STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program	))))))	**REPLY COMMENTS OF THE PUBLIC STAFF REGARDING THE APPLICATION OF THE SOLAR INTEGRATION SERVICE CHARGE**

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission, by and through its Executive Director, Christopher J. Ayers, and respectfully submits the following reply comments in response to the Commission's October 7, 2019, *Order Requesting Comments* ("October 7 Order") in the above-referenced dockets regarding the application of the Solar Integration Service Charge ("SISC") in the context of the Competitive Procurement of Renewable Energy Resources ("CPRE") Program pursuant to N.C. Gen. Stat. § 62-110.8(b)(2). On October 18, 2019, the following parties filed initial comments: Duke Energy Carolinas, LLC ("DEC"), and Duke Energy Progress, LLC ("DEP") (collectively "Duke"); First Solar, Inc. ("First Solar"); the North Carolina Clean Energy Business Alliance ("NCCEBA") and the North Carolina Sustainable Energy Association ("NCSEA"); and the Public Staff. In addition, the CPRE Independent Administrator, Accion Group ("IA"), also filed initial comments.

I. Comments on Supplemental Notice of Decision

The Public Staff in its Initial Comments set forth its position on whether, and how, the SISC should be applied to Tranche 2 of the CPRE Program. The Public Staff had developed their position prior to the Commission's October 17, 2019 *Supplemental Notice of Decision* ("*SNoD*"), and noted that it planned to address any changes or clarifications in these reply comments.[1]

In its Initial Comments, the Public Staff stated its position that the SISC should be considered in Tranche 2 of the CPRE; it should be fixed for the life of the CPRE contract; it should be assessed on all solar bidders (including utility projects) as a separate charge within the PPA, and not as a decrement to the avoided cost cap; and that solar generators should include their assumptions regarding their ability (or inability) to mitigate the charge into their bid price ("Initial Proposal"). This solution was designed to support the timely and cost-effective implementation of the CPRE Program, while also balancing the value of providing better cost certainty to potential market participants with the need to provide incentives to solar generators to reduce their volatility. Overall, most of the Public Staff's Initial Proposal is consistent with the *SNoD*, particularly the suggestion that the SISC be fixed over the life of the CPRE contract. However, in light of Ordering Paragraph No. 7 requiring DEC and DEP to include the SISC in its avoided energy costs, the Public Staff recognizes that there is a conflict with its Initial Proposal to assess the SISC as a separate charge within the CPRE PPA.

[1] Public Staff Initial Comments at 2, footnote 2.

The Public Staff believes that the decisions reached in the *SNoD* primarily apply to projects selling their power to Duke under PURPA standard offer and negotiated contracts. The Public Staff views Ordering Paragraph No. 13 of the *SNoD* as the Commission recognizing that it retains sufficient discretion and flexibility regarding how the SISC is applied to non-PURPA contracts, such as the CPRE Program, to allow the Public Staff's Initial Proposal to still be appropriate in the CPRE context. Therefore, it remains the Public Staff's position that the most efficient method of including the SISC in the CPRE cost-effectiveness evaluation is to fix the charge for the duration of the contract term, and to require all solar bidders to pay the SISC unless they can demonstrate that they have materially reduced their site's volatility. Bid prices would be inflated to include the SISC (or the bidders' assumptions about their ability to mitigate the charge[2]), thus ensuring that the SISC is considered in the statutorily mandated cost-effectiveness requirement for CPRE projects.

A central feature of this proposed solution is that there is no up-front determination, by Duke or the IA, of whether a solar facility can or will operate as a controlled or uncontrolled solar generator for the entirety of its contract.[3] All solar bidders are assumed to be "uncontrolled" and are assessed the SISC; there is no need for the IA to consider the SISC in its evaluation, and the risk of whether a

[2] For example, a bidder may find it most advantageous to install a battery and use it to perform price arbitrage in the winter season, where there is a high price differential between premium peak and off-peak hours; while in the shoulder and summer seasons, there may be more value in using the battery to reduce volatility. Their bid price would reflect these operational assumptions.

[3] "Controlled" and "uncontrolled" have the meaning here defined in the Stipulation of Partial Settlement between DEC, DEP, and the Public Staff, filed May 21, 2019 ("SISC Stipulation").

solar facility does not reduce volatility during any time in its 20-year term falls on the bidder, and not on ratepayers. The proposed "Solar Site Volatility Metric" and the monthly measurement and verification proposed in Exhibit 11 of the *pro-forma* PPA filed on October 15, 2019, requires that solar sites seeking to mitigate the SISC to verify monthly that they have reduced their volatility.[4] Not only does this eliminate the need for the IA to make highly technical judgements as to whether a bidder who declares their intention to mitigate the SISC is able to,[5] but it also eliminates the need to create contractual language and set financial penalties in the *pro-forma* PPA in the event that a bidder who bid in as a controlled solar generator does not reduce their volatility during any measurement period throughout its 20-year contract.[6]

With this in mind, the Public Staff proposes an alternative solution for the Commission's consideration, should it determine it is appropriate to also apply Ordering Paragraph No. 7 to the CPRE Program ("Alternative Proposal"). This proposal is similar in that the SISC would be fixed for the life of the contract and that all solar bidders would be assumed to operate as an "uncontrolled" solar generator. The difference is that the bid price would not reflect the imposition of the SISC, and bid prices would be compared against an avoided cost cap that has

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[4] The Public Staff has some remaining concerns with the reporting mechanism proposed by DEC and DEP in Exhibit 11, but will address any concerns with the Tranche 2 *pro-forma* PPA in separate comments, as appropriate.

[5] On page 2 the IA's Initial Comments, they describe in Paragraph 3 and 4 the challenges that having to evaluate whether a project was sufficiently designed to allow it to reduce or eliminate the added ancillary service costs over a 20-year term would raise, and that excluding the SISC from the cost-effectiveness evaluation would reduce some of these challenges.

[6] In DEC and DEP's Initial Comments, they raise the possibility that a controlled solar generator might have a battery malfunction, which causes them to fail to reduce volatility for a given time period (at 12). This, or any other unforeseen issues with reducing volatility, are likely inevitable over a 20-year contract.

been reduced by the SISC.[7] If a solar generator is certified in any given month to have reduced its volatility (i.e., operated as a "controlled" solar generator), it would receive a payment on their bill equal to the applicable SISC multiplied by the number of megawatt-hours ("MWhs") produced in that month. This additional payment would reflect the value that solar generator provided Duke's system by reducing its volatility, and would theoretically be equal and opposite to the reduction in fuel costs incurred by Duke due to that solar facility's less-volatile operations. The bidder would then include its assumptions about its ability to mitigate the SISC in its bid; if the bidder believed it would receive additional revenue over and above its bid price by reducing its volatility, it could subsequently *reduce* its bid price for energy and capacity, thus making that project more competitive relative to uncontrolled solar projects, and more likely to fall below the reduced avoided cost cap.

To illustrate how both the Initial and Alternative Proposals would ensure that bids remain below avoided cost, a simplified walkthrough is presented in Table 1 below.

[7] The reduced avoided cost cap would only be applicable to solar projects; all other renewable energy bidders would be evaluated against the higher avoided cost cap.

Table 1: Hypothetical Pricing Walkthrough for CPRE Tranche 2 Proposals. All figures in $/MWh.

	Initial Proposal		Alternative Proposal	
SISC (DEC as example)	$1.10		$1.10	
20-Year Avoided Cost	$35.00	*Energy + Capacity*	$35.00	*Energy + Capacity*
Avoided Cost Cap Used in CPRE	$35.00	*Does not include SISC*	$33.90	*Avoided energy reduced by SISC*
"Uncontrolled" Solar Bid	$34.10	*Includes SISC - assumes bidder includes 100% of SISC in bid*	$33.00	*Does not include SISC*
Monthly SISC Charged	$1.10	*Appears as charge on bill*	$0.00	*No charge*
Total Payment	$33.00	*Bid less SISC*	$33.00	
Uncontrolled Decrement to Avoided Cost Cap	$0.90	*Avoided cost cap - bid*	$0.90	*Avoided cost cap - bid*
"Controlled" Solar Bid	$33.00	*Lower than uncontrolled due to mitigation assumptions*	$31.90	*Lower than uncontrolled due to mitigation assumptions*
Monthly SISC Waived	$0.00	*SISC not charged*	$1.10	*Appears as credit on bill*
Total Payment	$33.00		$33.00	*Bid + SISC credit*
Controlled Decrement to Avoided Cost Cap	$2.00	*Avoided cost cap - bid*	$2.00	*Avoided cost cap - bid*

In the Public Staff's Initial Proposal, the avoided cost cap (nominally $35/MWh) is not reduced by the SISC, but the bid price (nominally $33/MWh) is assumed to be *increased* by the SISC for an uncontrolled solar generator who knows they will be charged $1.10/MWh. Therefore, the decrement to avoided cost for an uncontrolled solar generator is $0.90/MWh (avoided cost cap minus bid). For a bidder that intends to operate as a controlled solar generator, they would not include the SISC in their bid under the assumption they would be able to waive the charge; their decrement to avoided cost would therefore be $2.00/MWh. Should the bidder, in any given month, fail to mitigate volatility, the risk of that failure is on them and not the ratepayer.

The Alternative Proposal, which is admittedly more complex and is being proposed in the event that the Commission determines that the SISC should be incorporated into the avoided energy cost used to calculate the avoided cost cap for Tranche 2 of the CPRE, is also presented. In this case, pursuant to Ordering Paragraph No. 7 of the *SNoD*, the avoided cost cap is reduced by the SISC to $33.90/MWh. A bidder who does not intend to mitigate the SISC would bid their nominal price of $33/MWh, without increasing the bid to include the SISC. Thus, the decrement for that uncontrolled solar generator bid is $0.90/MWh, which is the same as in the Initial Proposal.

A controlled solar generator would be compared to the same reduced avoided cost cap as any other bidder; however, based on their assumptions that they will be able to mitigate the SISC and receive additional revenue for doing so, they would *reduce* their bid by the SISC to $31.90/MWh. This makes them more competitive relative to uncontrolled solar bidders, with a decrement of $2.00/MWh – which is the same decrement a controlled solar generator had in the Initial Proposal. Once again, the risk that this facility would not reduce its volatility, and not receive the additional revenue from reducing its volatility, is entirely on the bidder and not the ratepayer.

From a ratepayer perspective, these two alternatives should achieve the same result. Ultimately the total cost for a controlled versus an uncontrolled generator is the same to ratepayers, and the SISC is ultimately paid by ratepayers. The key to both approaches is that the incentive, and risk, to mitigate the SISC now lies with the party most capable of actually reducing the facility's volatility.

Overall, the Public Staff believes its Initial Proposal is more straightforward and increase transparency to market participants.[8] The Alternative Proposal is submitted in these reply comments in order to provide the Commission with an option that achieves the same results in a manner that is more consistent with the proposed application of the SISC to standard offer avoided cost PPAs pursuant to the *SNoD*.

II. Comments of Other Parties

A. Duke Joint Comments

Duke noted that applying the SISC to solar generators participating in Tranche 2, as well as future CPRE Tranches, was consistent with the findings of the *SNoD* and the Stipulation entered into between the Public Staff and Duke.[9] The Utilities also generally supported the Public Staff's Initial Proposal to apply the SISC as a fixed charge based on the average cost of the "Existing Plus Transition" level of solar, and requiring solar facilities bidding into CPRE to account for the SISC in developing their bids, as opposed to applying the SISC as an input into the CPRE cost-effectiveness evaluation process. Duke noted some of the challenges associated with making assumptions about a CPRE's ability to reduce intra-hour volatility in each hour over a 20-year term, and stated that it believes maintaining the SISC as a charge (as opposed to inclusion in the avoided cost cap) is the optimal approach for CPRE purposes "because it provides appropriate

[8] To the Public Staff's knowledge, North Carolina is the only state in which an integration charge assessed on intermittent resources can be waived by operating the resource in a particular way. As such, it is not likely that market participants have any significant experience with reducing their volatility in order to avoid such a charge.

[9] Duke Initial Comments at 9-10.

compensation that is tied to actual, as-measured reduction in volatility and provides future flexibility for solar generator owners that are able to demonstrate actual reductions in volatility."[10] This approach is consistent with the Initial and Alternative approaches proposed by the Public Staff.

B. First Solar

First Solar stated that is generally aligns and supports the joint comments filed by NCCEBA and NCSEA finding that the application of the SISC is inconsistent with N.C. Gen. Stat. § 62-110.8, and recommended that the Commission consider alternatives to the SISC to allow the utilities greater control over the operational capabilities of solar generators that bid into the CPRE Program in order to reduce the need for additional ancillary service requirements.[11]

First Solar indicated that the application of the SISC frustrated the legislative direction for operational flexibility, and that the Commission should instead require the utilities to contract with solar generators to agree to dispatch, operate, and control the facilities in a manner with how the utilities dispatch, operate, and control their own generating resources.[12] First Solar further stated that the inclusion of the SISC in CPRE bids results in higher bid prices, and is likely to result in higher prices for ratepayers.

In support of its position, First Solar discussed its position that solar facilities are highly controllable and, if incentivized properly by the utilities, can also provide

[10] Duke Initial Comments at 13.
[11] First Solar comments at 3-4.
[12] First Solar Comments at 5.

ancillary and balancing services that will lead to lower overall costs for consumers.[13] First Solar referenced its earlier comments filed in this docket on March 22, 2019, in which it described the flexible dispatch services that inverter-based renewable resources can provide, and recommended that the Commission make modifications to the PPA and operational changes in CPRE Tranche 2 to take advantage of these capabilities. These earlier comments also formed the basis for one of the topics discussed at the Commission's May 23, 2019 technical conference to evaluate modifications to the CPRE Tranche 2 RFP.

In its March 22, 2019 comments in this docket, and reiterated at the technical conference, the Public Staff indicated its general agreement that a dispatchable contract like that proposed by First Solar, under which Duke would operate the facilities as if they were their own resources, and provide the developer a monthly payment proportional to the facility's capacity and availability during that month, may be in alignment with the intent of N.C. Gen. Stat. § 62-110.8 and reduce risk to ratepayers.[14] We noted, however that there still remained some uncertainty with regard to the ability of each utility to recover the costs of PPA that were not based on energy produced. In its July 2, 2019, *Order Modifying and Accepting CPRE Program Plan* ("July 2 Order"), the Commission found that it was premature to approve the use of a dispatchable PPA proposed by First Solar for Tranche 2 purposes, but directed Duke, the IA, the Public Staff, and the market participants to continue discussions on these matters.[15]

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[13] First Solar Comments at 7.
[14] March 22, 2019, Comments of the Public Staff on the Interim CPRE Program Plans, at 16-17.
[15] July 2 Order at 17.

In general, the Public Staff agrees with First Solar that one of the key components of the CPRE Program is to allow the utilities the ability to dispatch, operate, and control the procured resources. Recognizing that, to the extent the SISC, and the ability to mitigate it by operating as a "controlled solar generator", provides a price signal, we support the bidders to be able to operate the system flexibility based on the price signals provided in their bids, in order to maximize their revenue, but also providing the most value to customers.

As stated by the Commission in the *SNoD*, there is no dispute that DEC and DEP are incurring increased intra-hour ancillary service costs as a result of integration of solar facilities into the DEC and DEP Systems. Consistent with the Solar Ancillary Service Study conducted by Astrapé, the Public Staff agrees that as solar penetration increases, the associated volatility on Duke's system will increase ancillary service costs. The Public Staff agrees with First Solar that to the extent CPRE Program assets create specific integration challenges, they should have the first opportunity to provide solutions to those challenges, rather than simply leaning on existing utility assets.[16] Bidders should therefore be incentivized to design their facilities to operate in ways that reducing the volatility, such as adjustments to DC to AC ratios, inverter settings, the incorporation of storage, and other mechanisms that may help them be considered a "controlled solar generator." The Public Staff believes that the proposed application of the SISC, as well as the opportunity to mitigate the application of the SISC to their projects as provided in the Public Staff's Initial Proposal and Alternative Proposal, helps

[16] First Solar Initial Comments at 9-10.

provide a price signal to CPRE bidders to accomplish these goals in a way that minimizes risk to customers.

With regard to First Solar's recommendation that Duke require bidders to submit hour-ahead forecasts in 15-minute increments, the Public Staff does not take issue with this recommendation, but is uncertain as to the added value and functionality of the added hourly forecasting to Duke on an operational basis. In addition, the consideration of this information may be difficult to incorporate into the cost-effectiveness model for these systems, and may also ultimately require the IA and/or Duke to make somewhat subjective evaluations of the operational capabilities of proposed projects as part of the cost-effectiveness evaluation, which may be difficult to implement in a transparent fashion.

C. Joint Comments of NCCEBA and NCSEA

In their joint Initial Comments, NCCEBA and NCSEA found that based on the *SNoD*, the ancillary services costs incurred by Duke due to solar generation should be included in its avoided energy rate, not as a separate charge, and will therefore be already included in the CPRE cost-effectiveness cap for market participants. NCCEBA and NCSEA argued that market participants should not be required to pay both an SISC Charge and also have a lower CPRE Market Cap applied.[17] The Public Staff finds these concerns to be misplaced, since no party has proposed that the SISC be applied as both a charge and as a reduction to the CPRE Market Cap. Further, the Public Staff believes that its Initial and Alternative

[17] Joint Initial Comments of NCCEBA and NCSEA at 8-10.

Proposals ensure that the integration costs reflected by the SISC would only be applied to a participating solar project at most one time, and that through its ability to mitigate these costs as a controlled solar generator, the project may be able to avoid the costs altogether.

NCCEBA and NCSEA also expressed concern that the application of a variable or uncapped SISC would potentially reduce the cost-savings that might otherwise result from the CPRE Program, since market participants would increase their bids to capture the risk associated with changes in the SISC.[18] The Public Staff agrees with these concerns, and consistent with the *SNoD*, the Public Staff's Initial and Alternative Proposals would utilize a fixed SISC amount to provide better cost certainty to market participants.

NCCEBA and NCSEA further noted that the CPRE Program may form the basis for a potential market for incorporation of ancillary services such as regulation and reserves.[19] The Public Staff agrees that, to the extent these costs can be incorporated into the energy, capacity, and renewable attributes that the utilities are obligated to procure from renewable energy facilities under the CPRE Program, these facilities can provide added benefits to ratepayers and help reduce overall system costs. In its March 27, 2019 reply comments in the Sub 158 Proceeding, the Public Staff noted that the Astrapé Study may provide a mechanism to help quantify some of these ancillary services that may be provided by qualifying facilities ("QFs"), noting that "as volatility is minimized or perhaps

[18] *Id.* at 11.
[19] *Id.* at 14.

even eliminated by innovative QFs, the need for the utility to collect the full solar integration charge from such a facility should also be considered."[20] For purposes of CPRE Tranche 2, the Public Staff believes that allowing controllable solar generators to reduce their volatility, consistent with the *SNoD* and the Public Staff's Initial and Alternative Proposals, will provide some incentive to innovative projects and also help provide information over time as to the capabilities and resources to provide ancillary services.

NCCEBA and NCSEA also stated that the control and dispatch rights called for in N.C. Gen. Stat. § 62-110.8 "evidences a statutory intent to offset utility concerns regarding solar intermittency."[21] NCSEA states that these rights should count towards the calculation of any solar integration charge, since they likely help to offset the potential for over-generation and related curtailment issues. The Public Staff notes that the curtailment and dispatch rights included in the CPRE pro-forma PPAs do provide flexibility to address system reliability events such as excess energy situations or ramping concerns, as well as to provide some basis for economic dispatch. The Public Staff does not, however, agree with NCCEBA and NCSEA that the curtailment and dispatch provisions adequately address the additional ancillary service costs associated with intra-hour volatility caused by intermittent solar resources to reduce the applicability of the SISC to CPRE Market Participants.

[20] March 27, 2019 Reply Comments of the Public Staff in Docket No. E-100, Sub 158, at 23-26.
[21] Joint Initial Comments off NCCEBA and NCSEA at 15.

Further, NCCEBA and NCSEA cites the discretion given to the utilities in determining the location and allocated amount of the competitive procurement in N.C. Gen. Stat. § 62-110.8(c) as providing evidence of "legislative intent for Duke to utilize the CPRE Program in such a way as to limit or eliminate extra ancillary service costs. There is no doubt that the General Assembly intended to allow Duke the ability to account for and reduce or eliminate ancillary service costs."[22] The Public Staff notes that the SISC was calculated separately for each utility, taking into consideration solar penetration levels and the current utility portfolio. Therefore, the Public Staff finds that the consideration of the applicable SISC for each utility in the bid prices submitted by CPRE market participants, as proposed in the Public Staff's Initial and Alternative Proposals, is consistent with this legislative intent.

Lastly, NCCEBA and NCSEA cite a recent Ninth Circuit case as evidence that the application of an avoided cost decrement such as the SISC to renewable facilities is barred when the procurement of those facilities is mandated by statute.[23] The Public Staff finds that NCCEBA and NCSEA's reliance on this case is misplaced and not applicable in North Carolina in the context of the CPRE Program. In *Californians*, the Ninth Circuit found that under PURPA, "when a state has a requirement that utilities source energy from a particular type of generator,

[22] *Id*. at 17-18.
[23] *Id.* at 18-19, discussing *Californians for Renewable Energy v. Cal. PUC,* 922 F.3d 929 (9th Cir. 2019).

‘generators with those characteristics constitute the sources that are relevant to the determination of the utility’s avoided cost for that procurement requirement.’”[24]

In the *Californians* case, the court found that if a utility is using renewable energy purchased from a QF to help comply with the state’s renewable portfolio standard, then the utility must calculate avoided costs based on the energy sources that would also meet the RPS. That is not the case here in North Carolina for the CPRE Program. While N.C. Gen. Stat. § 62-110.8(a) does direct DEC and DEP to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW, the procurement mandate was subject to several specific limitations, with the most important being the limitation in N.C. Gen. Stat. § 62-110.8(b)(2) that caps each utility’s procurement obligation “by the public utility's current forecast of its avoided cost calculated over the term of the power purchase agreement.” The statute further provides that “[t]he public utility's current forecast of its avoided cost shall be consistent with the Commission-approved avoided cost methodology.” This linkage of the utility’s Commission-approved avoided cost methodology, which is technology or resource agnostic, to the cost-effectiveness limitation for the CPRE procurement is a key distinction between the situation described in *Californians* and the CPRE Program in North Carolina. In the case of the CPRE Program, if the added integration costs associated with the procurement of solar energy resources increased the overall cost of the resources above the utility’s avoided costs, then the utilities would be prohibited from

[24] *Californians,* 922 F.3d at 937, quoting Cal. PUC., 133 F.E.R.C. 61,059, 61,267.

selecting those resources under the CPRE Program. NCCEBA and NCSEA seem to disregard this critical distinction in their analysis.

WHEREFORE, the Public Staff respectfully requests that the Commission take the foregoing reply comments and recommendations into consideration.

Respectfully submitted, this the 29th day of October, 2019.

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CERTIFICATE OF SERVICE

I certify that a copy of these Reply Comments has been served on all parties of record or their attorneys, or both, by United States mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 29th day of October, 2019.

Electronically submitted
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