created based upon metered generation supplied to GATS by the owners of eligible facilities or their agents, with one MWh being the basis for the creation of one TREC.

The Board **FURTHER DIRECTS** the SRP Program Administrator to differentiate and denote the TREC Certification Number by project type, using the factors set out as follows:

Project Type	Factor
Subsection (t): landfill, brownfield, areas of historic fill.	1.0
Grid supply (subsection (r)) rooftop	1.0
Net metered non-residential rooftop and carport	1.0
Community solar	0.85
Grid supply (subsection (r)) ground mount	0.6
Net metered residential ground mount	0.6
Net metered residential rooftop and carport	0.6
Net metered non-residential ground mount	0.6

The Board **HEREBY SETS** the base compensation for a TREC as follows: $65/MWh for EY2021, EY2022, and EY2023, and $189/MWh for the remainder of each project's 15 year TI Qualification Life. The actual value of a TREC will be calculated based upon the factor assigned to each project, by multiplying the base compensation value for the appropriate year by the factor.

The Board **DIRECTS** Staff to initiate a proceeding on the calculation of the cost cap, and to report back to the Board regarding the recommendations and outcomes of said proceeding, at which point the Board will provide further guidance on whether to remain with the shaped TREC methodology or adopt the alternative flat TREC value of $152/MWh.

The Board **ORDERS** that TRECs will be created based upon metered generation supplied to GATS by the owners of eligible facilities or their agents. GATS will create one TREC for each MWh of energy produced from a qualified facility. The Board **FURTHER ORDERS** that TREC creation be based on the year in which the electricity is produced and have a useful life of 2 years, *i.e.*, TRECs are able to be sold to the TREC Administrator in the year in which the electricity was produced or the following Energy Year. TRECs will receive the factorized value associated with the Energy Year in which the energy was produced, and the owners of eligible facilities or their agents will be required to certify the year in which the energy was produced. If the TREC is not produced or sold within two years of the electricity being generated, the Board **ORDERS** that the electricity can form the basis of a NJ Class I REC.

The Board **ORDERS** that solar electric generation facilities be permitted to create TRECs for fifteen years following commencement of commercial operations (the project's TI-Qualification Life); after this time projects may be eligible for a NJ Class I REC.

The Board **HEREBY DIRECTS** the EDCs to work with Staff to jointly procure a TREC Administrator. The Board **ORDERS** the EDCs' TREC Administrator to use the GATS system to purchase all TRECs produced each year by eligible projects. The Board **DEFINES** the total sum of TRECs retired each year as the TI-RPS, and **FURTHER DEFINES** the TI-RPS as a carve-out of the existing Class I REC RPS, reducing the required amount of RECs on a one-to-one basis by the amount of TRECs retired. The Board **FURTHER DIRECTS** the TREC Administrator to allocate TRECs to LSEs based on market share of retail sales for retirement within the GATS system as part of the annual RPS compliance process.

The Board **HEREBY DIRECTS** that the incentive levels, once set, will not be revisited for the duration of the term of the Transition Incentive program, barring any changes in law, in order to provide certainty to the industry.

The Board **HEREBY ORDERS** that the EDCs may recover reasonable and prudent costs for TRECs procurement and TREC Administrator fees. Recovery shall be based on each EDC's proportionate share of retail electric sales. Each EDC shall make an annual filing for its costs and the recovery method, which shall be subject to approval by the Board.

This Order shall be effective on December 16, 2019.

DATED: 12\6\19

BOARD OF PUBLIC UTILITIES
BY:

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PRESIDENT

MARY-ANNA HOLDEN
COMMISSIONER

DIANNE SOLOMON
COMMISSIONER

UPENDRA J. CHIVUKULA
COMMISSIONER

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COMMISSIONER

ATTEST:

AIDA CAMACHO-WELCH
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

IN THE MATTER OF A NEW JERSEY SOLAR TRANSITION PURSUANT TO P.L. 2018, C.17
DOCKET NO. QO19010068

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