Aida Camacho-Welch

Secretary of the Board

New Jersey Board of Public Utilities

PO Box 350

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RE: Stakeholder Comments for New Jersey Solar Transition Staff Straw Proposal

Comments Submitted by:

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Please accept the following comments along with supporting spreadsheets in response to the Stakeholder Request for Comments. Flett Exchange has operated an electronic exchange for New Jersey solar credits since 2007. Over 8,000 solar owners sell their SRECs and over 20 electricity companies procure those SRECs on our market. We track the progress of the SREC market and advise investors and energy companies on current and future value and supply and demand of the SREC market.

1. **How has the New Jersey SREC market functioned in the past 5 years:**

   EXCEEDED THE RPS:

   The New Jersey SREC market was responsible for the State of New Jersey achieving the RPS according to law at prices significantly lower than the cost caps as set out in law. During the years 2014 to 2016 the SREC market enabled the State to achieve 94% to 99% of the RPS and it over performed the RPS by 112% to 133% (tab2 H3 H8) bringing the benefit of solar quicker to the residents of New Jersey.

   Solar Installations grew by 115% in the last 5 years from 1,254 Mw installed in 2014 to 2,701 (tab2 E3-E8) at the end of 2018 at an average rate of 289 Mw a year (www.njcep.com solar installation report). This exceeded the RPS so much that new solar legislation was needed in 2018 to adjust for the exceedance of the RPS at a lower than expected cost to the ratepayer as set out in 2012 legislation.

SIGNIFICANT SAVINGS TO THE RATEPAYER DUE TO SPOT MARKET

During the 5 year time frame of 2015 to 2019 the average daily spot price was an average of 29% lower than the SACP (Tab3 P8 – P12). The cost savings to the ratepayer from a freely traded SREC market was $975,429,438 (Tab1 G-18) over the 2015 to 2019 timeframe (less the losses absorbed by the ratepayer for fixed rate long term contracts that the BPU required EDC's to enter into during 2009 to 2012 and pass losses to the ratepayer which extend for 10 years)

SAVINGS ATTRIBUTED TO FUTURES AND OVER-THE-COUNTER MARKET

The futures market for NJ SRECs are traded on the Intercontinental Exchange (ICE). The settlement prices for future delivery of SRECs for the next seven energy years 2020 to 2026 are trading at a 42% discount to the SACP (Tab1 F8 – F15). This is a robust market and allows solar developers and electricity suppliers to hedge future commitments. Open interest for regulated futures contracts on ICE for energy year 2020 is 477,910 SRECS, energy year 2021 is 547,760, and energy year 2021 is 382,790 (www.theice.com) which represents 15% of the RPS for each year. The forward market on the over-the-counter market is larger than the futures which implies that at least 30% and as high as 50% of the SREC market is hedged out to 2021 on forward bilateral contracts between willing counterparties and not the ratepayer. The savings estimate referred to above attributed to the discount below the SACP for spot transactions to the ratepayer is actually significantly higher when taking into account the futures hedges and the bilateral OTC market all executed significantly below the SACP. Forward contracts that were freely entered into by commercial participants were all at lower prices since the futures market in New Jersey SRECs has always traded in a backwardation (forward prices at discounts to current prices). All of the mandated long term contracts entered into by the EDC's by the direction of the BPU were all done at a flat price which deviated from the freely traded market and created a wind-fall arbitration opportunity for solar developers who took advantage of them.

FIXED RATE CONTRACTS INCREASED RATEPAYER COSTS AND CREATED WINDFALL PROFITS FOR DEVELOPERS

The two significant factors that increased costs in the New Jersey SREC market during the past 5 years were the EDC fixed rate contracts/loan programs and the 2018 solar legislation.

Fixed rate EDC contracts/loan programs required EDC's to enter into fixed rate 10 year SREC contracts and in the case of PSE&G territory required a loan and fixed rate contract for solar installations. All of these long term contracts were done at high prices and are now at significant losses to the ratepayers. Each year the EDC's must sell the contracted SRECs at a loss and pass the losses on to the ratepayer. Due to confidentiality rules it is impossible to calculate the exact losses because the contract prices are not published. Losses were significant in that a few hundred thousand SRECs are auctions off each year and some of these contracts were done at a fixed price of $450/year which at current prices results in losses of over $220/SREC to the ratepayer.

The 2018 legislation increased costs to the ratepayer by fixing demand and limiting competition for all of the "legacy" 5.1% for approximately 110,000 solar installations. (Tab1 M8 – M15) This law removed all benefits of competition and efficiency that flow over to cost savings by the ratepayer for these legacy projects by separating them from all new solar being developed after the 5.1%.

2. **How should any proposed SREC Successor Program be organized in conformance with the Clean Energy Act and Staff's SREC Transition Principles?**

We Suggest a Market Determined SREC

Fixed price SREC or tariff model increases costs: The pro for a fixed price SREC program is that it guarantees profits for solar developers at the expense of the ratepayer. This is evidenced by all of the EDC fixed rate programs created and administered by the BPU in the past. All of the contracts entered into by the BPU resulted in significant losses by the ratepayer compared to projects compensated by the freely traded SREC. Solar Cost reductions were significant during the past decade and will most likely continue to decrease in the future. Locking ratepayers into fixed long term contracts increases costs and reduces the ability to achieve more solar at a lower cost for the state of New Jersey. Now with cost caps instituted in the legislation the long term contracts jeopardized solar industry job growth because long term contracts are paying for uneconomical legacy solar projects. (Some EDC fixed price contracts are still being paid out at $450/MWh).

Market Determined SREC: Flett Exchange suggests a market determined SREC model. A market determined SREC model best aligns the interests of both ratepayers and solar owners. The market based SREC market in New Jersey has saved ratepayers hundreds of millions of dollars and has exceeded RPS goals consistently over the past decade. (Tab1 K4 – K8) It is a familiar tool used by the current solar investors in New Jersey. To maintain the advantage of a market determined SREC model SACP levels must be addressed as costs reduce and RPS levels need to be increased as solar gets deployed quicker than modeled. A market based model is the most efficient and cost effective way to drive down solar costs and achieve and potentially exceed RPS goals.

Implementation of SREC Successor Program: Maintain the same competitive SREC model as in the past in that there is one SREC for all legacy transition and new solar. This keeps interests aligned with solar investors and solar developers. Successful competitive programs to build out solar rely on long-term increases in solar development which creates the demand side of the market. An RPS schedule of 6% solar by 2030 will accomplish this (including SREC retirements the actual percentage of solar will be close to 9%). The SACP needs to be decreased to keep solar costs under the legislatively mandated 9% and 7% cap. A suggested RPS and SACP is attached. (Tab 4 Column G and Q)

Legacy SREC Price Valuation: If the successor program is modeled after the current successful program of one SREC market for legacy and new projects then all SRECs are valued based on supply and demand somewhere between $0 and the SACP. If a separate SREC program is established for Successor SRECs then the BPU will periodically have to reduce the SACP for legacy SRECs to ensure that the ratepayer does not pay more than the 7% cap for the legacy

SRECs and any amount for all of the successor projects developed. It is calculated that based on a 13 cent per kilowatt hour retail rate with state-wide retail electricity consumption in the 74 Gwh range the payments for the successor program will have to be capped over $100 below the current SACP in the $150 range BEFORE taking account for any payments to finance any projects in the Successor program. This is modeled to happen in 2021 or sooner depending upon the Successor program costs which are expected to kick in in late 2019 when the 5.01% cap is hit for the legacy SREC program

3. **Our recommended Successor Program model would retain one SREC class for all legacy, pipeline and successor solar Projects**

   One freely traded SREC market would continue the successful solar program that has existed for over a decade in New Jersey. To comply with the cost restraints imposed by the 9% and 7%, along with implementing a long range solar build–out schedule of 300 Mw/ year (this slightly exceeds the last 5 year average build rate of 289 Mw / year Tab 2 E3-E8) the following RPS (Tab4 column G) and implied SACP (Tab 4 Column Q) would accomplish this. New Jersey would obtain close to 10% solar (including retirements) under the cost caps with this approach. This approach satisfies all of the SREC Transition Principals listed in the Straw Proposal.

   This would require that the BPU institute a $7 ACP for Class 1 RECs. The SACP could be raised if the Class 1 component trades below $7. (This may also require an increase in the net metering cap which may need an act of legislation.)

   Details and calculations are on the accompanying spreadsheet however, here is the implied SACP to stay under the cost caps and RPS to maintain a 300 Mw/year build out for one unified SREC incentive for all legacy, pipeline and successor projects. (See Tab 4 for details)

EY	RPS%	Implied SACP
2021	5.18	$203.83
2022	5.59	$141.26
2023	5.97	$132.21
2024	6.29	$125.48
2025	6.49	$106.56
2026	6.41	$107.76
2027	6.17	$111.98
2028	6.26	$110.44
2029	6.27	$110.16
2030	6.37	$91.95
2031	6.45	$90.96

4. **How Should Legacy SRECs be valued?**

   If one SREC market is used for a legacy, pipeline and successor value would be based on supply/demand between $0 and the implied SACP (tab4 column Q) for all.

5. **How Should Pipeline SRECs be valued?**

   If one SREC market is used for a legacy, pipeline and successor value would be based on supply/demand between $0 and the implied SACP (tab4 column Q) for all.

6. **Should the Board set a Mw target for any new solar construction?**

   Based on historical build rates in New Jersey 300 Mw per year slightly exceeds the past 5 year average of 289Mw per year. (See Tab2 column E)

7. **Should the Board set an annual Mw capacity cap?**

   The board should not set any annual caps and let the competitive market develop for the majority of solar projects with exceptions for non-net metered projects. The freely traded SREC market value gives market signals and weeds out uncompetitive, high priced solar projects based on supply and demand. Based on past experience the Board should restrict SREC qualification of non-net metered projects of multi Mw size and develop a mechanism in which projects which are not net metered and larger than 2.5 Mw join a waiting list. The BPU can throttle the issuance of SRECs if there is an unintended consequence that would cause these projects to be detrimental to the long-term healthy development of the New Jersey solar development process as a whole.

8. **Should the Board provide differentiated SREC or solar value incentives to different types of projects?**

   We suggest that if any differentiation is given it should only be in a partial issuance of SRECs not additive. The SREC is a currency that represents 1,000kwh of electricity generated by solar. The energy measurement component of the currency is universal across the traded spectrum by state and also in the design mechanism of the databases that track and mint SRECs. Our suggestion is to regulate the issuance of SRECs of a project by only allowing a percentage of the project to generate SRECs and allow the remainder of the project to generate the lower valued REC. For instance, if it is determined that 3Mw community solar projects do not need full SREC compensation then allow 2Mw of the project to mint SRECs and allow the other 1Mw to mint RECs. This would be a valuable throttle mechanism. An additive model runs counter to industry practice.

9. **How should the cost cap be measured? Should any "head space" under the cost cap in the first years be "banked".**

   We feel that the cost cap – which will act as a de-facto SACP/ACP – is intended to protect the ratepayer. The new concept or recent conversation in relation to New Jersey renewables of "head space" and "banking" implies that the area under the cap is a "budget" to be paid by the ratepayer to owners of solar and out-of-state class 1 facilities. The area under the cost cap is the savings passed along to the ratepayers as a result of all the competitive forces of developers and competitive electric suppliers. If the cost cap is a budget then the incentive would be for SREC buyers to pay the SACP which would get refunded back to their customers.

10. **Should the cost cap be determined based on net costs that include some type of valuation of associated benefits?**

    Net benefits tests are extremely complicated and their values are highly subjective. There is a time and a place for these types of values to be introduced however, in all likelihood at this time in relation to solar development in New Jersey we feel that the financial incentives available are sufficient enough to attain the RPS set out by legislation. The legislation set a clear 9% and 7% cap and if net benefits were to be included to charge a higher $ amount to the ratepayer the legislation would have indicated that in our opinion.

11. **What steps should the Board take to implement the cost cap?**

    To reduce the risk of exceeding the cost cap of 9% and 7% the Class 1 ACP of $50 must be lowered. We believe this can be done by BPU and does not have to rely on a law change since the BPU set the $50 ACP to begin with. We suggest an ACP of $7 for Class 1. (See Tab 4 Columns N, O, and P). Even with this decrease New Jersey will be sending almost $300 million a year by 2030. If it is not decreased and Class 1 RECs trade up to the current ACP of $50 all of the money will go out of state by year 2022 and all current and most legacy solar projects will not receive any payments. (Tab 4) In addition to lowering the ACP for Class 1 the BPU will need to lower the SACP for legacy solar as well to stay below the cost caps. In energy year 2022 when the cost cap moves from 9% to 7% to maintain the financing of the current solar development pace of 300 Mw per year and a Class 1 REC payment of $7 payments to all of the legacy SREC projects and projects built after the 5.1 % is achieved cannot exceed $141.26 each (Tab 4, Q6)

12. **Should the solar industry transition to a true, incentive-free market?**

    As solar development costs continue to fall we believe ratepayers should pay less. New Jersey has made adjustments in the past in reducing ratepayer impact as solar prices dropped quicker than any mainstream estimates. However, just as importantly, New Jersey should maintain demand for SRECs to keep the investors whole and avoiding a collapse in SREC prices for legacy projects. Due to the numerous factors outside of New Jerseys' control, it is unlikely that investors will invest in solar in any meaningful way in New Jersey without some type of "adder" such as the SREC. This is clear when comparing solar development in New Jersey with other states that do not offer a state specific incentive.