Comments of NJCF, NRDC and NJSBC
regarding
NJ BPU
Request for Stakeholder Comments on Solar Successor Program

Docket Nos. QO19010068 and QO20020184 – In the Matter of a Solar Successor Incentive Program Pursuant to P.L. 2018, C.17

On February 28th, 2020, the BPU announced the Solar Successor Program Stakeholder Meeting 1, and invited stakeholders to respond in writing to twenty-three questions covering three topics regarding the Successor program. The New Jersey Conservation Foundation (NJCF), the Natural Resources Defense Council (NRDC) and the New Jersey Sustainable Business Council (NJSBC) respectfully offer the following answers to the questions in each topic.

Topic 1. Questions 1-7 are about Successor Program Incentive Design, and reference the three following basic types of incentive programs identified by Cadmus:

i) Tariff-Based Incentive: eligible projects would receive a total compensation based on the MWh produced, in which the incentive would fill the gap between other value streams and the total compensation.

ii) Market-Based RECs: eligible projects would create RECs, the value of which would be determined via competitive supply and demand, similar to the Legacy SREC program.

iii) Performance-Based Incentive: eligible projects would receive a fixed incentive value based on the MWh produced, with the value of the incentive set to reflect specific environmental attributes.

Questions:

1. Please describe the advantages and disadvantages of the three incentive program types identified above.

i. The first alternative would pay all eligible projects a predetermined price, based on the projected gap between (a) the cost of an efficient project of that particular type and (b) other revenue streams it is eligible to receive. There are two very different constructs, however, that could fit within this definition. The first would be an *absolute hedge* on total costs, and would adjust the total compensation to solar projects up or down to adjust for any change in other revenue streams. The second would be a *fixed payment* throughout the predefined term of the incentive payment. This fixed payment would not vary even if the other revenue streams increased or decreased over time.

Of these two, the fixed payment approach will have much better incentives for projects to accept and manage the risk of other revenue streams, such as potential changes in net metering buy-back rates, avoided demand charges, changes in federal tax credits, and customer pay-back hurdle levels. The absolute hedge, however, would dilute or erase the incentive solar developers and projects have to maximize these revenue streams or negotiate efficient risk-management terms in their contracts with customers, leading to an overall increase in the costs of these risks that are recovered from other electricity customers / ratepayers.

We strongly recommend the fixed payment approach, which would provide significant revenue assurance and stability, and should result in highly financeable projects and competitive debt costs, while creating much better incentives for developers and projects to anticipate and manage the risks identified above. And it would be much more efficient from a regulatory perspective than the absolute hedge, which would require continual complex and potentially contentious true-up proceedings.

ii. NJCF and NRDC have repeatedly identified the flaws of the market-based approach in numerous solar-transition comments over the least 18 months, so we will not repeat them at length here. The main problems are economic inefficiency, since SREC markets decouple the marginal cost of any project from the SREC price formation process; unfairness, since SREC markets pay one price to all projects, overcompensating less costly projects and project types, while undercompensating more costly ones; and extreme volatility that increases financing costs and creates continued demand for political interventions to stabilize the price by increasing demand relative to supply. These flaws are the reason the CEA requires the closing of the current SREC program and lays out the criteria cited above for a replacement successor program. It would be a grave error to attempt to use a similarly flawed market-based approach in the successor program.

iii. The third category, a so-called "performance-based incentive" would establish a value for specific environmental attributes. This approach is less likely to be beneficial, for several reasons. First, the specific challenge facing new solar in New Jersey is to recover its costs while achieving further cost recovery and a growing share of the clean energy market. An incentive program designed to do exactly that efficiently is likely to be easier to develop and more effective than one designed to put a price on vaguely specified environmental attributes. And specific environmental attributes, such as actual CO2 displaced by a particular MWH of solar energy, will prove harder to measure and much more dynamic as higher levels of renewable energy are generated and as renewable energy starts to displace other renewables, instead of displacing fossil fuels, at times of high sunshine and wind.

2. How would you expect the incentive value (and the cost to ratepayers) to change based on the incentive program type?

We believe the fixed payment version of alternative (i) would have the smallest impact on ratepayers, due to low financing costs due to its long term, fixed value, and to better incentives for each developer and project to anticipate and manage risks around other variable revenue streams.

3. Should the Board establish a differentiated incentive (i.e. different incentives for

different project types), as was done for the Transition Incentive program? If yes, what should these different project types be?

Yes. We recommend the same basic categories used in the Transition program as a good starting place, with potential refinement through a stakeholder process.

4. How should the Board set the value of the incentive: via administrative modeling, a competitive solicitation, or an on-going market? What are the advantages and disadvantages of these three mechanisms?

An ongoing SREC or environmental attribute market should not be used for the reasons given in our answer to Question 1. The choice between administrative modeling and competitive solicitation depends on several factors.

- First, does a specific type of solar have a fairly uniform cost structure, or are costs highly project specific? If it has a fairly uniform cost structure, a competitive solicitation could be effective at eliciting that information. But with very diverse, project-specific costs, modeling with stakeholder input and feedback during the development of the model is likely to do a better job of refining the category and of establishing cost estimates that are best suited to achieving the goals of the statute and the BPU's solar transition goals.
- Second, can the competitive solicitation itself be designed to attract efficient and realistic bids, while avoiding the "winner's curse" of being won by bids that are unrealistically and infeasibly low?

We recommend the BPU explore competitive solicitation approaches through the stakeholder process before deciding between the best of those approaches and administrative modeling. In addition, as noted below, we believe competitive solicitation with pay-as-bid PPAs for winning projects may be both feasible and preferable for larger, grid-supply projects as part of the successor program.

5. How should the Board establish and periodically revise the maximum incentive payment caps described in the Clean Energy Act?

Through updated administrative modeling and / or competitive solicitations. As a first indicator, the costs of solar energy projects are relatively transparent and are monitored and reported on by a variety of experts, and any significant reduction in reported costs from credible sources should trigger a deeper examination of costs in New Jersey and the potential for reducing the incentive payment caps.

6. What is the preferred incentive qualification life (10 vs. 15 years) based on typical project financing?

Longer term revenue assurance typically results in lower cost debt, so we recommend 15 years.

7. The Clean Energy Act requires that the Board "encourage and facilitate market-based

> cost recovery through long-term contracts and energy market sales." Please provide your assessment of various market-based cost recovery mechanisms, and their applicability to each of the three incentive program types developed by Cadmus.

We read this requirement as calling for the BPU to take steps to enhance the value that solar projects can create for customers, and to design the Successor program to incent solar developers to recover more of their costs by charging customers a competitive and reasonable amount for creating that value.

For example, solar projects for customers without demand charges (e.g., residential customers) create customer value and willingness to pay for solar based on avoided retail energy purchases, plus any net-metering-based payments for net exports back to the distribution system. Adding storage and energy management capabilities to residential solar can allow more power to be shifted to behind the meter use instead of export, which can create additional customer value under time-of-use rates or in jurisdictions where load-serving entities can avoid more expensive wholesale power purchases or generation at specific times (such as when those wholesale power costs are highest, e.g, after sundown or on cloudy days). Accordingly, BPU could encourage more revenue for solar projects from such value propositions by exploring TOU rates and steps to allow energy storage or distributed energy production to directly reduce the wholesale energy purchase or generation costs of each load-serving-entity.

Customers with demand charges can benefit from, and are willing to pay for, avoiding or reducing those demand charges, consistent with avoiding or reducing the maximum amount of power they need to use at any given time. Adding storage and energy management capabilities to solar projects serving larger customers can support greater and more permanent demand reductions, creating greater customer value streams and a higher willingness to pay for them. Accordingly, BPU could encourage and support more revenue opportunities for solar projects by exploring ways to use solar plus storage and energy management technologies to reduce demand and demand charges for solar customers.

As discussed above, such increased value propositions for customers would fit well with the "fixed tariff" approach (i) above, and would be frustrated and made largely irrelevant under the "absolute hedge" version of approach (i). The SREC market-based approach could tend to focus solar developer and project owner efforts on increasing the SACP and solar carve out, rather than increasing the customer value proposition; while the environmental attribute approach seems largely unconnected to customer value, other than those related to any air emissions actually displaced or reduced by the solar project.

Topic 2. Questions 8 – 15 address the statutory requirement for the BPU to set MW targets for grid connected solar and solar connected to distribution systems, including residential and small commercial rooftop systems, community solar systems and large scale behind the meter systems, and to periodically modify as needed based on the cost, feasibility, or social impacts of different types of projects.

Questions:

8. What MW target project categories should be established?

See our answer to question 3 above.

9. How should the Board set the capacity for each MW target, in compliance with the incentive cap and cost cap requirements? Please consider: 1) how the Board should set the overall capacity to be made available on an annual basis for the Solar Successor Program; and 2) the relative breakdown of the total annual capacity between MW target project categories.

We recommend a budget-based approach, whereby the BPU regularly updates its RPS cost-cap "headroom" analysis to account for any changes in current and projected costs, and projects an amount of projected future spending on Successor program incentives that will not exceed the cost-cap "headroom" in any future year. This multi-year perspective is critical since each year's new "tranche" of eligible projects will collect incentive payments during the entire payment period of those incentives. The amount of headroom-preserving spending for each upcoming year's new tranche of projects creates a budget for that tranche, should then be allocated across the various types of capacity eligible for incentives. This process will assure that the cost-cap is not exceeded.

In terms of choosing the actual mix of project types to be offered incentives within this budget each year, that will require judgement calls on the part of the BPU regarding other factors that could provide reasons for reducing total MW by increasing the MW of a certain type of project that costs more than others.

10. For reference, the breakdown of installed capacity by solar installation type as of January 2020 is as follows:

Residential	11. 30%
Non-Residential < = 100 kW	12. 4%
Non-Residential > 100 to < 1000 kW	13. 24%
Non-Residential > = 1000 kW	14. 21%
Grid Supply	15. 21%

Source: https://www.njcleanenergy.com/renewable-energy/project-activity-reports/project- activity-reports

11. Should the historical breakdown of actual MW installations serve as the basis for future targets?

These current percentages are a starting point for the kind of budget-based analysis and allocation, discussed above. Adjustments in both the total quantity and the quantity of each solar type may be needed to keep the Successor program amounts within each new tranche's budget based on BPU's judgement, also discussed above. The 2020 numbers should not, however, be used without checking and adjusting them, if necessary, through the budget-based process described above.

12. How should the Board administer these MW targets? Should projects be allowed to participate on a first-come, first-served basis?

We do not at this time have a specific recommendation on this question, but recommend the BPU conduct an evaluation, using both its consultants and the stakeholder process, of best-practices in related programs, including both competitive procurement programs and declining block tariff programs, to identify the most appropriate approaches to administering this aspect of the successor program.

13. What measure should the Board implement to prevent "queue sitting"? Please include in your response a discussion of a) maturity requirements, b) filing fees, and c) alternative suggestions.

We do not at this time have a specific recommendation on this question, but recommend the BPU conduct an evaluation, using both its consultants and the stakeholder process, of best-practices in related programs, including both competitive procurement programs and declining block tariff programs, to identify the most appropriate approaches to administering this aspect of the successor program.

14. Should excess annual capacity be reallocated if not used (e.g. if a project drops out of the pipeline)?

The answer to this depends in part on the approach or approaches BPU selects for addressing questions 12 and 13 above. For example, if there is a queue of projects and one drops out, the next in line could step up.

15. Should projects located in municipal utilities that do not pay into the RPS be eligible to receive Successor Program incentives?

Such a result would seem unfair to the electric customers who are not customers of municipal utilities and who would be paying more for the successor program than the municipal customers. Perhaps a fairer approach would be a comparability standard, whereby solar projects located in municipal utility service territories could receive incentives, if the municipal utilities elect to pay a comparable amount into the solar program. However, at that point, any affected municipal utility might prefer just to offer its own solar program.

16. How can the State most efficiently progress towards the goals set in the Energy Master Plan, while balancing ratepayer costs for solar development in- and out-of-state?

This is an important question not just for solar, but also for wind, storage and flexible load, and even clean firm generation. Our recommendation is that the BPU explore in a concerted way a new approach to creating incentives for the most efficient mix of these resources, that would also support compliance with a modified or augmented demand obligation that goes beyond the current RPS. One concept for such an augmented demand obligation program is the idea of dynamic clean electricity standard using dynamic clean energy credits. Unlike RECs and SRECs, such DCECs would be awarded based on the actual reductions in CO2 emissions from the marginal (last to be dispatched) resource that is displaced in each dispatch interval by an eligible clean energy resource. This approach would reward the most DCECs to clean energy resources that displace coal fired power, medium amounts of DCECs to clean resources than displace gas-fired power, and no DCECs to clean resources that simply displace (i.e., curtail) other clean resources. Instead, this approach would create strong incentives to store or shift the demand for clean energy that would otherwise be curtailed, helping create the mix and location of a wide variety of clean energy resources that will most rapidly reduce GHG emissions. Allowing a share of a clean electricity standard's demand obligation on LSEs to be met by DCECs from out of state resources, and another share to be met only with in-state resources, has the potential to support significant, efficient progress towards the goals set in the EMP, at a low overall cost to electric customers / ratepayers. Finally, DCECs could be priced in a variety of ways, including under PPAs and declining block incentive tariffs, to avoid or limit the volatility and other risks of the current SREC market.

Topic 3. Grid supply Solar. In the Legacy SREC program, grid supply project could be eligible for SRECs if they met the requirements defined at N.J.A.C. 14:8-2.4. These projects are known as subsection (t) and subsection (r) projects.

Questions:

17. Should the Board maintain the current subsection (t) and subsection (r) processes for determining incentive eligibility for grid supply projects?
   - If yes, what conditions should be maintained?
   - If no, how should the Board treat grid supply projects?

Yes. The BPU should continue to determine the eligibility of grid scale projects to receive successor program incentives under subsection (r). In particular, criterion (b) in subsection (r) is important to preserve as a screen against awarding incentives to projects that would significantly impact the preservation of open space in the state. However, criterion (a) will be irrelevant under a Successor Program that does not use the SREC market, and criterion (c) may be irrelevant if the project is consistent with the EMP and fits within the RPS cost-cap budget. Similarly, criterion (d) may be irrelevant under any appropriate interconnection requirements.

18. Should the Board set a dedicated incentive value for grid supply projects? If yes, how can the Board best determine the appropriate incentive value (i.e. incentive gap

modeling vs. bid process)?

Grid supply projects have a long track record of successfully bidding into competitive procurement programs in a number of states and throughout the world. We recommend that the BPU seriously consider competitive bidding for grid supply, with pay-as-bid PPAs awarded to the bidders with the lowest cost per MW, up to the number of projects that provide the maximum number of MWs allowed under the budget-based allocation approach recommended in our answer to Question 9 above. This pay-as-bid procurement approach is likely to better accommodate differences in project costs than a single incentive price for all grid supply projects. Such different project costs could result from limited access to open space or farmland, as provided for under subsection (r) and (t) and discussed below. This approach could also provide the most efficient solution to Question 19, namely that the queue would be established by bidding, and each project's place in the queue would be determined by its price-based ranking.

19. Should the Board establish a maximum system size to be eligible for a Successor Incentive? If not, how should economies of scale and the lower incentive gap be accounted for solar electric generation facilities over 20 MW?

To reduce overall costs, the BPU should avoid penalizing or limiting larger projects with the best scale economies, provided they do not involve converting farmland and open lands such as woodlands, wetlands or critical wildlife habitat to energy production. Instead, BPU should attract and reward the large-scale projects that have the best economics through a competitive-bid / PPA approach for larger grid supply projects, as recommended in our answer to Question 18.

20. What is the best means to motivate investment in rooftop grid supply solar facilities where insufficient electricity loads preclude net metering and the wholesale value of electricity generated increases the incentive gap relative to rooftop net metered projects?

Large rooftops such as these are a very difficult market for solar development, due to a variety of factors, such as different value propositions for the landlord and tenant, insurance limitations, and rooftop age and warranty conditions, in addition to those mentioned in the question. We recommend the BPU explore this question with a representative group of New Jersey large rooftop owners and facility managers.

Topic 4. Solar Siting.

The 2019 Energy Master Plan states that, "in order to enhance smart siting of solar, the state should better define areas that are considered marginalized, such that they have constrained economic or social value." This includes a commitment that "NJDEP and NJBPU will coordinate land use policy for solar siting with the New Jersey Department of Agriculture to identify sites that could be used to expand New Jersey's commitment to renewable energy while still protecting the state's farmland and open spaces." (EMP Goal

2.1.8)

Questions:

21. How should the Successor Program incentive structure be designed to address the state policy preference for solar located on rooftops, landfills and brownfields versus open space and farmland?

Consistent with N.J.S.A 48:3-87(r), by not awarding incentives to solar projects that convert farmland, woodland, wetland, critical wild-life habitat and other such high-value open spaces to energy production, and instead by concentrating those incentives on rooftops, landfills, brownfields, and other marginalized or degraded land.

22. What land use restrictions and limitations should apply to the Successor program incentive to reflect the siting of solar projects in New Jersey? Please include a specific discussion of solar on farmland and open space, consistent with all applicable New Jersey statutes and regulations.

The Successor program should not provide incentives to site solar projects on farmland or open space in New Jersey. Instead, the Successor program should, like the Community Solar Pilot Program, focus its incentives on projects located on rooftops, parking lots/decks, areas of historic fill, brownfields and landfills and similar disturbed lands.

Projects that would have an adverse impact on open space, or on farmlands beyond those grandfathered under the Solar Act of 2012, should not be eligible for incentives. This ineligibility for incentives should apply to projects that would adversely impact state, county, municipal or non-profit Green Acres open lands, as defined in N.J.A.C. 14:8-9.2 or on land owned by NJ DEP, except for projects entirely located on parking lots or rooftops of structures on the site. Any concern that this ineligibility creates a cost or other impediment to achieving the EMP goals should be evaluated through the actual operation of the Successor Program and through the exploration of alternatives through the IEP/EMP cycle, before any changes to such projects' eligibility are considered legislatively or administratively.

23. Aside from the various types of net metered projects and grandfathering a defined set of projects on farmland, the Solar Act of 2012 limited eligibility for SRECs to solar electric generation facilities which demonstrated no adverse impact on open space or those located on properly closed sanitary landfills and brownfields as defined in the Spill Compensation and Control Act. Should the criteria for Successor Program incentives retain these limitations as contained in the statute or be refined to broaden eligibility beyond the footprint of a landfill cap or limits of the brownfield site?

The Successor Program should retain these limitations. Any concern that they will impede achieving the EMP goals should be evaluated through the operation of the Successor program and the exploration of alternatives through the IEP/EMP cycle, prior to any legislative or administrative changes being considered.