February 22, 2019

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RE: Comments on New Jersey's Solar Transition Staff Straw Proposal

On December 26, 2018, the BPU published a straw proposal and schedule for a continued stakeholder process to inform its rules for the New Jersey solar transition required by P.L. 2018, c.17 (the "Act").

As the Board tackles this challenge, the overarching purpose of the Act should remain front and center. The Act's purpose is to accelerate New Jersey's reduction of greenhouse gas emissions to combat climate change, one of the greatest threats facing our state, today and in the future. To achieve these reductions, the Act relies, in large part, on the growing renewable energy requirements and successfully meeting them through continued successful competitive deployment of renewable energy resources.

The Board is now deliberating how best to implement Act requirements that are central to whether New Jersey will indeed be able to reach 50 percent renewable energy by 2030. Our comments are intended to help inform the Board on how to implement these requirements in a way that will ensure these goals will be met, while supporting continued growth of in-state solar resources and fair treatment of existing solar projects.

We believe that it is critically important to achieve each of the following goals in the solar transition:

- Fully meet the interim and 2030 renewable energy requirements of the Clean Energy Act,
- Provide adequate SREC-based revenues to maintain the economic viability of existing legacy solar investments,
- Support continued growth in new solar projects in New Jersey to help meet the RPS goals and state's overall clean energy and global warming reduction goals,
- Do this within the legislatively mandated caps (including net ratepayer benefits from the RPS expenditures) on ratepayer cost for meeting the Class 1 renewable energy goals.

To better achieve all these goals, we recommend the BPU issue a revised and significantly more detailed and less ambiguous straw proposal by April. By removing the ambiguity or vagueness of certain aspects of the current straw proposal, as explained in these comments, this revision will help stakeholders provide specific, detailed support or constructive criticism, including on how the various key elements of the straw proposal will or will not work well together. We also recommend refining and clarifying the straw proposal's SREC transition principles and assumptions to better support constructive stakeholder engagement and convergence on SREC transition policies that can best achieve the requirements of the Clean Energy Act and the state's other clean energy goals.

Brief answers to select staff questions:

1. **For the solar transition and the state's clean energy goals to succeed, the BPU will need to actively manage the budget created by the cost caps, rather than merely monitoring it.** The proposal to "over an 18-month period, closely monitor the price cap to ensure that it is not exceeded, with the recognition that the Board could exercise its authority to reduce the Class I RECs in the event of the cap being exceeded" falls substantially short of the CEA's requirement that the BPU "do anything necessary" to ensure the RPS costs do not exceed the cost caps.

2. **The SREC program has performed poorly over the past 5 years. Key failures, all of which are inherent in the basic SREC market model, include:**
    a. Excessive volatility and uncertainty regarding future price level (caused by near vertical demand and supply curves and causing higher capital costs than fixed price contracts or similar longer-term compensation approaches would).
    b. A single SREC price for solar of various vintages and costs is guaranteed to over-compensate newer, lower cost solar projects and under-compensate older, higher-cost projects (this is inefficient and leads to higher costs for ratepayers than needed for a given amount of solar energy).
    c. Both a and b have led, understandably, to continued political pressure by solar interests to increase the solar requirement in order to produce higher SREC prices.

3. **A fixed (administratively determined) SREC price or price schedules offers important advantages over other options but may impair important existing SREC contracts. An administrative price:**
    a. Can be designed to ensure the RPS goals and budget are met;
    b. With careful stratification of solar vintages, banking and limited borrowing of budget surpluses, and recognition of moderate net ratepayer benefits, can fit within cost caps while compensating older legacy solar at levels close to historic SREC price levels and newer legacy solar at levels consistent with costs;
    c. Lends itself to easier budgeting and planning of how to manage the RPS budget and meet the RPS goals and other state clean energy goals;
    d. However, a fixed administrative price may interfere with many current SREC sale and hedging contracts, which rely on the current trading market.

    To gain these benefits but avoid the problems, the Board should explore ways to stabilize SREC prices at sustainable levels, while retaining the trading market for legacy SRECs.

4. **The Board should make no more use of any program like the current SREC program for either the Pipeline or the Successor program.** Pipeline projects are virtually certain to have much lower costs than most Legacy projects, so using the same single legacy SREC price to compensate both types will almost certainly be both inefficient and unfair. We recommend new solar programs feature more stable incentive levels, based on market indicators of the costs of each annual cohort of new solar, paid over a long enough period to ensure low cost financing for solar developers.

5. **Net ratepayer benefits from RPS resources can be used to adjust the cost caps upwards consistent with the statute**. The statute's RPS cost caps are for costs to ratepayers, not on broader social costs. Accordingly, to better withstand any challenges, for this purpose of adjusting the cap, we recommend that the Board at this time count only net benefits to ratepayers, including any ratepayer health and environmental benefits from emissions avoided by the RPS. Broader analysis of clean energy costs and benefits should be developed for use in the state's clean energy planning and management for achieving its clean energy goals and developing new RPS incentives. Once established, this process should also be used to most accurately identify the net costs of the RPS requirements to ratepayers.

Appendix 1 contains detailed explanations and responses to topics raised in the straw proposal. Our comments describe an integrated set of solutions that achieve multiple goals: developing high levels of renewable energy, ensuring the continued growth of the solar industry in New Jersey and protecting ratepayers within the parameters set by the Clean Energy Act.

We look forward to continuing our discussions with BPU staff, solar developers and other stakeholders to identify workable solutions that will provide an orderly transition to a new solar program.

Respectfully submitted,

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Appendix 1

I. Main point and objective of comments -- Reinforce and encourage further clarity on need to achieve all the following in an integrated manner:

- Fully meet the interim and 2030 renewable energy requirements of the CEA,
- Provide adequate SREC-based revenues to maintain the economic viability of existing legacy solar investments,
- Support continued growth in new solar projects in New Jersey as a part of the RPS goals and state's overall clean energy and global warming reduction goals,
- Do this within the legislatively mandated caps (including any real, measurable, net ratepayer benefits from the RPS expenditures) on ratepayer cost for meeting the Class 1 renewable energy goals.

To achieve all these goals, we recommend the BPU take the following steps:

1. Issue a revised and significantly more detailed and less ambiguous straw proposal at or prior to the commencement of the working groups and workshops proposed for April through July of this year. By removing the ambiguity or vagueness of certain aspects of the current straw proposal, as explained in these comments, this revision will help stakeholders provide specific, detailed support or constructive criticism, including on how the various key elements of the straw proposal will or will not work well together.
2. Further refine and clarify the straw proposals SREC transition principles and assumptions, as explained in these comments, to better support constructive stakeholder engagement and convergence on SREC transition policies that can best achieve the requirements of the Clean Energy Act and the state's other clean energy goals.

II. Response to request for comments.

The Proposal requests discussion and consideration of four basic elements of a transition frame-work, and of 13 specific questions (Proposal, p. 4). The Environmental Parties respectfully offer the following comments in response.

1. Elements 1 and 4 of the transition frame-work.

a) Proposing to define "attained" as when "5.1% of the actual kilowatt-hours sold in the state come from solar electric power generators."

The proposed definition is too vague to inform stakeholders as to when the program is likely to close. This uncertainty creates substantial market, policy and business continuity risk for the solar industry and has major implications for whether and how the RPS goals can be met within the budget, including legacy solar compensation, created by the statutory RPS cost caps. This uncertainty over timing, together with the uncertainty over SREC price levels for legacy projects after the program closes, needs to be resolved quickly through a revised straw proposal with sufficient detail for stakeholders to understand and either support or criticize constructively.

The statutory target for closing the SREC program to new applications consists of a fraction with the kWh of solar generated in an energy year by qualified solar projects in the numerator, and the total kWh of retail sales in the same energy year in the denominator. But the straw proposal uses the past tense (*actually sold*) for the kWh in the denominator, and the present tense (*come from*) for the kWh in the numerator.

This means the fraction could be calculated in at least two ways. It could be done after the fact, dividing the solar kWh *actually sold* by solar projects in the previous energy year by the retail kWh *actually sold* by load serving entities (LSEs) in the same year. Or it could be done before the fact, using projections based on the total kWh projected to *come from* solar projects in the current energy year, divided by the projected total kWh that load serving entities will *sell to* retail customers in the same energy year.

Due to the size of the current pipeline of applications, using projections for the numerator and the denominator could result in the 5.1% trigger being reached in the near future, during the 2019 energy year. This projected approach would also result in a very tight or potentially even a short legacy SREC market after the program is closed, with prices so high they could prevent achievement of the RPS goals within the budgets created by the statutory cost caps.

Avoiding this result would require the BPU to take steps to keep legacy SREC prices at or below levels that would allow the RPS goals to be met, including by new solar, not just on a year-by-year basis, but prospectively. And, to ensure business continuity for the state's solar industry, it would require more rapid implementation of Pipeline and Successor programs.

By contrast, using after-the-fact amounts of solar and retail energy actually sold in the numerator and the denominator could well result in closing the program at the end of energy year 2010, a year or more later. Without adequate amounts of attrition or deferral of new solar projects, this additional year or more of solar development would almost certainly cause the SREC market to be long in future years, due to the fact that many of the projects that start in the next energy year will only operate in part of it, but will operate in all of subsequent years. With high levels of attrition and deferral, the closed legacy SREC market could still produce prices that prevent enough new solar and other Class 1 resources to meet the RPS goals within the cost caps' budget, so the BPU would still need to take steps to prevent such excessively high prices. But with ample entry and little attrition or deferral, legacy SREC market prices could collapse to levels that could impair some legacy projects, despite the proposal's goal in element 2 "to ensure that the current market does not become over-supplied".

To avoid prices that are either too high or too low, if the BPU implements the after-the-fact approach, it should develop means to protect against both excessively high and excessively low legacy SREC prices. However, the after-the-fact approach would allow more time to develop both the Pipeline and Successor programs.

Unfortunately, the Proposal is unclear regarding whether it calls for a projected or an after-the-fact determination of the 5.1% trigger. As a result, none of the issues SREC price, business continuity and RPS budget issues that will be directly affected by which type of trigger is used, can be anticipated on the basis of the Proposal.

Because the success of the solar transition depends on how the BPU addresses these issues, the staff should issue a revised and clarified straw proposal that makes it clear

- whether the 5.1% trigger will be based on projected or after-the-fact measurements of solar and retail energy sales,
- when the staff anticipates the program will close,
- the preferred approach or alternatives to manage legacy SREC prices so they are fair and so the RPS goals can be met within the statutory cost caps, and
- its proposed timeline for the start of the Pipeline and Successor programs.

This revised straw proposal should be issued prior to or at the beginning of the stakeholder process proposed to start in April of this year.

b) Proposing to "over an 18-month period, closely monitor the price cap to ensure that it is not exceeded, with the recognition that the Board could exercise its authority to reduce the Class I RECs in the event of the cap being exceeded."

This proposal is woefully inadequate to meet the CEA's requirement that the BPU "do anything necessary" to ensure the RPS costs do not exceed the cost caps. First, simply monitoring is not enough; the statute obviously requires the BPU to actively manage, including by continually planning, budgeting and evaluation, the way the RPS program is implemented. This includes planning and balancing the costs of legacy solar, against those for new solar and for other Class I renewables needed to meet the RPS goals. This process requires both planning and management because the state will be taking on the obligation to meet future RPS costs years before they occur, through commitments to recurring incentive payments for legacy solar, new solar and, potentially, for other Class I renewables needed to meet the goals. Monitoring the current year, or the next 18 months, without accounting for future committed recurring expenditures, is like deciding one can afford to buy a new car on credit because one has enough money right now to make the payments for the next year, without considering the ability to keep making the payments for the life of the contract.

The next 18 months, which appears to be the scope of this proposal, are particularly important to the state's ability to meet its statutory RPS obligations. Quite simply, the high volume and potential high prices of legacy SRECs during this period, together with whatever amount of Pipeline and Successor solar the BPU creates commits to recurring incentive expenses for, could stay within the annual budget for the next year or two, but use up so much of the overall budget going forward that there simply would not be enough in subsequent years for meeting the RPS goals within future caps, or even for very much additional new solar. This is especially important because the statutory budgets are higher for the first three years, and then fall from 9% of retail sales to 7%. Any long-term commitments, whether for Legacy, Pipeline or Successor solar projects, made in these early years need to anticipate the 7% caps, not just the early 9% caps.

2. Answers to specific staff questions, as numbered.

1. *SREC program evaluation.* The SREC program has performed poorly over the past 5 years. Key failures, all of which are inherent in the basic SREC market model, are:
    a. Excessive volatility and uncertainty regarding future price level (caused by near vertical demand and supply curves, and causing higher capital costs than fixed price contracts or similar longer-term compensation approaches would)
    b. A single SREC price for solar of various vintages and costs is guaranteed to over-compensate newer, lower cost solar projects and under-compensate older, higher-cost projects (this is

inefficient and leads to higher costs for ratepayers than needed for a given amount of solar energy)

c. Both a and b have lead, understandably, to continued political pressure by solar interests to increase the solar requirement in order to produce higher SREC prices.

2. *SREC successor program organization re SREC price determination.* The key pros and cons of the three alternatives are as follows.
    a. A fixed (administratively determined) SREC price or price schedules:
        i. + Can be designed to ensure the RPS goals and budget are met;
        ii. + With thoughtful stratification of solar vintages, banking and limited borrowing of budget surpluses, and recognition of moderate net ratepayer benefits, can support budget while compensating older legacy solar at levels close to historic SREC price levels and newer legacy solar at levels consistent with costs;
        iii. + Lends itself to easier budgeting and planning of how to manage the RPS budget and meet the RPS goals and other state clean energy goals;
        iv. – Would require significant regulatory and other changes to the current transactional, pricing and accounting mechanisms that transfer SRECs to LSEs, transfer SREC value to SREC sellers or holders, and hedge SREC price risk;
        v. - Dramatically modifies the current SREC trading market and could result in exercise of "regulatory out" clauses in many SREC supply and hedging contracts, which could in turn make compensation of the party or party holding the legacy SRECs difficult or perhaps impossible.
    b. A market-determined SREC price:
        i. + Would not require significant changes to the current transactional and regulatory accounting mechanisms;
        ii. +would not be likely to trigger "regulatory out" clauses in SREC supply and hedging contracts;
        iii. – would be difficult or even impossible to manage in ways that would ensure meeting the RPS and other state clean energy goals within the statutory RPS budget, especially in light of the goal of avoiding oversupplying the current SREC market;
    c. Alternative options that preserve the pros of (a) and (b) while reducing or avoiding the cons:
        i. Maintain the current trading and transactional mechanisms, but add:
            1. An effective price cap in the trading market at a level or levels which, over time, ensure the ability to meet the RPS and other clean energy goals within the statutory cost cap;
                a. A cap could consist of an "RPS Cost Control Payment" (RCCP) that would function much as the SACP does, but for a different purpose and at a different, lower level.
                b. Using such an RCCP would establish only a single price for all legacy projects. If the BPU determines that it will be fairer and more efficient to compensate older vintage legacy projects at a higher level than new vintage projects, it may be able to do this under the RCCP approach by setting the RCCP at the level that is fair to newer SREC projects, and providing a separate multiplier payment to older

vintage projects, which would be allocated pro-rata across all load-bearing entities.

2. An effective price floor (if the SREC market becomes oversupplied due to the BPUs final approach to determining the 5.1% "transition point" as discussed above).
    a. A floor, if needed due to an excess of legacy SRECs, could consist of a relatively low price at which BGS providers would be required to buy, retire, and allowed to recover costs from their customers, of any SRECs that are due to expire.

A price cap will be particularly necessary if the SREC program is closed without creating an oversupply. However, if there is no oversupply, a price floor will not be needed or, if adopted, would be very unlikely to be triggered or used.

3. *How these SREC price determination approaches could be implemented.* There are two different steps in determining an appropriate SREC price level or levels over time. The first is to arrive at a determination of what level or levels of compensation would generally be sufficient to treat legacy SREC holders fairly, for example, levels that would by and large prevent economic impairment of existing legacy projects and portfolios. The second is to determine whether compensation at such a level or levels, during the remaining tenor of the solar mandate, preserves enough of the RPS budget (as adjusted for banking, limited borrowing and net ratepayer benefits) to meet the RPS goals in future years.

    The BPU will need to balance these issues of fairness with its decisions about adjusting the RPS budget for benefits, banking and limited borrowing (as discussed in our answers to questions 9 and 10, below), and with the pros and cons of the different mechanisms it chooses to actually manage the SREC price levels, as discussed in our part (c) of our answer question 2 above.

4. *Legacy SREC valuation in relationship to Successor Program.* Legacy SRECs should be valued separately from Successor SRECs, for two primary reasons:
    a. Due to the falling costs of solar, Legacy SREC costs are typically far higher than those of current and future solar projects, and compensating legacy SRECs at new solar costs may be considered unfair to legacy SREC holders;
    b. The "regulatory out" problems identified above would likely be triggered by any approach that links Legacy SREC compensation to Successor program prices, which the CEA anticipates being produced by means other than a single, tradeable solar energy credit for all types and vintages of solar projects.

5. *Pipeline SREC valuation and related questions.* We understand this question as follows:
    a. "How should Pipeline SRECs be valued?" we read as asking how should Pipeline Solar incentives be designed, what payment or price levels should they have, and how will those incentives be used for compliance with the RPS once the solar mandate is fully met by legacy projects;

b. "Should these Pipeline SRECs be valued under the SREC Successor Program or valued separately?" we read as asking if the Pipeline incentives should be identical to, or at least priced in some way through, the Successor Program;
c. "Should the Board continue the current SREC program as a separate program, and if so, how?" we read as asking if the Pipeline projects should be compensated through a new program, similar in design to but separate from, the legacy SREC program;
d. "Should the Board include the current SREC program within the SREC Successor Program, and if so, how?" we read as asking if either
    i. the legacy SREC program or
    ii. a Pipeline program that is similar in design to, but separate from, the legacy SREC program, or
    iii. should itself be somehow included with the SREC successor program.

Our answers are:

a. We recommend Pipeline solar incentives be valued and utilized separately from legacy SRECs. Once the legacy SREC program is closed to new entry, there should be enough SRECs from legacy projects to meet the requirements of the Load Serving Entities to meet the statutory solar mandate. Pouring additional credits from the Pipeline projects into the same compliance pool (i.e., using them to also meet the statutory solar mandate) would dilute the pool and reduce legacy SREC prices. While this might offer an approach to managing legacy SREC costs, we do not recommend it because of the uncertainty about its price impact and the underlying potential for high levels of price volatility in the closed SREC market that it could create. Further, this inability to predict the price impact is made even worse, at this time, by the uncertainty about how the BPU will measure the 5.1% trigger for closing the SREC program. Also, the Pipeline projects are virtually certain to have much lower costs than most Legacy projects, so using the same single legacy SREC price to compensate both types will almost certainly be both inefficient and unfair. For all these reasons, we recommend against using Pipeline renewable energy credits to satisfy the legacy solar mandate.

   Instead, we recommend Pipeline solar energy be used to satisfy the broader Class I RPS, above and beyond the statutory solar mandate, and without a new additional solar mandate crafted by the BPU. We recommend that Pipeline incentives be valued based on either a showing or a reasonable estimate of competitive new solar cost, net of expected revenues from customers, and preferably by the separate categories of C&I, residential rooftop, and grid scale.

   One tried and true approach to competitive pricing for longer term tranches is New Jersey's SREC II program, which we believe could be modified for use in either the Pipeline or Successor programs. Whether valued (i.e., priced) through a bidding program, as in the existing SREC II program, or priced through some other cost-determination, as contemplated for the modified or replaced SREC program in the Clean Energy Act, the renewable energy credits created by the Pipeline and Successor programs could be aggregated, transferred to compliance entities, and have payment settled in a manner structurally similar to the way in which ORECs are to be aggregated, transferred to compliance entities, and have payment settled in the Board's new rule for Qualified Offshore Wind Projects, N.J.A.C 14:8-6.6 and 6.7. Note, however, we strongly recommend against using a similar price-determination methodology of the offshore wind rule in the Pipeline and Successor solar programs.

We view such a separate, cost-based Pipeline incentives as a fast and early approach to what the eventual Successor program should look like. Key design concepts for both programs would include: competitive cost benchmarks by solar type; fixed payments for annual tranches at that incentive level for a 10-year or longer incentive schedule; annual determination of the cost level for new 10-year tranches of each type of solar; energy production or renewable energy credits from projects used for RPS compliance separately from legacy solar mandate. However, even with a common design framework, the Pipeline program should be considered as a separate program due to the limited time that may be available for its development and the limited MW it will be open to.

b. We recommend against using the legacy SREC approach for Pipeline projects, by which we mean a traded SREC market used to source and price SRECs needed for compliance by load serving entities, who are required to meet a new, additional solar mandate that the Board would create. Such an approach would have numerous problems, on top of the design flaws inherent in such a market, as articulated in our answer to Question 1 above. Key problems in this application would include:
    i. The market would be extremely thin and illiquid, since the number of Pipeline projects will be small,
    ii. The market would be extra risky, since it would depend on a regulatory rather than a statutory mandate,
    iii. The price uncertainty and risk premium due to the above two factors would be very large, and create unnecessary and unreasonable costs for ratepayers and for solar investors alike,
    iv. Such a program would over-compensate some types of solar and under-compensate others, due to their different costs and revenue opportunities, and would thus perpetuate and aggravate the inefficiency and instability of the current SREC program.

c. Our answer to (d) above is explicit in the previous answers – the Board should make no more use of any program like the current SREC program for either the Pipeline or the Successor program. Instead, it should follow the clear guidelines in the CEA for how those programs should be designed, and convert the renewable energy compensated through those programs into RECs (or "SREC 2.1") that would be made available to LSEs for compliance purposes in consideration of the incentive payments received by the solar projects.

6. *Should the Board set MW targets for new solar construction in the transition, and if so, how?* During the transition, e.g., for the Pipeline program, the Board should use a budget-based approach to setting MW targets, so that it avoids inadvertently committing to more recurring future expenses than are consistent with meeting the RPS goals within the statutory RPS cost caps. This approach is described in more detail in our answer to the next question.

7. *Should the Board set MW targets for the Successor Program?* For the Successor program, the Board needs to actively plan and manage the budget to meet the RPS goals, as discussed above. This means projecting and managing to a dollar budget for new and recurring solar incentive expenditures in each year. This is essential because the RPS cost caps are denominated in dollars, not in MW. Once these dollar budgets are established, the number of MW to be procured in each year can be determined, e.g. as follows:
    a. Determine the total amount of the budget (net of any banking, borrowing and offsetting net ratepayer benefits) that remains for each coming year, after accounting for
        i. projected recurring payments for Legacy, Pipeline and prior Successor programs for each year, and
        ii. projected recurring payments for prior commitments for other Class 1 renewable energy (procured as RECs) for each year;
    b. Spread that remaining budget for each year over the combination of new solar MW and new Class 1 RECs that achieves all three of the following objectives:
        i. Maximizes the amount of new solar, while also
        ii. Procuring enough new Class 1 RECs to meet the RPS goals, and
        iii. Allows the RPS goals in future years to be achieved without exceeding the budget in any future year.
    c. This means spreading a given amount of money (determined in Steps (a) and (b) over as much new solar as it can buy while meeting the RPS goals and without exceeding the budget in the current year and, as projected, in each year going forward. This is inconsistent with simply setting MW goals without a current and future year budget constraint. Instead, the Board must set dollar budgets and then using competitive procurement, declining block tariffs, or similar incentive programs, such as are required by the CEA, to get the most amount of new solar for those dollar budgets, while preserving enough money in the budget to also procure enough lower cost RECs to achieve any unmet portion of the RPS goals in the current year and, similarly, for each future year. The amount of MW so procured could be expressed as a percent of total retail sales or as a share of the total RPS requirement, but this form of expression should always be based on a budget consistent with meeting the RPS goals.
    d. Because these budget plans involve forward projections, it is essential to update them each year for actual costs and changes in projected future costs. This approach could ideally be coordinated with or integrated into the states Energy Master Planning process.

8. *Should the Board provide differentiated incentive payments by type of Successor program solar projects?* We believe such differentiated payments, to the extent the Board finds them well-advised and has the authority and the ability to set them up, are required by the Clean Energy Act, which provides as follows:

The board shall consult with public utilities, industry experts, regional grid operators, solar power providers and financiers, and other State agencies to determine whether the board can modify the SREC program such that the program will:

- *Continually reduce, where feasible, the cost of achieving the solar energy goals set forth in this subsection;*
- *Provide an orderly transition from the SREC program to a new or modified program;*
- *Develop megawatt targets for grid connected and distribution system systems, including residential and small commercial rooftop systems, community solar systems, and large scale behind the meter systems, as a share of the overall solar energy requirement, which targets the board may modify periodically based on the cost, feasibility, or social impacts of different types of projects;*
- *Establish and update market-based maximum incentive payment caps periodically for each of the above categories of solar electric power generation facilities;*
- *Encourage and facilitate market-based cost recovery through long-term contracts and energy market sales; and*
- *Where cost recover is needed for any portion of an efficient solar electric power generation facility when costs are not recoverable through wholesale market sales and direct payments from customers, utilize competitive processes such as competitive procurement and long-term contracts where possible to ensure such recovery, without exceeding the maximum incentive payment cap for that category of facility.*

In our view, the third item in this list's mention of the MW targets "as a share of the overall solar energy requirement" is problematic as written, given this same section's requirement to close the SREC program to new projects when it reaches enough to fully satisfy the remaining solar mandate. If the SREC program is closed to new projects, it appears impossible for new solar projects to contribute to the compliance requirement that is already being met by the legacy projects. It seems unlikely that the legislature meant this, since it makes no sense and would clearly result in an oversupply and suppressed SREC prices if the Board tried to do it.

However, reading the entire section together, including its requirement for the Board to "take any steps necessary to prevent the exceedance" of the cost caps, suggests the best interpretation may be to set the budget-based MW targets as described above, within the cost caps and in a manner that allows the RPS to be met; and to then, if it considers this helpful to the transition, express those budget-based MW targets as a share of the overall *renewable* energy requirements of paragraph 2. Our recommendations are made with this reading in mind.

9. *Measuring the cost cap and whether "headroom" should be banked and credited against future year costs?* The cost cap should be based on total dollars billed to retail customers for utility and energy supply services. This amount should be forecast based on a rolling average, and trued up annually for any deviation between forecast and actual. Net benefits actually received or enjoyed by ratepayers should be added to the cost cap, as discussed in our answer to question 10. Headroom should be credited through banking and, potentially through limited borrowing. See our part e. of our answer to staff question 11, below.

10. *Use of net ratepayer benefits in determining the cap.* We believe such costs can be used in a manner consistent with the statute, but we recommend the Board be careful to avoid double counting and counting of gross benefits rather than net benefits. For example, gross benefits, in excess of net benefits, are simply income transfers from one set of economic agents to another set. If ratepayers are the ones the income is being transferred from, it would be hard to defend such a policy as reducing the ratepayer costs specified by the statute as the basis for the RPS cost caps. Further, since the statute puts a limit on total ratepayer expenses, the Board should consider carefully limiting any net benefits it includes to those that benefit ratepayers directly, either in terms of lower out of pocket costs or in terms of other lower costs that they can expect to experience due to the RPS program. These should include the ratepayer benefits of avoided New Jersey population-based health, property and other economic damages prevented or reduced by renewable energy used in New Jersey and its effects on displacing pollution from fossil generation in the state and regional power markets.

    This legally and empirically conservative approach to adjusting the cost caps upward to account for net benefits should not be used in all other policy determinations, such as distribution system planning, evolving approaches to improving net metering, or other clean energy policies. Instead, for those, we recommend a broader, systematic analysis of clean energy costs and benefits be developed in the state's clean energy planning process, and used in managing, planning and evaluating its progress in achieving its clean energy goals, developing new RPS incentives and other clean energy policies. Once established and in operation, this process should also be used to most accurately identify the net costs of the RPS requirements, as part of an evolving clean energy system, to ratepayers.

11. *How to implement the cost caps.* As discussed above, for the solar transition and the state's clean energy goals to succeed, the BPU will need to actively manage the budget created by the cost caps, rather than merely monitoring it. In our view, managing the cost-caps will entail the following three steps:
    a. **Calculate the Class I RPS Budget**. The BPU will need to project future electricity sales to calculate the RPS Budget, using 9% or 7% as specified by the Act, and adding in any annual net ratepayer benefits recognized by the BPU as offsets to the statute's ratepayer cost caps.
    b. **Project total Class I annual costs for current and future years.** The BPU, in coordination with the state's Energy Master Planning Process, will need to estimate the costs of meeting the RPS target in each year, starting with the current EY19, as well as projecting those costs forward through the entire RPS period. Total estimated costs for each year should include:
        i. Compensation to legacy solar projects, which is the product of the number of SRECs purchased from legacy solar projects or other legacy SREC holders, multiplied by the SREC price in each year;
        ii. Initial and recurring annual compensation to transitional and successor program solar projects;
        iii. Initial and recurring annual expenditures for additional renewable energy required to meet the remaining Class 1 RPS goals, after accounting for the MWh provided by legacy, transition and successor program solar and offshore wind.
    c. **Ensure that current and future costs fit within the RPS budget**.

d. **Modify the mix of new RPS resources to be procured or incented each year** to achieve a mix that fits within the budget while meeting the RPS goals and supporting the state's other clean energy goals;

e. **Adjust the next year's available annual budget available**

   i. Rolling forward any unspent budget from previous years ("banking");

   ii. Borrowing short-term, highly predictable budget surpluses from near-term future years, after accounting for recurring and new costs needed in those years to meet the RPS goals ("limited borrowing");

   iii. Adding in any appropriate net ratepayer benefits from RPS resources that have already been deployed.

f. **Consider steps to further reduce RPS costs** beyond those currently under discussion in the solar transition straw proposal. For example, the BPU should consider policy changes to enable the procurement of RECs through long-term contracts, with a variety of credit-worthy counterparties, for new, fully additional renewable generation. Such a policy would reduce the costs of RECs, freeing up more of the RPS budget to use for more expensive but socially desirable resources, and allow for accurate projections of future REC costs.

g. **Integration of RPS planning with the State's Energy Master Plan** offers a pathway to continually evaluate and improve both the RPS and the EMP, while reducing costs to ratepayers and accelerating the state's 100% clean energy goals.

Clearly there will be trade-offs between the amount spent on new solar and the amount left to buy enough Class 1 RECs to meet the RPS goals. Further, by combining a new solar program, the cost caps, and an aggressive RPS mandate, the legislature clearly anticipated the Board managing these trade-offs in a way that achieves all the goals in the best way within the budget (as the straw proposal's principles appear to contemplate). We believe all these goals are possible, as discussed above. Therefore, we think the Board would be remiss in its duties and in meeting its various statutory requirements if it did reduce the overall RPS goals, due to exceeding the budget set by the statute. For this reason, we urge the Board to actively manage the budget to meet the RPS goals, and not to passively monitor it. And managing the budget means finding the best mix of more expensive in-state and less expensive out-of-state renewables that will meet the RPS goals, consistent with the State's many other important clean energy goals.

12. *Will solar be able transition to a true, incentive-free market? Should this be a program goal?* Yes. As solar costs continue to fall, long-term and the value proposition of products and services such as solar + storage or solar + smart energy management grow, we are confident that solar will increasingly be bought by customers for its value proposition alone, and will require lower and, in a growing number of applications, no additional incentives. The Successor program must be designed with this outcome in mind, to the extent feasible, as suggested by the CEA language cited in our answer to question 8 above.

13. *Other significant issues:* While we appreciate Staff's approach of proposing "SREC Transition Principles", some of the principles proposed in the straw proposal can be interpreted in ways that would conflict with our view of the requirements of the CEA. Because of the critical importance of these basic requirements, we recommend that principles 1, 3, 4 and 6 be clarified as follows:

Principle 1. “Maximum benefit to ratepayers at lowest cost” can be interpreted in many ways. The primary ratepayer consideration should be to meet the RPS goals and carry out the solar transition within the cost limits established by the legislature. Additional considerations include ensuring and increasing resilience, reliability and safety of electric service; supporting competition in clean energy and clean energy services to further lower costs and improve services, and improving utility programs and services that cannot be provided competitively to achieve the same ends. Special focus should be provided on ensuring efficient, safe and affordable clean energy services as well as increased job opportunities for chronically underserved communities. Any additional “benefits” for ratepayers should be considered in light of the cost-benefit principles discussed below.

Principle 3. “Ensure that prior investments retain value” is vague and subject to many interpretations. This could, for example, mean that SREC price levels should never fall from their current level, or that the all-in costs, including equity and debt capital, of each legacy solar project, should be recovered through SREC prices after the SREC program is closed. Or it could mean SREC prices should never fall to levels where SREC projects could not be liquidated even at some residual value. Or it could mean anything in between. As discussed below, we recommend the principle of compensating legacy SRECs with SREC price levels that are as high as feasible under the legislative cost limits, banked over time and with appropriate offsetting ratepayer benefits, after setting aside enough money to provide incentives for all new renewables needed to meet the interim and final RPS goals, including through continued solar development in New Jersey.

Principle 4. The key principle should be to meet the statute’s interim and 2030 RPS goals for renewable energy as a specific % of all energy sold and to set a course for meeting the Governor’s 100% clean energy 2050 goals.

Principle 6. “The implications of the cost caps” needs to be expressly combined with the commitment to meet the statute’s interim and 2030 renewable energy goals. In other words, even though it is allowed by the statute as a last resort, reducing the RPS goals should not be an option the BPU contemplates, plans for, or allows itself to be backed into (e.g., by allowing SREC prices for legacy solar projects to exceed levels that allow the RPS goals to be met within the statute’s cost limits).

Accordingly, we urge the staff to clarify and update these principles in a revised straw proposal provided before at the beginning of the stakeholder workgroup process in April.