



1133 15th Street, NW | 12th Floor
Washington, DC 20005
202-540-9162 | info@communitysolaraccess.org
communitysolaraccess.org

March 1, 2019

Ms. Aida Camacho-Welch
Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
CN 350
Trenton, New Jersey 08625

Via Electronic Submittal: solar.transitions@bpu.nj.gov

Re: New Jersey Solar Transition Staff Straw Proposal (“Straw Proposal”)

Dear Ms. Camacho-Welch:

The Coalition for Community Solar Access (“CCSA”) respectfully submits these comments on the questions posed by the New Jersey Board of Public Utilities (“BPU” or the “Board”) regarding the SREC transition straw proposal and questions raised in BPU’s December 26, 2018 notice. Given the complexity involved in designing a successful transition of the SREC market we look forward to continued engagement on these topics on an expedited basis.

I. Introduction

New Jersey’s SREC program has been a success, helping build one of the largest solar markets in the country, including over 100,000 solar systems installed in the state. Going forward, by providing differentiated compensation to different types of projects through SREC “factors”, the state can deploy more capacity at lower cost while meeting goals the state has such as encouraging solar projects to be built on more expensive locations such as roofs and parking lots and supporting access to solar for low and moderate income customers. Indeed, as community solar is the option for a majority of residents, the SREC successor program should be designed with an eye toward enabling nearly 300 MW per year of community solar to meet the 219,000 to

400,000 customers (including 119,000 to 225,000 low and moderate income customers) that community solar could serve by 2030¹.

As the state develops an SREC successor program, an interim program is needed to support the development of projects in Energy Year 2020, which commences this June. While some projects have been expected to be able to move forward in the absence of such a program, ambiguity on the bill credit provided to Community Solar Pilot Program customers in the final rules published February 19, 2019 raises doubts about this remaining the case. In Section III below we detail needed clarifications to the community solar bill credit rate with respect to its viability for commercial, institutional, and LMI anchor tenants; as well as clarification of the inclusion of nonbypassable charges. If BPU does not clarify the rules accordingly, there will be an increased need for an interim SREC program in order to enable robust and diverse community solar deployment of the sort BPU has indicated it is hoping to see under the pilot program.

In CCSA's comments, which follow, we outline the need for an interim program, the viability of the pilot program in the absence of such an interim program, the market potential for community solar by 2030 and how an SREC program can support the expansion of the pilot program in years 2 and 3 and the establishment of the permanent program in 2021. CCSA then explains this SREC successor factoring proposal which is supported by analysis done by Gabel Associates enclosed as Appendix A. Finally, CCSA answers each of the questions raised by the Board in its December 28, 2018 notice.

II. An interim program for Energy Year 2020 is needed for a robust community solar pilot program

Community solar creates an opportunity to achieve the state's clean energy and climate goals cost-effectively while empowering customers who heretofore have been unable to participate in the transition to a clean energy economy because they are renters, have a home or business that cannot host a solar system, or are otherwise unable to be a rooftop solar customer.

In its July 31, 2018 comments provided to the Commission pursuant to the development of the Community Solar Pilot Program, CCSA demonstrated that the current 5.1% solar carve out in the Renewable Portfolio Standard will be unable to accommodate community solar projects given the large number of other projects already in the queue for registration in the SREC program. As a number of parties highlighted at the January 18th workshop, the current pipeline of projects will exceed the 5.1% target once all those projects are operational. This provides for a very uncertain investment environment for larger projects with longer development timelines, such as community solar projects.

As noted by a number of parties at the SREC stakeholder meetings held on October 17th, 2018 and January 18th, 2019, an interim SREC program is needed. Given the current timing of the BPU Staff Straw proposal, we and other stakeholders anticipate that any interim program, should it be created, will be in place for one energy year (EY 2020: June 2019-June 2020). For such a program to support projects being financed in EY 2020, the Board must pass an order

¹ GTM Research for Vote Solar, "The Vision for U.S. Community Solar: A Roadmap for 2030", July 2018, <https://votesolar.org/policy/policy-guides/shared-renewables-policy/csvisionstudy/>

establishing an interim program by June; without such an order project development is likely to be stalled for those projects requiring SRECs to be financed. Projects will not be financed based on expectations of an interim program being established retrospectively when the Board establishes final rules in March 2020 as anticipated by the Staff Straw Proposal.

III. Ambiguity on Bill Credit Definition in Final Community Solar Pilot Program Rules Provides Additional Uncertainty on Program Launch and is in Addition to Disadvantageous Provisions in the Final Community Solar Program Credit Rate.

Absent an interim SREC program, CCSA has expected some projects to apply to the community solar program and be successfully built. However, the ability of the pilot program to launch without an SREC program in place is now in question due to ambiguity in the final pilot program rules.

The draft rules set forth a retail rate bill credit to be provided to community solar projects for the life of the system, which provides optimal value for community solar customers. Unfortunately, the final rules set forth a tariff term of only 20 years. Given that the useful life of a typical community solar project is 35+ years, this 15+ year reduction in tariff term significantly changes the economic viability of community solar projects, and means that a pilot program with diverse projects is more dependent on SRECs.

CCSA also emphasizes that crediting customers at their own service class's retail rate, rather than using the residential retail rate, means that projects will be subscribed fully by non-demand rate customers, meaning that project financing will be more expensive, customer acquisition and management will be more expensive, and LMI projects will be more challenging and likely impossible absent other policy interventions.

a. Clarifying bill credit is necessary

There is ambiguity in how the bill credit is going to be calculated based on the final rules published in the state register on February 19th.

The final rule, at 14:8-9.7 states that:

(a) The value of the bill credit shall be set at retail rate net metering, inclusive of supply and delivery charges. (emphasis added)

(b) The calculation of the value of the bill credit shall remain in conformance with retail rate, as determined in (a) above and shall remain in effect for the life of the project, defined as no more than 20 years from the date of commercial operation of the project or the period until the project is decommissioned, whichever comes first.

(c) The credit may not be applied to fixed, non-by-passable charges. (emphasis added)

The definition in the final rule suggests that the retail rate credit is inclusive of all delivery charges, including the nonbypassable charges. However, in the Hearing Officers Report responding to comment 257, it is stated that:

...The Pilot Program bill credit is set at retail rate, minus non-bypassable charges (N.J.A.C. 14:8-9.7(a)), a cost structure that will have a lower cost impact to ratepayers.

CCSA believes that the response in the Hearing Officer's Report enclosed with the final rules is a misstatement of the rules as they are published, which ensures customers pay nonbypassable charges by making them non-offsetable with bill credits from community solar projects (i.e., "may not be applied to..."). For example, if a customer had a \$100 electricity bill and \$100 of bill credits, but \$10 of their bill was nonbypassable charges, they could only offset \$90 of their bill. This is different from reducing the bill credit amount by the \$/kWh value of the of the nonbypassable charges, which would not prevent customers from offsetting the NBCs in the bill but rather would just reduce the bill credit amount. If nonbypassable charges are removed from the credit that would constitute a 5.5 to 12.3% reduction in bill credit value and could make projects unviable even in the limited situations where they may be viable currently despite the uncertain SREC market.

Should the bill credit amount be clarified to be *inclusive* of all delivery charges (i.e., including nonbypassable charges) some projects may be viable despite the uncertainty in the SREC market. Even in this case, community solar projects will not be built to the volumes desired in all utility territories, in the diversity of siting and customer forms sought, or to the overall volume needed without those future SREC programs. Specifically, the first community solar projects will generally only be ground mounted projects with reasonable interconnection costs in the service territories with higher bill credits and lower land costs. However, should the state want to see projects being built in service territories with lower bill credits, built in more expensive locations (e.g., those on rooftops, parking lots, and additional brownfields and landfills), and serving Low and Moderate Income customers, SREC programs are essential.

In the short term, an interim SREC program could ensure that the community solar pilot has a robust launch and can help achieve some of the Board's associated policy goals, such as enabling the LMI projects which are targeted to constitute 40% of the community solar program and will be challenging to develop in the absence of clarifications to the program regulations and additional mechanisms such as consolidated billing with purchase of receivables.

IV. A successor SREC program can support 3 gigawatts of community solar by 2030 while achieving siting objectives and serving low-and-moderate income customers

Beginning in June 2020 a successor SREC program should be in place and take advantage of the cost effectiveness of community solar to support an expansion of the community solar pilot program in 2020 and 2021.

It is critically important that any SREC program not limit the potential size of the community solar pilot program or the access of community solar pilot projects to SRECs. Vote Solar has demonstrated that a 450MW pilot program could create 1,778 jobs, provide \$800 million in economic opportunity for New Jersey, and provide clean energy access to over 30,000 customers at very low cost to ratepayers: less than the cost of a postage stamp per month². At the same

² Vote Solar, "Community Solar: Ready to Work for New Jersey" (September 2018). Available at: <https://votesolar.org/usa/new-jersey/updates/cs-pilot-can-create-800-million-dollars-benefits/>

time, GTM Research has demonstrated there is the near-term market potential for 3.3GW of community solar in the state serving 3.6 million customers³. While community solar regulations published in the State Register on February 19th do not specify a 450MW (150MW per year) pilot program, they wisely provide an opportunity to increase beyond the minimum 75MW per year after the first year of the program. Given the cost effectiveness of community solar and the fact that community solar is the only way for the majority of New Jerseyians to directly participate in and benefit from solar, any successor program should not impose SREC targets that limit the growth of the community solar market. Instead of MW targets, SREC factors can allow for more capacity to be deployed at lower cost.

V. CCSA SREC Factors Proposal

The Massachusetts SREC II program structure is a proven model that can be adopted, with modifications, in a short time frame to bring down costs while achieving goals the state has, such as supporting solar projects on rooftops, parking lots, landfills, and brownfields and providing low income customers the ability to lower their electric bills by choosing solar. Note that this factoring approach is in addition to the more expedited factoring of all SRECs envisioned for the interim program for EY 2020, which is simply a uniform reduction across all projects for SREC compensation.

The Massachusetts SREC II program provided fractions (“factors”) of SRECs to each MWh of generation from different projects. Massachusetts used a simple set of four categories of projects (“A”, “B”, “C” and “Managed Growth”). These “sectors” included buckets of different types of projects, such as residential, community solar, landfill sited projects, etc. Sector A projects generated a full SREC for each MWh of generation, Sector B generated nine tenths of an SREC for each MWh of generation, Sector C eight-tenths, and Managed Growth seven-tenths. Using round numbers for ease of example, one can think of Massachusetts SREC II factors working in the following manner: If every type of project each generated 100MWh of generation, “A” sector projects produced 100 SRECs for their 100MWh of generation at the SREC market rate; projects in Market Sector “B” produced 90 SRECs for their 100MWh of generation; and Market Sector “C” projects generated 80 SRECs for their 100MWh of generation, while all other projects in the “managed growth” category generated 70 SRECs for their 100MWh of generation. The Massachusetts Department of Energy Resources (DOER) retained the authority to set the number of MW permitted in the Managed Growth category each year. Note that we are not proposing an exact replication of this program, but instead outline it to describe the basic structure of a factoring approach. In Massachusetts, this structure allowed the state to drive solar development toward policy-preferred project types while supporting a robust and diverse market and ensuring, via the managed growth mechanism, that the market did not become oversupplied.

Similar to the A, B, and C categories employed in Massachusetts, CCSA proposes several categories of project types along with different factors based on modeling performed by Gabel Associates. These categories are envisioned to be combined to account for projects meeting different attributes above and beyond the “Base Factor”, which represents a low-cost, greenfield

³ Greentech Media, “The Vision for U.S. Community Solar”, Executive Summary, p.17. Available at: <http://bit.ly/2JWfKyT>

community solar project⁴ without the incremental costs of different project location and customer acquisition and management costs. The project categories and SREC factors are described in Table 1 below.

As an example of how this factoring approach would work, a community solar project with 50% LMI customers would receive an SREC factor of .31, if that project was also on a roof it would receive an SREC factor of .04 meaning that the project would have a total SREC factor of 0.88 (.31 +.04 + the Base Factor of .53). These factors represent the incremental revenue needed above and beyond the Base Factor. The Base Factor represents a 1 MW ground mounted greenfield project with minimal (10) subscribers. As the factors are a function of the market price, compensation for different project categories changes with the changes in the market price for SRECs.

The factors in Figure 1 below are based on the modeling done by Gabel Associates enclosed as Appendix A. These factors are all for community solar projects, but the same analysis can be done to develop factors for other solar types, such as residential and commercial rooftop systems and grid supply systems. We would expect that BPU would create a factored SREC program inclusive of all market segments.

Note that in practice projects in the Community Solar Pilot Program will be fully residential projects since the bill credit, as defined in the final program rules published in February 19th, will not support non-residential customers on rates with demand charges. Some configurations of these project types is therefore unlikely. Should non-residential customers be viable participants following rule changes or other modifications to the bill credit, it will be important that the Board have in place mechanisms to ensure that there is representative small customer (i.e., residential and small commercial) participation in the program. Factored SRECs could be a way to achieve this goal, but any differentials between SREC factors to support small customer participation must more than cover the cost of small customer acquisition and management to incentivize providers to take on the additional cost.

Figure 1: CCSA Proposed SREC Factors

	Notes	Factor ⁵
Base Factor	This category is intended to be the lowest available SREC Factor and apply to ground-mounted projects that don't meet the criteria in any of the other Factor categories (i.e. greenfield projects that don't meet the criteria in the Customer-based Factors below).	0.53

⁴ As this base factor project assumes no customer acquisition costs, one should assume this project has the minimum 10 subscribers required in the rule. It is important that any SREC factor and the community solar program rules ensure representative participation in the community solar program, including at least 50% small customers.

⁵ assumes current SREC price of \$225/MWh

Customer-based Factors		NOTE: these factors represent incremental revenue above the base factor
Community Solar with 50%+ small subscriptions	Community solar project that has at least 51% of its capacity subscribed by small subscriptions (25 kW or less)	0.22
Community Solar serving 51%+ LMI customers	Community solar project that has at least 51% of its capacity subscribed by LMI customers. ⁶ It is assumed that customer acquisition and management is 25% higher than non-LMI small customers. This factor does not account for financing challenges that should be addressed through consolidated billing nor any costs related to providing higher bill savings beyond those that would be offered to non-LMI customers.	0.31
Siting-based Factors		NOTE: these factors represent incremental revenue above the base factor
Rooftop Projects		0.04
Landfill	As defined by NJ DEP Solar Siting Analysis Dec 2017 pages 10-11	0.53
Brownfield, Historic Fill	As defined by NJ DEP Solar Siting Analysis Dec 2017 pages 10-11	0.40
Canopy	100% of system installed on top of a parking surface or pedestrian walkway in a manner that maintains the function of the area beneath the canopy.	0.75
Advanced Agricultural (Dual Use)	Stakeholders will need to work with relevant New Jersey state agencies to develop rules for a dual-use program. For reference please see MA SMART program Agricultural Solar Tariff Generation Unit Guideline , which outline the requirements to qualify for the ASTGU Adder. ⁷ Revenue needed to support these projects is highly contingent on the requirements created.	0.22

⁶ This definition and subscriber eligibility criteria should be consistent with the Community Solar Pilot Program rules' definition of "LMI community solar project."

⁷ SMART Program Base Compensation Rates and Adder Rates outlined in the "Capacity Block Rate Guideline" available under the "Guidelines" section of the Resources tab on the [SMART website](#).

VI. Responses to BPU Questions in December 26, 2018 Notice:

1) In your direct experience, how has the current SREC program functioned over the past 5 years?

While community solar is new to New Jersey, a number of CCSA members have been active in other solar market segments in the state. Looking at the amount of solar deployed in the state, the SREC program has been a success, but not without volatility.

In addition, SREC program guidelines have been revised to restrict certain types of land use for project siting, restricting and/or limiting larger ground-mount projects (Subsection R) from being eligible for SRECs. We believe the SREC successor program should seek to support a more nuanced land use policy and allow project development across a wide spectrum of markets/project types to help achieve the State's aggressive goals and avoid the boom and bust development cycles seen in the past.

2) How should any proposed SREC Successor Program be organized in conformance with the Clean Energy Act and Staff's SREC Transition Principles? Please provide detailed quantitative and qualitative responses as to the perceived pros and cons of each of the following options: a. a fixed price SREC; b. a market-determined SREC; and c. any other option(s).

CCSA believes that an SREC program with factors for different project types is the way to achieve the principles outlined for a successor program. The basic concept underpinning our SREC factors proposal can work under different constructs- either a fixed price SREC program, a market-determined SREC program, or a non-SREC program which provides capacity-based incentives (such as the California Solar Initiative or New York's MW Block Program).

As noted in the memo outlining how we derived SREC factor proposal (Appendix A), CCSA arrived at factors using an estimate of the revenue needed to make different project types financially viable. Similar exercises have been used in Illinois' Adjustable Block Program⁸ and Rhode Island's Renewable Energy Growth program⁹ to determine compensation levels for projects. Those states use fixed price REC programs. However, the same analysis can be used to support the establishment of SREC factors for a tradeable SREC program, as we propose the BPU adopt.

While a fixed SREC price program can provide stability to the market place, there are significant challenges and risks of delay that come from moving from an established SREC market construct to a program that does not retain the central market-based SREC construct that has been used in New Jersey for years. Massachusetts, for example, took three years to establish and the Solar

⁸ Illinois Adjustable Block Program description available at: <http://illinoisabp.com/about/>

⁹ Rhode Island Renewable Energy Growth Program description available at: http://www9.nationalgridus.com/narragansett/business/energyeff/4_dist_gen.asp

Massachusetts Renewable Target (SMART) program and thereby transition away from its SREC program. This came at the cost of a two-year stall in the market and lost jobs in the industry. For this reason, while CCSA's SREC Factor proposal can be modified to work under multiple SREC successor models we suggest that New Jersey continue to use a market based SREC program.

3) Based on your response to question 2 above, provide precise quantitative and qualitative recommendations as to how your preferred SREC Successor Program model would be implemented, keeping in mind the necessity of satisfying the "SREC Transition Principles" set forth above.

The SREC Successor Program (an "SREC II" program) would include many features of the SREC program currently operating in the state. The Board would set a compliance obligation for the load serving entities and an Alternative Compliance Payment amount. SREC II certificates would be registered in PJM's Generation Attributes Tracking system, in the same way that SREC certificates are registered today.

Projects should be eligible for SREC II certificates for a period of 10 years, consistent with recent Board determinations. As noted in our SREC Factoring proposal, projects would generate SRECs proportionately to their relevant factors.

In order to better balance the market and prevent the booms and busts seen in the market to date, an automatic balancing mechanism should be established, similar to Massachusetts.

4) How should Legacy SRECs be valued? Should these Legacy SRECs be valued under the SREC Successor Program or valued separately?

CCSA, along with other solar parties, envision the Legacy SREC program operating alongside, but separate from, the SREC successor program.

5) How should Pipeline SRECs be valued? Should these Pipeline SRECs be valued under the SREC Successor Program or valued separately? a. Should the Board continue the current SREC program as a separate program? If so, how? b. Should the Board include the current SREC program within the SREC Successor Program? If so, how?

Consistent with the comments made by other solar parties at the BPU, an interim program for "Pipeline" projects should be put in place to be effective for the coming energy year (EY 2020). This proposal should account for the 75MW size of the first year of the community solar pilot program and credit projects at the factors outlined by the Solar Energy Industries Association, i.e., .8 for projects filing SRP applications after June 1st. An interim SREC program should operate as part of the legacy SREC program. This interim program for pipeline projects is distinct from the successor program.

6) For any solar transition, should the Board set a megawatt ("MW") target for annual new solar construction? If so, should those targets be defined as percentage of retail sales or a set MW cap? Under what circumstances and/or assumptions is this target achievable?

The Clean Energy Act of 2018 states that the permanent community solar program should “establish a goal for the development of at least 50 megawatts of solar energy projects per year, taking into account any changes to the SREC program.”¹⁰ Any target in the SREC program should use factoring to deploy community solar at low cost and should account for the 3.3GW 2030 market potential of community solar as outlined in *The Vision for U.S. Community Solar: A Roadmap for 2030*¹¹.

7) In any SREC Successor Program, should the Board seek to set annual MW capacity caps for new solar construction or percentages of retail sales? Why or why not? If yes, what should be the value through 2030 and why? If yes, should the Board seek to set differentiated capacity caps under the solar RPS based on project type?

C.48:3-87 38. d. (3) states that the Board, in the report due to the Governor with 24 months of the Clean Energy Act’s enactment provide a proposal for an SREC transition that “develop[s] megawatt targets for grid connected and distribution systems, including residential and small commercial rooftop systems, community solar systems, and large scale behind the meter systems, as a share of the overall solar energy requirement, which targets the board may modify periodically based on the cost, feasibility, or social impacts of different types of projects.”

Based on this market assessment, the initial pilot year program size of 75MW, and the cost effectiveness of community solar, the community solar target for the successor program should be set at 300 MW per year beginning in energy year 2021.

8) In the SREC Successor Program, should the Board provide differentiated SREC or solar value incentives to different types of projects? Should such differentiated SREC compensation be created through SREC multipliers, through an add-on valuation, or through some other method? Based on what factor(s) should any SREC compensation be differentiated?

Yes. CCSA refers the Board to its factoring proposal described elsewhere in this proposal.

9) How should the cost cap be measured? Should any “head space” under the cost cap in the first years be “banked”? Why or why not?

In meeting the 50% renewable energy standard, the Clean Energy Act of 2018 sets limits on ratepayer impact “so that the cost to customers of satisfying the requirement shall not exceed nine percent of the total paid for electricity consumption by all customers in the State for energy year 2019, energy year 2020, and energy year 2021, respectively, and shall not exceed seven percent of the total paid for electricity consumption by all customers in the State in any energy year thereafter.”

¹⁰ C.48:3-87.11(10) f(2)

¹¹ GTM Research for Vote Solar, “The Vision for U.S. Community Solar: A Roadmap for 2030” <https://votesolar.org/policy/policy-guides/shared-renewables-policy/csvisionstudy/>

Given that any limit is based on a future amount of electricity sales, setting the target either requires forecasting and adjustments to forecasts or the use of historical energy data. This average should include several years and be updated on a rolling basis to smooth out fluctuations in sales from year to year. In years where ratepayer impact is below the statutory impact, the difference in ratepayer expense should be banked to be used in future years. This will provide necessary flexibility to the Board as it implements the Clean Energy Act.

10) Can and should the cost cap be determined based on net costs that include some type of valuation of associated benefits? If so, what should those qualitative and quantitative benefits be and how should they be assigned a value? If the Board can and should consider a net benefits test, should other cost impacts be included? Which ones? Why? If other cost impacts should not be included, why not?

The cost cap should include consideration of benefits of solar generation to offset the cost of the SREC program. CCSA recommends that the Board consider a comprehensive set of energy, environmental, generation capacity, transmission, and distribution benefits; the Rocky Mountain Institute's work on this topic remains an excellent and comprehensive set of benefits to consider in the Board's analysis¹². As noted in our response to Question 12, we believe that New Jersey should undertake a comprehensive review and reworking of distribution system planning as a prerequisite to moving beyond SREC programs and to any successor to net metering. This updated planning and investment paradigm can provide a set of the distribution and transmission values to inform any changes to solar programs and tariffs in the future.

11) What steps should the Board take to implement the cost cap? In particular, please discuss the pros and cons of decreasing the Class I REC Renewable Portfolio Standards. Should any measures implemented differentiate among the different type of Class I renewable energy technologies? Should these measures differentiate among the different market sectors (e.g. utility-scale grid supply versus small residential systems)? Should these measures be technology neutral? Why or why not?

CCSA believes decreasing the Class I market will be unnecessary as a factoring approach and appropriately set ACP can avoid exceeding cost caps. Staying within rate impact limits should be more feasible should the Board bank rate impact headroom from year to year and consider the benefits of solar PV which offset costs.

12) Should the solar industry transition into a true, incentive-free market as the costs of solar begin to approach "grid parity be a goal, or even a consideration, of the SREC Successor Program? If so, how can a SREC Successor Program assist that transition? Should a transition also encompass changes to the net metering program (cf. ongoing FERC/PJM review of DER aggregation)?

CCSA believes over time that the state can transition away from an SREC and SREC successor program. However, sunseting incentives should be based on a quantitative assessment of what it will take to meet the state's clean energy goals and whether policy constructs in place are sufficient to meet those goals. The state has a 50% renewable portfolio standard to be met by

¹² http://www.rmi.org/elab_emPower

2030 and a 100% clean energy goal by 2050; this will come as electricity consumption grows in response to the electrification of transportation, industrial processes and building energy use. The state needs to ensure its solar incentive policies are able to reach the pace and scale of these ambitions.

A longer-term transition should include an examination of successors to net metering as net metering combined with incentive programs are often used as proxies to compensate distributed resources for the full suite of benefits they provide but which are often not quantified. As CCSA noted in its July 31st, 2018 comments on the community solar pilot program, numerous studies on net metered solar in the Northeast have shown the residential retail rate to be a reasonable proxy for net metered solar's value in New Jersey. However, commercial demand charges in New Jersey generally make net metering undervalued and impossible without a viable SREC market for those customers. Indeed, for this reason, CCSA does not believe that the bill credit, as defined by the final Community Solar Pilot Program rules will support the participation of non-residential customers in the pilot. A successor to net metering could overcome some of the challenges that rate design presents to fair compensation for solar generation. However, this effort should not happen in isolation and any transition away from net metering, or a net-metering like tariff, should be based on more systematic changes in distribution system planning and investment.

Any transition away from net metering should be based on a broader effort at rethinking utility distribution planning and investment and provide far greater transparency into distribution system needs which can show the long-term avoided costs provided by solar and other distributed energy resources. Distributed solar not only avoids energy and capacity, it avoids distribution and transmission expenditures. With the addition of energy storage, the ability of solar to reduce grid infrastructure and energy costs in the most constrained hours of the year will be enhanced further.

California and New York have been undertaking reforms to their distribution system for five years now and their work remains ongoing. With 7 gigawatts of net metered solar generation, California has to date retained net metering. New York transitioned larger projects to the Value of Distributed Energy Resources (VDER) tariff but has provided for a transition credit as it works to finalize the underlying methodology for valuing the resources, a process which remains ongoing. The work of changing utility planning and investment practices is critical to improving the integration of distributed energy resources going forward, but the experience in these other states shows that New Jersey should undertake such efforts with significant lead time given the scale and scope necessary for these efforts.

13) Please provide comments on any significant issues not specifically addressed in the questions above, making specific reference to their applicability in the New Jersey context. Please do not reiterate previously made comments.

In addition to the comments on how the SREC market should be structured, there are some procedural changes needed to the SRP application to make the SREC program able to accommodate community solar programs. Specifically, the SRP applications should be modified

to include a community solar option which requires acceptance into the Community Solar Pilot Program (or the permanent program to be developed in 2021) rather than execution of a contract with a customer as community solar projects are typically subscribed as they near completion.

VII. Conclusion

CCSA appreciates the Board and BPU Staff's consideration of these comments and look forward to engaging in the working groups planned for this spring to develop an SREC successor program and, hopefully, the development of an interim SREC program in the near term. Please do not hesitate to contact me with questions at (978) 869-6845 or brandon@communitysolaraccess.org.

Sincerely,

Brandon Smithwood
Policy Director
Coalition for Community Solar Access

**APPENDIX A:
GABEL ASSOCIATES SREC FACTOR ANALYSIS**



Memorandum

To: Brandon Smithwood
Policy Director, CCSA

From: Pamela Frank, VP; Isaac Gabel-Frank, VP; Ashley-Lynn
Chrzaszcz, Associate

Date: March 1, 2019

Subject: SREC Factoring Analysis for CCSA

Introduction

Gabel Associates, Inc. (Gabel) has been retained by the Coalition for Community Solar Access (CCSA) to provide analysis to support CCSA's stakeholder comments in discussions regarding the future of New Jersey's solar market. CCSA is interested in exploring a solar renewable energy certificate (SREC) factoring approach that would support the different types of solar projects the state would like to incentivize for development.

Given New Jersey's dense development and the limitations on open space for solar, projects with a more expensive cost structure, such as arrays sited on landfills and brownfields, and solar canopies over parking lots, may need larger incentives and support in order to reach a target return on investment (ROI). This is reflected in a fractional percentage of the SREC.

This memo summarizes Gabel's analysis of the minimum SREC values required to meet certain return thresholds for development. It provides the methodology and assumptions used by Gabel to calculate the required SREC prices to develop viable solar projects.

Methodology

CCSA identified eight types of solar projects for analysis: rooftop, landfill, brownfield, canopy, advanced agricultural, and green fields, which was used as the Base Factor (i.e. base case). Additionally, projects built on green fields with 50% low and moderate income (LMI) and projects built on green fields with 50% non-LMI were also analyzed.

Assumptions

These scenarios were modeled by Gabel by utilizing average values observed in real projects across New Jersey as well as data provided directly by CCSA. Installation costs were based upon actual average installed values noted in the New Jersey solar market for each project type. To control variables in this exercise, we assumed all projects were 1MW and used appropriate data accordingly. We recognize that larger projects are likely to afford greater economies of scale which may allow for lower SREC values for some project types.

Projects were assumed to produce 1,300 kWh per kW of capacity, which is in line with the expected yields of new, efficient panels. We assumed an Investment Tax Credit (ITC) of 10% to reflect a conservative and forward-thinking value, which will be available to projects in the future.

Several customer assumptions were made for various project types. The subscription rate (i.e. the per-kilowatt-hour rate for customer community solar subscriptions) was equal to 85% (a 15% discount) of the average residential electricity rate for public utilities in New Jersey, yielding a \$0.136/ kilowatt-hour rate. In addition, customer acquisition costs were only assessed for the Base Factor + 50% LMI and Base Factor + 50% Non-LMI scenarios to clearly reflect the marginal impact of acquiring and managing low-income customers. We note that the LMI projects only assumed additional costs for customer acquisition, billing and management and therefore the proposal does not address the financeability of the projects nor any additional savings beyond 15% customers may be expected to be provided.

The assumption matrix used for this analysis can be found in Appendix I.

Results

Based upon the solar financial analysis inclusive of the assumptions discussed above, the Base Factor has an SREC break-even value of \$120. This means that clean green field projects require a minimum SREC value of \$120 to be economically viable. All other scenarios require proportionally greater SREC values to support economic viability.

The following table illustrates the fractional ratio of an SREC when compared to a base factor (clean, green field) solar system, as well as the SREC value, for each project type. To demonstrate the factors below, we use the current SREC market price of \$225¹. The factors are based on the incremental cost of different projects above and beyond the base factor project as a function of the SREC market price.

¹ Current price as of 2/28/2019, via SREC Trade https://www.srectrade.com/srec_markets/new_jersey

Table #1: Fractional Ratios and SREC Values by Project Type

	Base Factor (Clean Green Fields)	Base Factor (Clean Green Fields + 50% Non-LMI)	Base Factor (Clean Green Fields + 50% LMI customers)	Rooftop Projects	Landfill	Brownfield, Historic Fill	Canopy	Advanced Agricultural (Dual Use)
SREC Value	\$120.00	\$170.00	\$190.00	\$130.00	\$240.00	\$210.00	\$290.00	\$170.00
Incremental Revenue Need Above Base Factor	N/A	\$50.00	\$70.00	\$10.00	\$120.00	\$90.00	\$170.00	\$50.00
Fractional Ratio	0.53	0.22	0.31	0.04	0.53	0.4	0.75	0.22

These results imply the following SREC needs under several scenarios:

1. A project on a greenfield site with 50% small subscribers would require a total SREC factor of 0.84 (i.e., .53 Base Factor plus .31 Small Customer Factor).
2. A project on a landfill with minimal subscribers (10 subscribers) would require a total SREC Factor of 1.06 (i.e., .53 Base Factor plus .53 land fill factor)
3. A project with 50% LMI customers and sited on a landfill would require a total SREC Factor of 1.37 (i.e., .53 Base Factor plus .31 LMI factor plus .53 landfill factor), and additional incentive to support financing of the project.

Gabel is available to provide additional scenarios or sensitivity analyses at the request of CCSA.

Appendix I

Assumption Matrix utilized by Gabel Associates for the Analysis

Category	1	2	3	4	5	6	7	8
	Rooftop Projects	Landfill	Brownfield, Historic Fill	Canopy	Advanced Agricultural (Dual Use)	Base Factor (Clean Green Fields)	Base Factor (Clean Green Fields + 50% Non-LMI)	Base Factor (Clean Green Fields + 50% LMI)
System Size (kW)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
System Production (kWh/year)	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000
In Service Date	1/1/2021	1/1/2021	1/1/2021	1/1/2021	1/1/2021	1/1/2021	1/1/2021	1/1/2021
Avg Installation Cost (\$/watt)	\$2.000	\$3.100	\$2.800	\$3.500	\$2.500	\$2.050	\$2.050	\$2.050
Subscription Rate (\$/kWh)	\$0.1360	\$0.1360	\$0.1360	\$0.1360	\$0.1360	\$0.1360	\$0.1360	\$0.1360
Land Lease (\$/year)	\$30,000	\$15,000	\$15,000	\$15,000	\$15,000	\$15,000	\$15,000	\$15,000
Customer acquisition	\$0	\$0	\$0	\$0	\$0	\$0	\$150,000	\$187,500
PPA Esc. (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PPA Period (years)	20	20	20	20	20	20	20	20
SREC Period (years)	10	10	10	10	10	10	10	10
SREC Esc. (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O&M Cost (\$/kW)	\$15.00	\$15.00	\$15.00	\$15.00	\$15.00	\$15.00	\$40.00	\$50.00
O&M Cost Esc. (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Insurance Cost (% Install Cost)	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%
Insurance Cost Esc. (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Decommissioning Reserve (\$/watt/year)	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
ITC Value (%)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Debt Allocation (%)	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Debt Term (years)	7	7	7	7	7	7	7	7
Discount Rate/Cost of Debt (%)	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.50%	7.50%