Submitted Via Email

September 8, 2020

State of New Jersey
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey 08625-0350

RE: Successor Program Capstone Report, Docket No. QO20020184

Dear Secretary Camacho-Welch:

Please find enclosed the joint comments of New Jersey Conservation Foundation and the Natural Resources Defense Council in the above referenced matter. We appreciate the opportunity to provide input as the state works towards finalizing New Jersey's solar successor program.

We also understand that a separate proceeding is planned to address remaining critical cost cap and legacy solar cost issues that are not directly addressed in the Successor Program design questions raised here. We look forward to the opportunity to comment on those issues as well, which will greatly impact achieving solar targets in the Successor Program as set forth in the Energy Master Plan.

Sincerely,

Eric Miller, Natural Resources Defense Council

Barbara Blumenthal, New Jersey Conservation Foundation

Topic 1: Recommended Incentive Structure Design

Based on stakeholder engagement to date, Cadmus presents three incentive "types" in the draft Capstone Report that could be used to inform the design of the Successor Program (see section 3.3, p. 16 – 25):

- Total Compensation: similar to a contract-for-differences model, a total compensation incentive structure calculates all the revenue streams generated by a representative project to arrive at a complementary performance-based incentive amount that may change over time as revenues change to achieve an administratively determined investment target. The incentive value is added onto these revenues to reach a total fixed compensation value.

- Fixed Incentive: a fixed incentive structure is one in which the value of the performance- based incentive is fixed over time, similar to the current Transition Incentive Program.

- Market-Based RECs with Floor: a market-based REC is an incentive that varies over time above a pre-defined floor price, based on the supply of RECs produced by eligible solar projects, and the demand set by the RPS

1) The draft Capstone Report recommends the implementation of a bifurcated incentive structure, with a competitive solicitation for utility-scale projects and fixed, administratively- set incentives for smaller projects.

    a. Do you agree with this recommendation? Why or why not?

Yes, with provisos listed below in (b) i . We think this approach is best suited to result in the lowest overall cost for the Successor program, while also providing adequate protection for open space, farmland, and natural environments. This approach is also consistent with specific successor program guidance of the Clean Energy Act ("CEA").

    b. If you agree with this recommendation, how should NJBPU divide market segments between those projects eligible for the competitive solicitation and those projects eligible to receive the administratively set incentives?

        i. Do you view project size as the appropriate means of differentiating between competitive solicitations and administratively-set incentives? If so, please identify what NJBPU should consider to be the size limit between a utility-scale and small scale project.

We recommend that the dividing line between competitive solicitation and administratively set incentives not be made based on project size, but on whether the project is located behind the meter or in front of it. Projects that are in front of the meter depend entirely on revenues from selling their energy and capacity bilaterally or into wholesale markets, and thus - to the extent market revenues are not sufficient to support their investment -- need some additional incentive-based revenue. By contrast, behind-the-meter resources, including community solar projects, receive revenues in the form of customer payments that are voluntarily agreed to by customers to avoid exposure to retail energy rates and demand charges. With net metering, the avoided retail purchases extend beyond those avoided by consuming the resource's solar electricity directly, and also include savings due to crediting the resource's net monthly kilowatt-hour exports against the customer's bill at the retail energy rate. The net amount of compensation available through customer payments for these benefits may exceed that available through wholesale market sales, particularly because retail electricity rates are typically higher than wholesale market prices. Accordingly, compensating behind-the-meter and in front of the meter large-scale solar projects at the same level is likely to over-compensate behind-the-meter projects or under-compensate those that are able to charge customers for behind-the-meter benefits.

ii. If project size is used to differentiate incentive-types, how should NJBPU develop a competitive solicitation for utility scale projects that takes into account the different revenues that net metered projects earn compared to those that sell at wholesale?

iii. Alternatively, should all net metered projects rely on administratively-set incentives instead?

Some net-metered projects may currently, or in the foreseeable future, be able to recover their costs adequately simply through the customer payments made for the behind-the-meter benefits (e.g., avoided energy and demand charges under the applicable retail tariffs), and therefore would not need additional incentives in a successor program. However, to the extent this is not possible, we recommend administratively-set incentives for behind-the-meter solar projects that are unable to achieve financial viability without them.

iv. If you recommend a different option for establishing criteria to distinguish projects that qualify for competitive solicitations versus fixed incentives, please elaborate on your recommendation.

v. How should projects that meet the requirements of the Solar Act subsection (t) (i.e., grid-supply projects located on landfills and brownfields) be treated?

We recommend that the competitive solicitation process for large-scale projects require project bids to identify their location and whether or not they will be located on landfills and brownfields. During the bid evaluation, it will then be possible to determine whether higher incentive prices are needed for certain locations (such as in-state versus out-of-state or in-state on landfills and brownfields). If so, then the successor program could award higher incentive levels by these categories, until it had subscribed an amount of solar capacity it considers adequate in each category, considering any statutory requirements or other policy guidance, including DEP's preferred categories for solar siting and the CEA's RPS cost-caps.[1] See the discussion below about cost-caps in response to question 10.

c. If you disagree with the concept of a bifurcated competitive solicitation and fixed, administratively-set incentive approach, what would you suggest as an alternative incentive structure? Please be as specific as possible.

2) If NJBPU were to implement administratively-set incentives:

a. How often should the incentive value be re-evaluated and potentially reset? Please comment on the mechanism by which NJBPU should consider modeling and analysis to inform future deliberations regarding incentive values.

We suggest re-evaluating incentive values every three years, consistent with the timing of the

[1] *See* NJ DEP, *Solar Siting Analysis Update* (Dec. 2017), *available at*: https://www.state.nj.us/dep/aqes/SSAFINAL.pdf

Energy Master Plan ("EMP") cycle and the integrated energy plan analysis used to develop, modify and support the EMP. Updating the need for and the level of solar incentive values and capacity targets should be based on both the evolving EMP and an updated analysis of recent solar costs and the volume of responses to existing incentive levels. Excess demand for solar incentives in a category of solar projects would be an indicator that the existing incentive levels are higher than needed, while inadequate supply of a category of new solar projects would be an indicator that existing incentive levels are not high enough, or are too risky, to attract solar investment.

b. Should NJBPU differentiate the incentive value (similar to the TREC factors)? If so, on what basis? Please discuss whether NJBPU should differentiate based on the following: (i) customer classes; (ii) installation type / project location; (iii) EDC service territory; (iv) project size; or (v) other.

Incentive values should vary across project type, recognizing that significant differences exist in the underlying costs of solar projects as well as in their sources and amounts of revenue.

c. How is an administratively-set incentive consistent with NJBPU's goal for continually reducing the cost of solar development for ratepayers, in line with the reductions in the cost of solar development?

The process for updating the need for and the level of incentives outlined in our answer to question 2(a) should support and facilitate achieving this goal.

d. In the draft Capstone Report, Cadmus used a 15-year Qualification Life (i.e., incentive term) as the base case, with the exception of residential net metered direct-owned projects, for which the incentive term was set at 10 years based on project payback period. Please comment on these respective proposals regarding length of qualification life, including what changes you would suggest, if any, and why.

3) If NJBPU were to implement incentives based on a competitive solicitation:

a. How should the competitive solicitation be designed? What evaluation criteria should NJBPU implement in administering the solicitation? Should project selection be based exclusively on price (i.e., value of the incentive), or should it include consideration of other criteria (and if so, which ones)?

We recommend that the competitive solicitation for large, in front of the meter projects explicitly invite bids for, and restrict them to, a minimum level of fixed incentive payments over time which, if less than or equal to the level of incentive payments awarded to the project under the solicitation, the project would be contractually bound to develop and operate its project and transfer ownership of all environmental attributes, such as Class 1 RECs, future SRECs, and Clean Electricity Credits under a state or federal clean electricity standard, to an agent or entity designated by the NJBPU. Bidding projects would also have to post bidding and performance bonds sufficient to establish their bona-fides and to ensure their contractual performance in the event they are selected.

Under our recommendation, project selection would be based on bid price, with all bids ranked by incentive price bid and accepting those with incentives at or below the level that is compatible with the headroom that is dynamically available (i.e., available in each year going forward under the ongoing obligations of existing and new projects needed to meet the RPS) under the RPS cost caps.

We recommend emphatically against using points awarded for preferable sites, project sponsor credit ratings, and other variables as evaluation criteria. Instead, all of these requirements should be established clearly as "bright line" requirements in the RFP and pro-forma contract, and only projects that meet them should be eligible for being awarded an incentive. There should be no trade-offs established or allowed for sub-standard or risky projects that, for that reason, are able to offer a price that is too good to be true, or cheap enough to warrant the damage to ratepayers, the reputation and credibility of the state and the solar industry, or the environment that they could create.

We offer specific recommendations for bright-line siting requirements in additional comments, at the end of these comments.

b. Cadmus studied incentive structures for the environmental attributes of a given project (i.e., unbundled the environmental attribute, with projects remaining merchant on energy and capacity values). Please discuss project finance-ability of this incentive structure, as opposed to a bundled incentive structure, addressing the implications to price and risk to ratepayers.

There is a substantial history of large renewable energy projects getting financed on the basis of volatile REC revenues and wholesale market revenues. Further, wholesale energy and capacity market hedges are available in the broker-based market for such projects that find market revenues too volatile on a pure merchant basis. Thus, there already are market alternatives that should be preferable, less costly, and more consistent with the CEA's specific guidance regarding the goals of a successor SREC program to the NJBPU, than simply assigning all of these risks in a non-bypassable fashion to ratepayers. Under the competitive procurement process recommended above, individual projects will need to balance the desire to have a higher incentive payment serve as an additional hedge against market revenue risk, and their desire to bid low enough to win an incentive contract in the competitive procurement process. Generally, bids should be lower for those projects most capable of managing their wholesale market risks, and those are the types of projects that the NJBPU should be most interested in encouraging under the CEA guidance. Selecting such projects will minimize both the price and risk impacts on ratepayers, and allow the largest volume of new solar projects under the CEA's cost caps, while staying true to New Jersey's and the NJBPU's commitment to protect open spaces, farmland and natural environments.

c. How would NJBPU set the incentive value using a competitive solicitation? In particular, please discuss the pros and cons of a pay-as-bid system or a single-clearing price system.

For highly homogenous products and commodities, a single-price auction is generally more efficient than a pay-as-bid auction. However, in auctions for distinct items, it is generally more efficient to have separate prices for each item or combination of items (determined either through separate auctions or through "package bidding"), due to the substantial difference in both cost and customer value of the various offerings.

In competitive procurement of specific projects, however, multiple projects, each with its own unique cost and capabilities, are typically evaluated in order to find the combination of projects that create the most value. Because each project has different costs, and may provide more or less value, competitive procurement of projects is almost always carried out through a solicitation that ranks bids by price and procures the requisite number of projects that collectively offer the lowest cost, each being paid at their bid level.

Centralized REC markets and capacity markets have typically focused on the homogenous, commodity-like character of RECs and megawatts of UCAP, and thus have often used a single-price approach, though there are clear exceptions (e.g., the bilateral tolling agreements entered into through bundled energy and capacity procurement in some markets, California's RA product, etc.).

In the proposed incentive-only approach for large scale, in front of the meter solar projects, arguments could be made for either approach. However, we recommend a pay-as-bid approach, because of the fact that bids from different projects, such as in-state or out-of-state, eligible for subsection (t) consideration and potentially in areas with higher or lower real-estate and interconnection costs within New Jersey, should be expected to have different costs. With sufficient competitive pressure to keep bids low, we anticipate that a single price procurement auction would end up compensating lower cost bidders at levels above those that would obtain under a pay-as-bid pricing rule. Accordingly, we anticipate that a pay-as-bid approach to the lowest cost bids acceptable under the budget-based allocation approach will result in the lowest cost for New Jersey customers and ratepayers.

d. Should NJBPU implement a minimum and/or maximum bid value in order to prevent overly aggressive or overly high bids?

Neither should be needed, however, of the two alternatives, a bidding cap would be less harmful. A floor is sometimes thought to be useful in preventing a "winner's curse," which refers to a situation where the winning bidder bids too low by being overly optimistic about their costs and the return they actually need to finance their project. However, the winner's curse can typically be avoided with adequate bidding and completion bonding requirements to weed out unscrupulous or speculative bidders. A bidding floor that is low enough to make any difference in a well-designed competitive procurement process will simply prevent the most competitive, low cost, and efficient projects from winning, and force ratepayers to pay higher costs for less efficient developers. This result should be avoided.

A bidding cap may be deemed useful by some if there is inadequate participation in a bidding process, but the logic is flawed. If a bidding process only attracts bids above the level at which competitive project developers can and are developing projects, the solution is to cancel the procurement and design a more transparent, dependable and trustworthy process. A better solution is to avoid this problem with a well developed, professionally managed procurement process and adequate assurances of stability in the awarded incentive payments over a sufficient lifetime. Given the amount of active solar development in the state and region, it would be very unlikely for a well-designed competitive procurement process offering a long-term, bid-based incentive payment not to attract substantial competitive participation and aggressive bids. Further, by using the budget-based capacity targets recommended by NJCF in February 22, 2019 comments on the Transition Staff Straw Proposal (Question 7), the procurement process would have a default "off ramp" in the event that bids are, for whatever reason, simply too high.

e. How often should NJBPU hold solicitations? How can NJBPU mitigate the risk of "stop and start" development cycles due to the nature of punctual solicitations? For example, should NJBPU consider implementing an "always on" incentive program in the context of a competitive solicitation? How would such an incentive be implemented?

f. Should NJBPU account for differences in project cost for different project types (e.g., project type or site, in-state vs. out-of-state)? If so, how?

The NJBPU should definitely take advantage of lower cost bids to ensure that it can achieve the RPS targets within the statutory cost caps for Class I renewable resources, other than offshore wind, used to meet the RPS requirement. We continue to recommend the budget-based approach to filling the RPS requirement proposed by NJCF in its February 22, 2019 comments, which uses enough of the lowest available compliance opportunities first to ensure that filling the rest of the RPS requirement with higher cost alternatives does not result in exceeding the cost headroom under the cost caps in subsequent years. Lower cost tranches of procured solar should be treated in this same, "lowest-cost-first when needed" manner.

g. In the draft Capstone Report, Cadmus used a 15-year Qualification Life (i.e., incentive term) as the base case. Is this the appropriate term for incentives determined via a competitive solicitation?

h. New Jersey's solar incentive programs have historically been delivered via a program established by NJBPU. Should NJBPU consider instead delivering the incentives through project-specific contracts with the EDCs? Would this approach reduce financing costs for developers? Please discuss the pros and cons of both approaches, including the potential benefits of a contract filed with the Federal Energy Regulatory Commission and imputed debt considerations.

We recommend the BPU explore options that would avoid encumbering the EDC balance sheets with the long-term contractual obligations associated with the large-scale solar procurement process discussed above. EDCs are likely to face substantial credit requirements in future years associated with resources that cannot be financed through other means than assured collection through EDC rates, and it would be a good idea to conserve their natural monopoly cost structure and credit worthiness for such investments. We think it is possible that the large scale procurement costs could be allocated more directly to BGS suppliers, potentially in much the same way that OREC costs currently are, and suggest the BPU and parties explore and develop such alternatives instead of simply tagging the EDCs with the costs of competitive clean energy contracts.

In terms of jurisdictional considerations, we do not see substantial benefits to an EDC contract for environmental attributes, such as we recommend, since the sale of environmental attributes, with no exchange of energy or capacity for resale, would not be FERC jurisdictional in any event.

4) How can NJBPU prevent queue siting or speculative project bids? In other words, what maturity requirements should NJBPU implement? Please consider, for example, minimum bidding requirements, escrow payments, etc. Should NJBPU require different maturity requirements for projects entering the competitive solicitation process versus the administratively-set incentive levels?

We recommend minimum bidder qualifications, and both bidding and performance bonding or escrow requirements to establish bidder bona-fides and create a strong disincentive to bid speculatively or to fail to devote adequate resources and experience to project development and completion. Part of any performance bonding or escrow requirement is for there to be realistic and reasonable, but firm, commercial operation deadlines that must be met for the escrow or bond to be returned.

5) The draft Capstone Report recommends that NJBPU maintain flexibility in program design, in order to respond to changing market circumstances and enable the integration of emerging technologies and new solar business models.

a. Generally, how can this flexibility be incorporated into the design of the

Successor Program?

We recommend the incentive levels and any forward looking capacity targets in the Successor Program be updated every three years, concurrent with the EMP and its associated integrated energy planning process, in light of new information on technology costs, availability, performance, and evolving understanding of the least-cost, best-fit approach to achieving the state's local and regional clean energy and decarbonization goals. Changes in cost of solar and related technologies will factor directly into the updating of incentive values and program details discussed in response to Question 2 (a) above.

b. How should changes in the federal Investment Tax Credit or carbon-pricing policies be incorporated into future incentive level resets?

Periodic re-evaluation of the incentives levels will address the impact of known changes in Investment Tax Credits, or of enacted carbon price policies on expected revenue. Changes in carbon pricing policies would likely impact expected revenues for solar projects in the wholesale energy and capacity markets, and would therefore be reflected in their bid levels. Existing large scale projects with previously established incentives would receive the higher wholesale market prices as well, and thus would have no need for any increase in their incentives to somehow capture the benefits of a carbon price. In a competitive procurement process, incentive levels will be determined by bids, and thus do not need to be administratively adjusted for, or in response to, changes in carbon pricing. To the extent behind-the-meter projects offer higher customer value, e.g., due to helping customers avoid higher cost competitive energy sold by their third-party supplier or BGS provider, new projects should similarly be able to negotiate higher solar payments from customers in return for the higher value received (or, in the case of directly-owned projects, capture that higher value directly). Existing BTM projects will already be made whole, including the return they locked in through their pricing offers and contracts with customers, and should not be awarded additional windfalls above the returns they agreed to, in the event a higher carbon price is imposed on fossil generators.

c. How should NJBPU account for potential changes to the PJM and FERC regulatory structures and capacity markets?

A major question in the large-scale solar procurement process will be whether the MOPR or future versions or alternatives of it actually have the effect of disallowing large scale solar that receives incentive payments under the Successor Program from clearing in the RPM market. If so, and if New Jersey had found it advisable and feasible to use an FRR alternative to avoid the double payments that would result from the MOPR, the RFP and procurement process could be adjusted to invite qualifying solar facilities to submit bids for incentives that would constitute payment for both UCAP and environmental attributes, either jointly delivered or severable. Such bids would be able to identify whether, given the risk of the MOPR to a wide variety of such projects, there would be strategic value to clean energy projects to bid at levels for combined incentives and UCAP that would avoid the downside of either suppressed capacity prices, or unavailable incentive payments, or both in a world with continued interference in state clean energy goals and programs by FERC-mandated measures in PJM's tariff.

More generally, even if the MOPR were to disappear or transform into a benign bidding rule, variability in FERC-jurisdictional capacity and energy prices are virtually certain to occur. To the extent large-scale project developers seek to hedge such risks in their bids for incentive payments in New Jersey's Successor Program, the competitive bidding and bid evaluation processes should be able to process the bids efficiently without any change in bid evaluation or accounting. Similarly, the budget-based capacity targets we recommend would ensure that any such bids would continue to be evaluated and accepted in a manner that is most consistent with the state's commitment to decarbonization and clean energy deployment, while complying with the statutory RPS cost caps.

6) The draft Capstone Report includes a SAM case for out-of-state utility-scale solar. Should NJBPU provide incentives to out-of-state utility solar through the Successor Program? If so, how, and under what conditions?

Yes, as discussed extensively above. We discuss specific deliverability considerations below.

a. The Energy Master Plan found that out-of-state utility scale resources deliverable to New Jersey are part of the least-cost path to reaching 100% clean energy. Do you agree or disagree that such projects should be eligible to participate in New Jersey's solar program?

b. Please address any commerce clause or other legal issues associated with restricting the ability of out-of-state utility-scale projects to compete in the competitive solicitation.

c. Should NJBPU require that such projects respect transmission limits into New Jersey? If so, how should such a requirement be designed?

d. Should NJBPU require that such projects sell their energy into New Jersey (i.e., deliver into a New Jersey EDC service territory)? If so, how should such a requirement be designed?

Questions 6 (a-d) raise a variety of issues related to the deliverability of solar energy from outside of New Jersey into New Jersey. It is not clear to us how the aspects of deliverability the questions raise relate to the specific meaning of deliverability under PJM's tariff and implicit in the security-constrained, economic dispatch (SCED) used to manage generator output in its energy market. In attempting to answer these questions, we will start by framing them in terms of our understanding of deliverability in PJM.

Deliverability under the PJM tariff has two distinct meanings. The first is called "load deliverability" and results in the locational generation requirements of both the RPM and FRR approaches to meeting PJM's resource adequacy requirement (RA). See PJM Manual 14B, C.2. The only reason this type of deliverability might be relevant to the RPS requirement is if the BPU determines to bundle together the purchase UCAP, for the purpose of complying with PJM's resource adequacy requirement, with the purchase of environmental attributes, for the purpose of complying with the state's RPS requirements. Such "bundled" procurement should, in our view, be explored through the current RA proceeding, and not established through the Successor program.

The second meaning of deliverability in the PJM tariff is "generator deliverability." See PJM Manual 14B, C.3. This meaning of deliverability does not mean that the output of a specific generator can be physically delivered to a specific geographic point in PJM. In fact, such physical deliverability is not possible to arrange or ensure in PJM's energy market. Instead, as Manual 14B explains,

> "Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if Capacity Resources are available and called on, their ability to provide energy to the system will not be limited by the dispatch of other certified Capacity Resources. This test does not guarantee that a given resource will be chosen

to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, and that the excess energy above load in that electrical area can be exported to the remainder of PJM. In short, the test attempts to ensure that bottled capacity conditions that limit the availability and usefulness of certified Capacity Resources to system operators will not exist. In actual operating conditions, energy-only resources may displace Capacity Resources in the economic dispatch that serves load."

Manual 14B, C.3, Deliverability of Generation, p. 86. Available at https://www.pjm.com/-/media/documents/manuals/m14b.ashx .

Capacity resources achieve this level of deliverability when, as part of their interconnection procedure, they participate in a comprehensive set of required load flow studies that analyze whether any transmission upgrades will be needed to support their operation at time of peak load. If any such upgrades are needed, the capacity generator must pay its allocated share of them, which can be considerable. Similarly, it must pay for the studies themselves, which also can be a substantial cost.

Generators that do not want to participate in the capacity market can avoid these costs by choosing to interconnect as energy resources rather than as capacity resources. In return for the lower interconnection costs, they forego capacity market revenues. However, as the section of Manual 14B included above notes, these resources can still displace energy-only resources in PJM's energy market.

In light of these specific deliverability options, we make the following observations:

1. The options for deliverability available under the PJM tariff and mode of energy market dispatch and operation do not allow for the specificity of deliverability the staff questions above appear to contemplate:

    a. The most expensive and comprehensive form of generator deliverability available in PJM does not allow a specific generator outside of New Jersey to physically deliver the energy it produces to a New Jersey EDC. Instead, generators in PJM enter into financial "delivery" transactions related to the price of energy at the point where they may be injecting power into the PJM grid, and the price of energy at the point where energy is withdrawn from that grid by a load-serving entity. The actual physical flows of the energy making up the withdrawn MHW are unknown and unpredictable, and will occur due to PJM's SCED process even when the selling generator is not operating at all.

    b. It does not ensure that the "deliverable" generator will displace some other, more polluting generator in the dispatch process, or that it will run at all, at any particular time when New Jersey load serving entities are selling electricity to their customers in New Jersey.

    c. Further, no generator -- whether a deliverable capacity resource or a not-always-deliverable energy resource -- can in any way avoid respecting the thermal and stability limits associated with the transmission interface between New Jersey and other parts of PJM. The SCED process simply will not allow those limits to be exceeded in any specific dispatch interval, no matter what sort of deliverability the resource has qualified for. Further, even when the interface is constrained, it is only the incremental level of energy production, above those constraints, that is shifted to a locational dispatch "downstream" from the constraint; the full amount of energy up to the constraint can continue to flow across the interface.

2. While requiring deliverability would not achieve what we take to be the objectives articulated in the questions above, it would have significant implications for New Jersey. Specifically, requiring all new large-scale solar projects (inside or outside of New Jersey to interconnect as capacity resources would:

    a. Help reduce the risk of the projects' curtailment. The transmission upgrades associated with their development could help protect against curtailment at times of high wind speeds and solar irradiance. Without the added transmission required for capacity resources, these new projects could face a higher risk of becoming "bottled", and curtailed, due to inadequate transmission to export their production from the electrical area in which they are located (which could include New Jersey) to electrical regions where there is sufficient demand to consume any excess power produced in their own electrical region(s).

    b. Increase large scale solar interconnection costs, relative to those they would incur if they choose to interconnect as energy-only projects.

    c. Allow them to participate in the PJM capacity market or to qualify as UCAP for the purpose of an FRR, should New Jersey elect to adopt an FRR for some or all of its LSE's UCAP obligation. The resulting UCAP revenues would offset some or all of the additional interconnection costs.

In light of all the above considerations, we would caution against any including any "deliverability" or "delivery" requirements per se in the Successor Program. Instead, we recommend the BPU consider, instead, between the alternatives of requiring large scale solar projects to interconnect as:

1. capacity resources,
2. energy-only resources,
3. or allowing them to choose as they see fit and selecting projects based on their bid levels alone.

One benefit of the third approach is it would rely on bidding projects to determine which way their net costs would be lower -- that is, whether their expected UCAP sales revenues (e.g. through a unit-specific exemption to the MOPR, or through sales to an FRR entity), would be higher or lower than the added interconnection costs, rather than trying to administratively determine the best result in advance.

Topic 2: Modeling

The modeling conducted by Cadmus and described in the draft Capstone Report was largely informed by the assumptions used in the Transition Incentive program modeling, updated cost data from projects in the SRP, and subsequent stakeholder engagement such as the March 2020 Successor Program cost survey. Staff is interested in stakeholder feedback on Cadmus' assumptions and modeling choices. Staff has identified a number of specific questions below, but encourages stakeholders to share their assessment of the model and modeling assumptions beyond the focus of these questions.

7) Is Cadmus' breakdown of SAM cases, as identified in Table 12 (p. 32), appropriate? Why or why not?

8) Please provide feedback on Cadmus' SAM model inputs, as identified in the draft Capstone Report and the supplemental modeling spreadsheet. In particular, please provide feedback on the following assumptions:

a. Modeled system size (Table 13, p. 34). For example, how could the adoption of the 2018 building codes and subsequent changes to residential systems setback requirements impact system size?

b. Installed costs (Table 17, p. 39). What are factors that could impact installed costs moving forward? Has Cadmus correctly identified installed cost assumptions for the out-of-state solar and community solar SAM cases?

c. Financial parameters, including interest rates and loan terms (Tables 19 and 20, p. 43).

d. Revenue assumptions. In particular, please comment on the ability to quantify projects' demand charge reduction (see Cadmus' modeling note on p. 45).

e. Specific energy production and energy degradation rate (see Cadmus' modeling note on p. 61).

f. Investment Tax Credit ("ITC"). Should NJBPU assume that non-residential projects are able to safe harbor under the 2020 ITC at 26% (similar to the approach adopted in 2019 for the Transition Incentive Program)?

9) Do you agree with Cadmus' derivation of wholesale and energy prices, as presented in Table 21 (p. 46)? If not, how would you recommend modifying Cadmus' approach?

10) Cadmus provided different approaches to modeling the MW targets (see section 4.3, p. 50 - 56). How should NJBPU set the MW targets, while maintaining compliance with the legislative cost caps?

Regarding how to set MW targets while maintaining compliance with the legislative cost caps, see the budget-based target allocation recommendation on page 11 of the February 22, 2019 comments of NJCF, NRDC, EDF, NJLCV, and rethinkenergy.nj on New Jersey's Solar Transition Straw Proposal, as included in our additional comments below.[2] Such budgeting may require interventions or modifications in the legacy SREC program to ensure adequate headroom is available under the cost caps to support higher cost in-state resources while also ensuring achievement of the state's RPS goals. See additional comments below for a summary of recommendations articulated by NJCF and NRDC in multiple prior solar transition comments.

11) Cadmus recommends that NJBPU consider whether to differentiate treatment between direct-owned ("DO") projects and third-party owned ("TPO") projects. Please comment.

12) Please comment on the transparency and replicability of Cadmus' incentive modeling: if NJBPU were to implement an administratively determined incentive, could this model serve as the basis for setting the incentive value going forward? If not, what changes would need to be made to make it suitable?

13) Please provide general feedback on Cadmus's modeling inputs, methodology,

[2] The relevant comments are included in the "additional comments" section below.

and assumptions not already addressed in a previous question.

Additional comments:

A. Land use

Land-use considerations and siting should be a bright-line set of evaluation criteria, rather than a weighted set of evaluation criteria. If BPU provides clarity about lands that are not eligible, then eligible bids can be evaluated solely on price. The Energy Master Plan included sound language regarding the importance of siting and how to approach it:

> For solar energy, investments should be steered toward rooftops, carports, and marginalized land and away from open space. Further, in concert with New Jersey's Climate Resilience initiatives, investments should be steered away from flood zones and other areas deemed especially vulnerable to climate change.
>
> 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. For example, there are areas of non-preserved farmland that may have poor soil conditions, or non-pristine open spaces that are underutilized, both of which could potentially serve as host sites for solar projects while not compromising the state's commitment to preserve open space. Dual-use opportunities may exist for siting solar on areas of open space or non-preserved farmland, but they must be examined carefully for environmental impacts. 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, p.112, emphasis added)

To operationalize this within the SREC successor program, lands should be identified that are eligible for incentives under the program, as well as lands that are ineligible. Ineligible lands should include the following:

(1) preserved farmland. For the purposes of this paragraph, "preserved farmland" means land on which a development easement was conveyed to, or retained by, the State Agriculture Development Committee, a county agriculture development board, or a qualifying tax exempt nonprofit organization pursuant to the provisions of section 24 of P.L.1983, c.32 (C.4:1C-31), section 5 of P.L.1988, c.4 (C.4:1C-31.1), section 1 of P.L.1989, c.28 (C.4:1C-38), section 1 of P.L.1999, c.180 (C.4:1C-43.1), sections 37 through 40 of P.L.1999, c.152 (C.13:8C-37 through C.13:8C-40), or any other State law enacted for farmland preservation purposes;

(2) land preserved under the Green Acres Program. For the purposes of this paragraph, "Green Acres program" means the program for the acquisition of lands for recreation and conservation purposes pursuant to P.L.1961, c.45 (C.13:8A-1 et seq.), P.L.1971, c.419 (C.13:8A-19 et seq.), P.L.1975, c.155 (C.13:8A-35 et seq.), any Green Acres bond act, P.L.1999, c.152 (C.13:8C-1 et seq.), and P.L.2016, c.12 (C.13:8C-43 et seq.);

(3) land located within the preservation area of the pinelands area, as designated in subsection b. of section 10 of P.L.1979, c. 111 (C.13:18A-11);

(4) land designated as forest area in the pinelands comprehensive management plan adopted pursuant to P.L.1979, c.111 (C.13:18A-1 et seq.);

(5) land designated as freshwater wetlands as defined pursuant to P.L.1987, c.156 (C.13:9B-1 et seq.), or coastal wetlands as defined pursuant to P.L.1970, c.272 (C.13:9A-1 et

seq.);

(6) lands located within the Highlands preservation area or Highlands Agricultural Resource Area as designated in subsection b. of section 7 of P.L.2004, c.120 (C.13:20-7);

(7) lands prioritized for farmland preservation by the NJ SADC, Municipalities or County Agricultural Development Boards as identified by Agricultural Development Areas and Farmland Preservation Project Areas;

(8) upland forests as identified by NJ DEP land-use, land-cover maps; and

(9) critical wildlife habitat ranked 3, 4 or 5 in the State of NJ Landscape Project.

Eligible lands should include the following:

(1) Brownfields

(2) Landfills

(3) Rooftops

(4) Parking lots and decks

(5) Areas of historic fill

(6) Areas designated as in need of redevelopment

(7) Canopies over impervious surfaces

(8) Marginal farm or other open lands that fall outside of the ineligible lands above

B. Budget-based MW targets for the Successor Program (from NJCF, NRDC and NJLCV comments on Solar Transition Straw Proposal of February 22, 2019):

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 state's Energy Master Planning process.

C. Headroom conservation to support RPS goals and diverse clean energy resources consistent with the legislative cost caps:

In NJCF and NRDC solar transition comments of January 31, 2020, we reviewed and summarized previous filed recommendations for

> "a 'price collar' approach, with the top end of the price range constrained by a mechanism that would function like the SACP, but would be established at a lower level by the BPU under its authority to do whatever is necessary to ensure compliance with the RPS cost caps. We have suggested evaluation and careful consideration of several alternatives for the mechanism that would create the price floor, including a buyer of last resort approach, and an opt-in to a new solar compensation program that would offer a fixed price for a fixed term. If the combination of this lower price and a longer term were more attractive than the [price] levels to which the legacy program could fall, enough legacy projects could be expected to voluntarily opt-out of the legacy market and into the new, fixed price program to cause SREC prices to fall to the level of the new program. Such a program could, for example, be set up as part of the successor program or potentially even as part of the modified SREC program."

Now that the SREC program is closed and better insights are available into its length and potential prices in the post-closure period, we recommend the BPU explore the potential need for such measures to ensure adequate headroom for the Successor Program.