Docket No. QO21101186, IN THE MATTER OF COMPETITIVE SOLAR INCENTIVE ("CSI") PROGRAM PURSUANT TO P.L. 2021, C. 169

Joint Comments of the Solar Energy Industries Association and the New Jersey Solar Energy Coalition

December 14th, 2021

I. Executive Summary

The Solar Energy Industries Association (SEIA), New Jersey Solar Energy Coalition (NJSEC), and Mid-Atlantic Renewable Energy Coalition Action (MAREC Action) appreciate the opportunity to offer input to the New Jersey Board of Public Utilities (BPU or Board) regarding the design of the Competitive Solar Incentive (CSI) program. We appreciate the BPU and Staff's continued engagement on these critical questions that will determine whether New Jersey meets the Murphy Administration's Energy Master Plan goal of 17 gigawatts of solar deployed by 2035.

In brief, we need to deploy a lot more solar, including grid-scale solar facilities in New Jersey. We share the Board's interest in developing a competitive solicitation process that incentivizes the construction of at least 1,500 megawatts of large-scale solar facilities by 2026, including 300 MW each year.

However, we believe that getting the needed quantity of resources deployed—and deployed at the best price to ratepayers—will require the BPU to adopt the best procurement tools available as quickly as possible. We fear that the uncertainty of revenue streams associated with a fixed-price REC-only competitive procurment, where grid-scale solar facilities remain merchant for energy and capacity, will create financing hurdles for developers that could plague the CSI program before it even takes off.

Getting the program design right from the start will require thoughtful cooperation with industry and other stakeholders, and an innovative approach on behalf of the board. We caution that poor program design choices will make New Jersey's clean energy objectives much harder and more expensive to achieve.

As a result, we present the following high-level summary of CSI Program Design Preferences that build upon lessons learned by our members experiences across the United States:

- The CSI should include an option for REC-pricing that is indexed against reference wholesale market prices for a guaranteed term of 20 years, where projects bid in a "strike price" representing the entire revenue stream they need to build the project and SREC-II payments rise and fall inversely to reference energy and capacity revenues but never exceed the "strike price."
- Grid-scale projects that are not supported by any underlying economics such as net metering or community solar require price certainty from the REC itself. Fixed-Price SREC-II Contracts for grid-supply projects with no additional certainty on revenue streams are likely to lead to more

expensive projects since the fixed-price REC will have to support the economics of the project. Conversely, an indexed REC approach offers a REC-only solution for the BPU that partners with developers to manage wholesale market fluctuations and the limitations of unbundled contracts and is expected to drive down the price of the implicit REC over the contract period.

- The CSI should consist of separate solicitations that allow like projects to compete against like projects, with at least 130 megawatts each year allocated for “basic" greenfield grid-supply projects.
- Each CSI solicitation tranche should allow solar and storage projects to participate, with the option to submit a bid proposal for a facility without energy storage and a bid proposal for the same facility with energy storage.
- The CSI Program should include maturity requirements that strike a balance between reducing speculative bids from developers and recognizing that competitive solicitations are inherently riskier to developers since not all projects will be awarded incentives.
- The CSI program should have a streamlined process to extend completion deadlines for projects that are mechanically and electrically complete, have paid all EDC interconnection fees, and are simply waiting for EDC permission to operate.

Our comments are organized with an opening narrative section explaining our positions followed by specific answers to the questions posed by the BPU. These answers are designated using blue text. Unless otherwise specified, failure to comment on any specific question should be interpreted to mean that our organizations do not take a position on the matter at this time.

We look forward to working with the BPU to establish the CSI program and would be pleased to meet with Staff to discuss any of the recommendations contained in these comments.

II. The Case for Indexed RECs

What does it take to launch a successful large scale solar program?

The two most important things for launching a successful large scale solar program are sustained demand and revenue certainty. Incentivizing the construction of at least 1,500 megawatts of large-scale solar facilities by 2026, including 300 MW each year, should sustain demand. However, as we indicated in our initial comments regarding the creation of the Solar Successor Program, long-term bundled contracts are the most successful way to spur large-scale project deployment. If the Board is unable to provide a bundled PPA for large scale projects, we believe the next most appropriate mechanism is the indexed REC approach.

<u>Key Differences in Procurement Mechanisms</u>

Procurement Mechanism	Hedging Benefit	Cost of Financing	Grid and Ratepayer Impacts
Bundled PPA (Energy, capacity, and RECs)	Strong	Low	Project is not incentivized to maximize locational value; ratepayer benefits if wholesale market prices rise

Fixed-Priced REC	Weak	High	Project is incentivized to maximize locational value; ratepayers would not benefit if wholesale market prices rise
Indexed REC	Strong, but not as strong as bundled PPA	Low, but not as low as a bundled PPA	Project is incentivized to maximize locational value; ratepayers benefit if wholesale market prices rise

Fixed-Price SREC-II only contracts for grid-supply projects are likely to lead to more expensive projects.

If the BPU's objective is to incentivize the lowest financial contribution from ratepayers for grid supply projects, it's important to seriously consider the benefits of an indexed REC structure over a traditional fixed-price REC.

A fixed-price REC contract does not offer any energy revenue certainty to project investors, which is the largest part of the market value and revenue expectations for these projects. While projects could take steps to hedge their energy or capacity revenue, the presence of this risk leads investors and financial institutions to insist upon greater returns to their debt and equity, driving up project revenue requirements, which in turn will be embedded in higher bids at the expense of ratepayers. Furthermore, whereas merchant wind has increased, there are differences in financing merchant wind versus merchant solar, and limited progress to date on installing solar under merchant arrangements. A Resources for the Future whitepaper on this topic notes that "the significant transaction costs of structuring and financing a bank hedge could make this design unpractical for all but very large projects," the type of 100MW+ projects that, due to geographic constraints and siting restrictions, New Jersey's CSI program is unlikely to incentivize.[1]

Neighboring New York serves as a good guide for New Jersey given that the electricity market is structured similarly. New York until recently relied on a fixed-price REC-only Large-Scale Renewables Solicitation, but has tested multiple approaches to cost-effectively achieve its newly established aggressive clean energy and environmental mandate of 70% renewable electricity by 2030 and 100% zero-emission electricity by 2040.

In 2015, the New York State Energy Research and Development Authority (NYSERDA) released an assessment of Large-Scale Renewable (LSR) Development in New York that stated that "continued use of the fixed price REC contract as the primary LSR procurement vehicle poses risks for New York's ability to meet its objectives."[2] NYSERDA's analysis stated that bundled contracts (RECs, energy, and capacity) drive down the cost of the project and generally improves the financing for solar projects, decreasing the impact

[1] Bartlett, Jay. 2019. "Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges." Working Paper 19-06. Resources for the Future. https://media.rff.org/documents/WP_19-06_Bartlett.pdf

[2] See "Large-Scale Renewable Energy Development in New York: Options and Assessment" New York State Energy Research and Development Authority, June 2015. Available at: https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/Large-Scale-Renewable-Energy-Development.pdf

on ratepayers when compared to other procurement options. NYSERDA also stated that fixed-price REC contracts “may not be the most cost-effective or efficient structure” for facilitating financing and construction of new large-scale renewables energy development and acknowledged that “this type of contract may not be sufficiently attractive to incent developers to develop and build LSRs in New York, especially given more attractive alternatives available in New England and other regions, such as longer term utility contracts for bundled energy and RECs.”[3]

After NYSERDA analysis and stakeholder feedback demonstrated that changes to the current approach were warranted, in 2018, the NY Public Service Commission (PSC) adopted a variant of the Fixed-Price REC approach for offshore wind REC solicitations (ORECs).[4] This Order directed NYSERDA to require bidders to offer both a Fixed-Price OREC and an Indexed OREC Bid. Unlike a Fixed-Price OREC, the Indexed OREC was based on the developer’s estimated revenue requirement for the project (i.e. a strike price) and varied over the life of the contract based on the net difference between the strike price and a reference price expressed in a market index.

In 2020, the NY PSC ordered NYSERDA to implement an Indexed REC procurement mechanism similar to the OREC model for future large-scale solar and wind solicitations. This order noted that providing this option would “give developers more flexibility to adapt their bidding behavior to their financing and operational needs” and that “the use of an Index REC should also reduce the risk premiums that developers account for in their bids to accommodate for uncertainty in power market revenues, thereby lowering ratepayer costs on a per-REC basis.”[5]

Indeed, NYSERDA demonstrated that the indexed REC structure offered REC pricing benefits of at least $8 per MWh, in comparison to a Fixed-Price REC contract.[6] According to NYSERDA, these savings primarily result from the ability to hedge wholesale market revenues, as well as the resulting reduction in risk premiums that are normally embedded in Fixed-Price REC bids to compensate for the lack of hedging in those contracts. This report also noted that the introduction of an Indexed REC structure could potentially widen the pool of projects participating in Tier 1 REC procurements, thus increasing the overall competitiveness of the bidder pool.

An Indexed REC approach offers a way to avoid bundled contracts but still account for wholesale market risks.

In the BPU’s Solar Successor Straw Proposal, the BPU proposed that projects participating in the program also participate in the wholesale market to provide benefits to ratepayers. Indeed, participation in the wholesale market can result in additional revenues to the project that in theory could reduce the cost of the environmental attributes (or REC). However, given the risk of fluctuations in wholesale market prices,

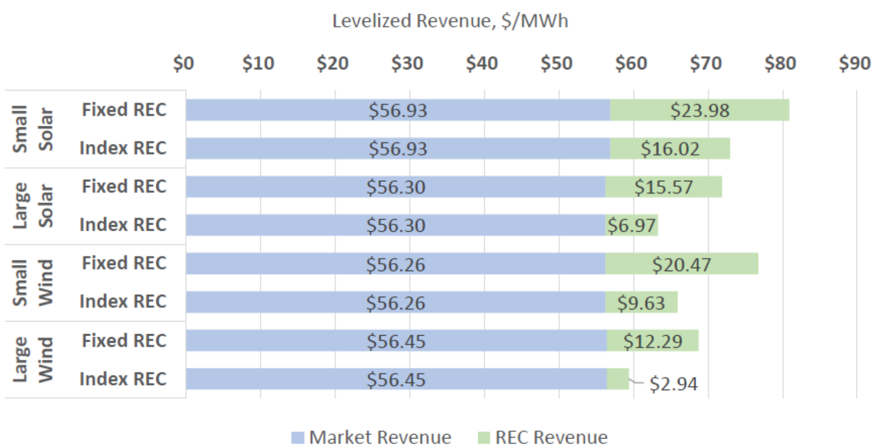
[3] See Page 66
[4] Case 18-E-0071, Offshore Wind Energy, Order Establishing Offshore Wind Standard and Framework for Phase 1 Procurement (issued July 12, 2018)(Offshore Wind Order).
[5] Case 15-E-0302 Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard. ORDER MODIFYING TIER 1 RENEWABLE PROCUREMENTS, January 16, 2020
[6] Case 15-E-0302 NYSERDA Comments on the AWEA/ACE-NY Petition Regarding Integration of an Index REC Procurement Structure into Tier 1 REC Procurements Under the Clean Energy Standard, Submitted by the New York State Energy Research and Development Authority October 2, 2019

and the fact that a project cannot be certain if its price will clear in the capacity auction, developers are unable to provide competitive prices when there is no price certainty or hedge.

The downside of a fixed-REC price or bundled PPA price from a ratepayer perspective is the "fixed" nature of the price. Given the absence of any certainty or hedge over the alternative revenue pathways, the fixed-price covers most of the costs of the project. For a fixed-price REC, that means that if higher wholesale market revenues flow to the developer, that revenue does not flow directly to ratepayers in the form of a reduced REC price.

The biggest benefit of indexed RECs is that the state basically de-risks the revenue for the developer/independent power producer. It acts as insurance, which allows the REC bids to be much more competitive. By shoring up the revenue, they can bring more debt to the project, which is far cheaper and means the project will require less total support from the REC. Based on any normal range of energy and capacity forecasts, the "implied" REC values should be much lower than fixed-price REC only bids. The projections described below from NYSERDA's analysis before the NY PSC support the expectation that an indexed REC structure provides significant cost-effectiveness benefits compared to a fixed-REC structure.[7]

Figure 4 from NYSERDA's Comments Regarding Integration of an Index REC Procurement Structure



A. How it works

Generators bid in an all-in "strike price" representing the entire revenue stream they need to build the project (for example: REC + energy + capacity). The REC payments therefore rise and fall inversely to total reference energy and capacity revenues. The Strike Price will be uniform for the full contract tenor. Calculation of Monthly Reference Prices (Energy Capacity) will reflect the facility's point of interconnection/delivery (zonal) and technology. Energy reference prices are set on a monthly average zonal day-ahead price. In New York's current program, the capacity prices are based on monthly zonal capacity price multiplied by the project's capacity factor as proposed by the developer. NYSERDA then converts the $/kW-month capacity price to kWh to align with a REC construct. Put differently, the REC cost will equal the strike price minus the energy reference price and capacity reference price.

[7] Case 15-E-0302 NYSERDA Comments on the AWEA/ACE-NY Petition Regarding Integration of an Index REC Procurement Structure into Tier 1 REC Procurements Under the Clean Energy Standard, Submitted by the New York State Energy Research and Development Authority October 2, 2019

Sample Calculation:

Implicit REC Price= Strike Price – Reference Capacity Price – Reference Energy Price

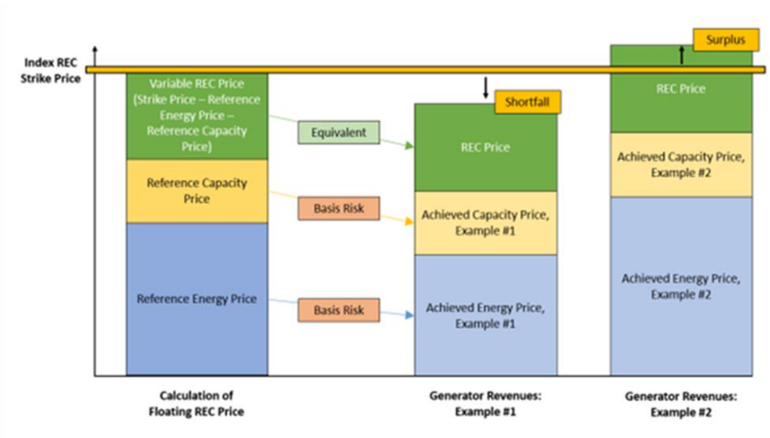
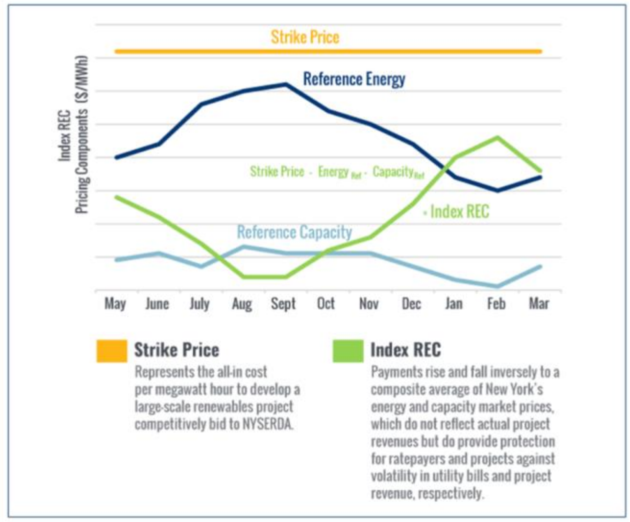


Figure 3: Example of commodity basis risk in the Index REC procurement structure.



B. Guidance to BPU

Should the BPU offer the option of an indexed REC, the BPU would need to contract with consultants to create a forward price curve for PJM energy and capacity prices. Each zonal point would have its own reference capacity and reference energy price. Each technology configuration would have a different assumption on capacity value based on its presumed PJM capacity prices/ELCC values (for more on this, read the section below). Bids would be selected from the lowest bid up to the bid that triggers the revenue cap for that solicitation based on the estimated implicit REC price for the BPU, not the strike price. The duration of the contract with the BPU should be 20 years rather than 15 years in order to make the prices more competitive. The shorter the tenure of the financial hedge, the more risk is involved, and therefore the higher the price. Most contracts we are seeing across the country are greater than 15 years. Reference prices would be calculated on a monthly average to simplify process and REC payments to developers would be settled once every month (monthly settlement period). In the event of a negative REC balance, a project can roll over that debit for a period of months rather than the developer transferring money back to the BPU.

C. ELCC Considerations

In the case of the current Large-Scale Renewables Solicitation program in New York, developers and NYSERDA calculate the capacity reference price for each project by multiplying the monthly zonal capacity prices by the capacity factor of the project. Given that the PJM market is transitioning towards an Effective Load Carrying Capability (ELCC) approach to quantify a project's capacity contribution and payment, the Board may want to incorporate the ELCC approach into its calculation of the capacity reference price. By incorporating the ELCC into the reference price, solar co-located with energy storage will be able to provide a competitive implicit REC price given the higher capacity price the systems will yield, resulting in ratepayer savings. At the same time, the potential for changes in the ELCC values as renewable energy and energy storage penetration increases in the PJM footprint must be balanced with the need for ratepayer security. We look forward to working with the BPU to find the right balance in the capacity reference price calculation that provides the greatest benefit to ratepayers and incentivizes the most cost-effective projects.

III. Overall CSI Program Design Recommendations

The CSI should consist of separate solicitations that allow like projects to compete against like projects, with at least 130 megawatts each year allocated for "basic" greenfield grid-supply projects.

We support the BPU's initial recommendation that each solicitation allocates at least 130 MW each year towards "basic grid supply projects." Ample stakeholder feedback has conveyed that it is inappropriate to combine the built environment, landfills, and contaminated sites into a single "desirable land uses" tranche given the vast differences in project costs for these very different project types. This is of particular importance given the legislative direction to select projects based on price. As a result, we support the BPU's recommendation that there be separate solicitation tranches to allow like projects to compete against like projects.

Specifically, we recommend the following division of at least 300 MW per year so that like projects can compete fairly against projects with similar costs and development challenges:

- Basic greenfield grid supply projects: 130 MW
- Grid supply projects in the built environment: 65 MW
- Grid supply projects on contaminated lands/landfills: 65 MW
- Net metered non-residential projects above 5 MW: 40 MW

Should the BPU elect to establish a confidential high and low bid threshold as authorized under statute, we recommend that each tranche have its own confidential "not to exceed" value for offers (maximum bid price in $/MWh), recognizing that projects on contaminated lands and landfills are likely to be higher cost than greenfield projects.

We have been consistent that a competitive solicitation for net-metered projects is not likely to be successful. However, we should not foreclose the opportunity to participate in a competitive solicitation for large net metered non-residential projects. As a result, we recommend that the BPU select projects up to the budget cap for each category from lowest to highest price bid. However, if there are insufficient bids in any solicitation category and that tranche's budget is not fully exhausted, we recommend that the BPU transfer and re-allocate that budget to select additional projects from another tranche, including towards additional awards for "basic" greenfield grid supply projects.

The CSI Program should include high maturity requirements that strike a balance between reducing speculative bids from developers and recognizing that competitive solicitations are inherently riskier to developers since not all projects will be awarded incentives.

While we agree with the recommendation to include high project maturity requirements to reduce speculative bids, we note that maturity requirements should match the program design. Given our recommendation for separate solicitations based on project type, it is appropriate to set different maturity requirements for different types of projects.

We agree with the need for demonstrating site control and some investment in interconnection but believe the BPU must also be mindful of developments related to PJM's Interconnection Process Reform Task Force, which may impact the ability for serious projects to enter the PJM Interconnection queue. We also believe that any deposit consideration should balance how much other investment has been spent on the project. Additionally, it is critical that developers have reasonable project commercial operations date (COD) targets but are able to extend their COD target if something out of their control is driving the delay, such as PJM interconnection delays.

Furthermore, projects on contaminated land and/or landfills require more flexibility. These projects typically require additional agency approvals and are often done under public bid processes that can take an additional six to nine months to complete. As a recent RMI study, *The Future of Landfills is Bright: How State and Local Governments Can Leverage Landfill Solar to Bring Clean Energy and Jobs to Communities Across America* notes, project designs must account for landfill cap characteristics, site grading, land settlement as waste decays over time, existing on-site infrastructure, community concerns, and interdepartmental coordination.[8] As a result of these considerations, the RMI report notes that permitting and project approval are subjected to a more complex review than for greenfield sites. Many of these requirements may have a significant impact on time to complete site preparation work as well as the additional time associated with construction activities. Furthermore, it is also important to note that while technical diligence may take less time for the developer to reach critical conclusions and findings about site conditions, rarely is the developer making a unilateral decision. Instead, the developer must work with parent companies, financing parties, joint venture partners, and the like as applicable—each of whom has a separate standard and process for environmental diligence.

Given the desire to ensure more projects are able to reach commercial operation if they are offered a REC contract, and to avoid speculative bids for projects that will send inaccurate price signals, we recommend the following maturity requirements by project type/solicitation tranche:

- **Recommended maturity requirements for "basic" greenfield grid supply projects:**
    - All projects should be assigned a completion deadline of 36 months from the date they are awarded a contract, with the possibility of two six-month extensions
    - Posting a reward deposit of $40/kW of DC nameplate capacity of the solar facility in an escrow account to hold allocated CSI capacity to be reimbursed to the applicant in full upon either (i) the project not being awarded a contract through the competitive solicitation, or (ii) upon attainment of permission to operate
    - The project has commenced a System Impact Study from PJM or has a completed interconnection study from an EDC for distribution-level interconnections;
    - The BPU may need to reconsider maturity requirements, pending ongoing developments related to PJM's Interconnection Process Reform Task Force
    - Demonstrated site control via an executed lease for the duration of the proposed REC contract or purchase agreement, or a contractual arrangement that is long enough to align with the interconnection process
    - Quarterly description of milestones that have been reached in Project development (e.g. status of interconnection, required federal, state, and local permits, etc.)

[8] Matthew Popkin and Akshay Krishnan, The Future of Landfills Is Bright: How State and Local Governments Can Leverage Landfill Solar to Bring Clean Energy and Jobs to Communities across America, RMI, 2021, https://rmi.org/insight/the-future-of-landfills-is-bright.

- **<u>Recommended maturity requirements for grid supply projects in the built environment:</u>**
  - All projects should be assigned a completion deadline of 36 months from the date they are awarded a contract, with the possibility of two six-month extensions
  - No deposit required
  - The project has commenced a System Impact Study from PJM or has a completed interconnection study from an EDC for distribution-level interconnections;
  - The BPU may need to reconsider maturity requirements, pending ongoing developments related to PJM's Interconnection Process Reform Task Force
  - Demonstrated site control via an executed lease for the duration of the REC contract or purchase agreement, or a contractual arrangement that is long enough to align with the interconnection process
  - Quarterly description of milestones that have been reached in Project development (e.g. status of interconnection, required federal, state, and local permits, etc.)

- **<u>Recommended maturity requirements for grid supply projects on contaminated lands/landfills</u>**
  - All projects should be assigned a completion deadline of 36 months from the date they are awarded a contract, with the possibility of two six-month extensions
  - No deposit required
  - Provide documentation that describes milestones in the development of the project that have been reached to date including the status of remediation of the project site and obtaining approval to install solar energy projects on closed sanitary landfills under New Jersey's Solid Waste Regulations, N.J.A.C. 7:26 et seq., and other Department programs
  - Provide documentation that demonstrates compliance with applicable environmental rules and regulations
  - The project has commenced a System Impact Study from PJM or has a completed interconnection study from an EDC for distribution-level interconnections;
  - The BPU may need to reconsider maturity requirements, pending ongoing developments related to PJM's Interconnection Process Reform Task Force
  - Demonstrated site control via an executed lease for the duration of the REC contract or purchase agreement, or a contractual arrangement that is long enough to align with the interconnection process
  - Quarterly description of milestones that have been reached in Project development (e.g. status of interconnection, required federal, state, and local permits, etc.)

- **<u>Recommended maturity requirements for net metered non-residential projects above 5 MW:</u>**
  - All projects should be assigned a completion deadline of 24 months from the date they are awarded a contract, with the possibility of two 6-month extensions
  - No deposit required
  - A signed customer letter of intent, or a notice of conditional award for a public entity

IV. Response to BPU Staff Questions

1. The Solar Act of 2021 stipulates that "[t]he development of grid supply solar should be directed toward marginal land and the built environment and away from open space, flood zones, and other areas especially vulnerable to climate change." Staff proposes to implement this requirement mainly through some form of incentive or segmented procurement targeting development on the built environment as well as on contaminated land or landfills. Staff is looking for input on the following questions:

a. Do projects on contaminated land and/or landfills need special consideration when it comes to project maturity and Commercial Operation Date ("COD")? If so, why?

Yes. These projects require multiple agency approvals and are often done under public bid processes that can take an additional six to nine months to complete. Projects on contaminated land and/or landfills should be granted special considerations particularly as it relates to requirements imposed by the Department of Environmental Protection for all site preparation, and construction work on and around these environmentally sensitive areas. A recent RMI study, *The Future of Landfills is Bright: How State and Local Governments Can Leverage Landfill Solar to Bring Clean Energy and Jobs to Communities Across America* notes that project designs must account for landfill cap characteristics, site grading, land settlement as waste decays over time, existing on-site infrastructure, community concerns, and interdepartmental coordination.[9] As a result of these considerations, the RMI report notes that permitting and project approval are usually subjected to a more rigorous review than for greenfield sites. Many of these requirements may have a significant impact on time to complete site preparation work as well as the additional time associated with construction activities. Furthermore, it is also important to note that while technical diligence may take less time for the developer to reach critical conclusions and findings about site conditions, rarely is the developer making a unilateral decision. Instead, the developer must work with parent companies, financing parties, joint venture partners, and the like as applicable—each of whom has a separate standard and process for environmental diligence.

b. What additional costs, if any, are associated with development on contaminated land and/or landfills?

The beneficial but simple-sounding transaction of building solar on contaminated lands is actually highly complex and risky at any one site. It is reasonable to anticipate higher permitting, engineering, legal, environmental and structural reviews as additional costs for development on contaminated land and/or landfills, as well as greater risks of cost increases. Additionally, many of these sites require additional insurance coverage/costs, PRP (potentially responsible parties) plan budgeting and cost allocation and annual site O&M costs to manage non-solar site costs such as landfill cap management. Finally, whereas ground-mounted solar panels on a greenfield are typically anchored below the surface, ground-mounted solar on contaminated land and/or landfills are typically not anchored to avoid disturbing the soil. Instead, they are often secured by a system akin to pontoons to keep them stable on the land but not anchored below the surface. This is more expensive construction.

c. To the extent that the purpose is to avoid, as much as possible, the development of open space that might otherwise be available for other purposes, are there other siting options, besides the built environment, contaminated land and landfills, that should be given preference?

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[9] Matthew Popkin and Akshay Krishnan, The Future of Landfills Is Bright: How State and Local Governments Can Leverage Landfill Solar to Bring Clean Energy and Jobs to Communities across America, RMI, 2021, https://rmi.org/insight/the-future-of-landfills-is-bright.

Yes. We believe that “agrivoltaics” or dual use projects should be given preference. While we plan to engage in the forthcoming stakeholder process regarding the design of a dual use pilot program and eventual permanent program, we recommend that to the extent the BPU decides that dual-use projects receive competitive incentives instead of administratively determined incentives, they should participate in a separate tranche of solicitations where dual-use projects bid against other dual-use projects. While the BPU has thus far indicated no interest in including adders within the SuSi program, we note that as the densest state in the country, New Jersey has an acute need to maximize solar development on the existing built environment, especially surface and garage parking canopies/carports. Canopies and carports will be essential infrastructure when building out a resilient electric vehicle charging network. And, canopies change the character of parking lots by managing stormwater run-off and reducing heat island effects. Incorporating adders for surface garage parking canopies/carports within the built environment competitive solicitation (and ADI Program) will further embed NJ’s preferred siting and state policy objectives within the SuSi’s program design and better incorporate the market realities of developing different types of solar projects, including those that have broader environmental benefits but come at a cost premium in design and construction.

2. The Solar Act of 2021 stipulates that larger net metered non-residential projects (over 5 MW) be eligible to participate in the CSI Program:
    a. Does net metered status provide a benefit that is likely to be reflected in lower-cost bids in response to a competitive SREC solicitation?

       Net metered nonresidential projects over 5 MW will rely substantially upon the underlying economics associated with the project's negotiations with the roof owner in negotiating a long-term lease, and power off taker in a similar negotiation resulting in a long-term power purchase agreement. As has been observed previously, these negotiations are both extensive, and expensive since they result in unique legal documents. Due to economies of scale, it is possible that a competitive process may result in bids lower than the administratively determined incentives for smaller rooftop projects. However, developers may not find it attractive to incur significant expenses in advance of entering the competitive solicitation process, nor would many customers be interested in entering into prolonged and expensive PPA negotiations for a project that is subject to a competitively bid and low probability award.

    b. What kind of project maturity requirements would be appropriate for net metered projects?

       Given that developers may not find it attractive to incur significant expenses in advance of entering the competitive solicitation process, nor would many customers be interested in entering into prolonged and expensive PPA negotiations for a project that is subject to a competitively bid and low probability award, we recommend a signed customer letter of intent, or a notice of conditional award for a public entity. Additionally, due to the scale and scope of these projects, they should be provided with at least 24 months for commercial operation after winning the competitive solicitation. In all cases an extension process should be clearly outlined in the event the project encounters utility delays or force majeure events outside of the customer or developer's control. Indeed, we recommend that the CSI program have a streamlined process to extend completion deadlines for projects that are mechanically and electrically complete, have paid all EDC interconnection fees, and are simply waiting for EDC permission to operate.

3. To maximize the competitiveness of the solicitation process, and also to capture additional potential benefits to the public, it is Staff's intention to propose a CSI Program design that facilitates public entities' participation:
    a. Are there special barriers public entities might face in participating in competitive SREC solicitations? If so, what are they? Are there ways NJBPU could help eliminate barriers?

       It will be extremely difficult for any public entities with opportunities >5MW to participate in the SuSi program/any competitive process aspect as previously noted by SEIA and NJSEC. Municipal procurement requirements are extensive and complicated. A complete review of this body of law is required to understand the circumstances that will flow from these laws complicating the public entity's participation in the competitive solicitation program. In order to remove multiple barriers and to maximize public entity participation, they should not be subject to a competitive bid process. Please note, they are also largely unable to participate in community solar offerings statewide due to how credit values are calculated.

4. Staff aims to propose a solicitation design that results not only in awards, but in successful project development. To facilitate this, some combination of project pre-qualification requirements, COD requirements, participations fees, and/or escrow requirements are being considered:
    a. Should Staff consider recommending a requirement that projects have completed a Facilities Study?

       No. The time and cost of obtaining these studies could create periods of up to 36 to 40 months. Our preference is that interconnection application has been submitted and all associated fees paid, and then that all projects have *commenced* their Feasibility Study (FES) or System Impact Study (SEIS). However, we do not believe this should apply to net metered non-residential projects above 5 MW, who should only require a customer letter of intent, or a notice of conditional award for a public entity. Additionally, we believe the BPU must also be mindful of developments related to PJM's Interconnection Process Reform Task Force, which may impact the ability for projects to enter the PJM Interconnection queue.

    b. What about having a requirement for a completed or draft System Impact Study?

       These studies reflect an early stage of the interconnection process, but mean projects are starting to get real cost and feasibility information, which will result in more accurate bids and a higher project success rate. For all grid supply projects, it is reasonable that an interconnection application has been submitted and all associated fees paid, and then that all projects have *commenced* their Feasibility Study (FES) or System Impact Study (SEIS). However, the BPU must also be mindful of developments related to PJM's Interconnection Process Reform Task Force, which may impact the ability for projects to enter the PJM Interconnection queue.

c. Are there other PJM queue position requirements that should be considered?

   For all grid supply projects, it is reasonable that an interconnection application has been submitted and all associated fees paid, and then that all projects have *commenced* their Feasibility Study (FES) or System Impact Study (SEIS). We agree with the need for some investment in interconnection but believe the BPU must also be mindful of developments related to PJM's Interconnection Process Reform Task Force, which may affect the ability for projects to enter the PJM Interconnection queue.

d. At what point in the process would an SREC-II award provide the most value in terms of preventing projects dropping out of the queue?

   The BPU should balance offering certainty to developers earlier in the development process in order to make good investment decisions with the need for developers to have some investment in interconnection to avoid speculative projects.

e. What would the impact of other project maturity evidence requirements be (e.g. site control, evidence of ROW control, evidence of community engagement)?

   Demonstrated site control via an executed lease for the duration of the REC contract or purchase agreement or a contractual arrangement that is long enough to align with the interconnection process will ensure more projects are able to reach commercial operation if they are offered a REC contract and will avoid speculative bids for projects that will send inaccurate price signals and ultimately not come to fruition.

f. NYSERDA requires bid participation fees ranging from $5,000 to $100,000 depending on the size of the project. What is the right level for a 5 MW project versus a 20 MW project?

   The CSI Program should include high maturity requirements that strike a balance between reducing speculative bids from developers and recognizing that competitive solicitations are inherently riskier to developers since not all projects will be awarded incentives. Deposit considerations should balance how much other investment has been spent on the project. For basic greenfield grid supply projects, we recommend posting of a deposit of $40/kW of DC nameplate capacity of the solar facility in an escrow account to hold allocated CSI program capacity, to be reimbursed to the applicant in full upon either (i) the project not being awarded a contract through the competitive solicitation, or (ii) upon attainment of permission to operate. However, we do not recommend a deposit for grid supply projects in the built environment or Contaminated Lands/Landfills, or Net-Metered non-residential projects above 5 MW.

5. New Jersey's current practice is to provide subsidies such as SREC-IIs through administrative rules developed pursuant to statute, not through contracts. Staff requests input from developers about whether there are any implications on project cost, risk premium or other aspects of project financing purposes to providing incentives through administrative rules versus developing a standard contract.

Not having an actual contract that specifies that project's incentive value, terms, and conditions does create additional financing hurdles, increases underwriting time and does limit the pool of investors/banks willing to underwrite such deals. The TREC program had a similar construct, so the SuSi program will benefit from some of the ground already paved with lenders under the TREC, particularly for net-metered projects and projects on contaminated lands and landfills. However, moving to an actual incentive contract would make developer and customer lives easier, and slightly streamline underwriting, though it is difficult to say with certainty how much additional benefit projects and customers would recognize.

That being said, our chief financing concern is that a fixed-price REC-only competitive procurment, where grid-scale solar facilities remain merchant for energy and capacity, will create financing hurdles for developers. We believe than an Indexed REC approach offers a way to avoid bundled contracts but still provide a hedge against wholesale market risks. While this model comes with greater administrative complexity, we agree with the NY PSC's assessment that the use of an Indexed REC reduces the risk premiums that developers account for in their bids to accommodate for uncertainty in power market revenues, thereby lowering ratepayer costs on a per-REC basis.[10]

6. Staff invites stakeholder comments on how the qualifying life for receiving SREC-IIs impacts project financeability, total cost, and ratepayer risk.

Most PV projects today assume a 35-year equipment/asset life. Increasing SREC life to 20-25years will likely provide additional benefit to overall project economics and reduce the annual cost to ratepayers. We highly recommend at least a 20-year tenor for basic grid supply projects but note that many NJ public agencies cannot contract for more than 15yrs, and rooftop projects generally only can operate <20 years prior to roof replacement. For this reason, solicitations for the built environment, net metered non-residential projects above 5 MW, and projects on contaminated lands/landfills should have the option for a 15-year qualifying life, whereas other projects should have a 20-year qualifying life.

Sincerely,

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[10] Case 15-E-0302 Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard. ORDER MODIFYING TIER 1 RENEWABLE PROCUREMENTS, January 16, 2020

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