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	))))	**COMMENTS OF THE PUBLIC STAFF ON THE INTERIM CPRE PROGRAM PLANS**

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission, by and through its Executive Director, Christopher J. Ayers, and respectfully submits the following comments in response to the Commission's *Order Requiring Interim CPRE Program Reports, Allowing Interim Implementation of CPRE Program Plans, and Establishing a Schedule for Filing of Comments* dated December 17, 2018 (December Order), and the *Order Granting Extension of Time* dated February 1, 2019, requiring the Public Staff to file comments on the CPRE Program plans filed with the Commission on September 1, 2018, in Docket No. E-100, Sub 157.

<u>Background</u>

On November 27, 2017, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (together, Duke), filed a petition for approval of its proposed joint Competitive Procurement of Renewable Energy (CPRE) program. The proposed program plan included CPRE guidelines with a CPRE Program RFP Solicitation timeline. Section 2.3 of the CPRE guidelines estimated that Tranche 1 of the RFP solicitation would be issued in May of 2018. Duke committed to further evaluate and adjust the schedule as needed in future CPRE Program plans.[1]

On February 21, 2018, in its *Order Modifying and Approving Joint CPRE Program* (February Order), the Commission agreed with Duke and the Public Staff that the proposed timeline was reasonable and would remain open to adjustments in the timing of future RFP Solicitations in its review of Duke's future CPRE Program plans and guidelines.[2]

On July 10, 2018, pursuant to Commission Rule R8-71(f)(2)(i), the Independent Administrator (IA) of the CPRE Program transmitted to the market participants the final documents to be used in the Tranche 1 CPRE RFP Solicitation. By that transmittal, the IA opened the Tranche 1 CPRE RFP Solicitation response period and established September 11, 2018, as the deadline for submission of proposals.

On July 30, 2018, in Docket No. E-100, Sub 101, Duke filed a Motion for Approval of CPRE-Related Modifications to North Carolina Interconnection Procedures (NCIP). On August 10, 2018, the Commission issued an *Order Scheduling Hearing, Requesting Comments, and Extending Tranche 1 CPRE RFP Solicitation Response Deadline* that established October 9, 2018, as the new deadline for responses to the Tranche 1 CPRE RFP Solicitation.

[1] CPRE Program Plan, Attachment 1, Initial CPRE Program Guidelines, November 27, 2017, at 2.
[2] February Order at 18.

On September 5, 2018, in Docket No. E-100, Sub 157, Duke filed updates to their Competitive Procurement of Renewable Energy Program Plan, as part of their 2018 biennial integrated resource planning (IRP) reports. Due to the delay in Tranche 1, Duke updated its timelines for future tranches of the CPRE RFP Solicitation and stated, due to the increased estimates of transition megawatts, there may not be a need for a fourth tranche. These changes are reflected in the revised CPRE RFP solicitation schedule in Duke's CPRE Program Plan filed in the IRP.[3]

On October 5, 2018, in Docket Nos. E-100, Sub 101, E-2, Sub 1159, and E-7, Sub 1156, the Commission issued an *Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP* (October Order). Among other things, that Order allowed parties to file comments related to the timing of consideration of potential changes to the administration of the CPRE Program.

On November 5, 2018, Duke filed a letter in response to the Commission's request for comments. In its letter, Duke committed to work with the IA to identify "lessons learned" from the Tranche 1 and to provide the Commission with interim reports on a schedule detailed in the letter. The Public Staff also filed comments on November 5, 2018, in support of the reporting requirements proposed by Duke.

In the December Order, the Commission found cause to allow Duke to implement the CPRE Program plan filed with its 2018 biennial IRP filing in Docket

[3] DEC 2018 Integrated Resource Plan, filed on September 5, 2018; Attachment 2, CPRE Program Plan, at 255.

No. E-100, Sub 157 on an interim basis while the Commission receives comments on that plan. The December Order required the Public Staff to file initial comments on the CPRE Program plans filed with the Commission in the Companies' IRPs by January 31, 2019. Furthermore, the Commission stated that these comments may also address or respond to the interim reports required by the December Order.

On January 31, 2019, the Public Staff filed a motion requesting that the Commission grant an extension of time to allow the IA to host two meetings with all the market participants, Duke, and the Public Staff for the purpose of discussing lessons learned from Tranche 1 and soliciting comments for the Tranche 2 RFP documents. The Commission granted the extension of time for the filing of initial comments until March 22, 2019, and encouraged the parties to work to reach consensus on the issues prior to the issuance of the Tranche 2 RFP Solicitation.

The first CPRE market participant meeting was held on February 22, 2019. The second meeting was held March 6, 2019. All market participants were invited to participate via the IA's website and the meeting was available to attend by webinar. The Public Staff participated in the meetings and the issues addressed in the comments below were discussed in the IA-hosted stakeholder meetings. On March 15, 2019, the IA filed its Report of the Independent Administrator – Tranche II Stakeholder Process (IA Stakeholders' Meeting Report) with the Commission detailing the stakeholder meetings and discussing areas of consensus and non-consensus among the participants.

The Public Staff submits the comments below on the CPRE Program Plans and other issues identified by the Commission and the stakeholders.

Cost Recovery of Grid Upgrades and Bid Refresh

In its October Order, the Commission stated that it will consider several potential revisions to the CPRE rules prior to the issuance of Tranche 2 including whether to: (1) change the CPRE program plan to remove the ability of Duke to recover grid upgrade[4] costs in base rates; (2) change the CPRE program plan to require the initial bid to contain all of the Interconnection Customer's costs;[5] and (3) revise the CPRE process to allow competitive bidders to refresh their bids based upon the assessment of grid upgrades identified in Step Two of the CPRE RFP bid evaluation process.[6] In its October Order, the Commission noted that at the September 24, 2018, oral argument held in this docket, several parties stated that grid upgrade costs may increase after system impact study sometimes more than 20%.[7]

With regard to issues identified by the Commission above, the Public Staff notes that changing the CPRE construct at this time to not allow for the recovery of grid upgrade costs allocated to winning bids in base rates may create additional challenges for implementation of the CPRE Program in an efficient manner. While

[4] The Public Staff uses the term "grid upgrades" to refer to transmission network and distribution upgrades required to interconnect the facility, but not the cost of the interconnection facilities between the generation facility and point of interconnection. This term inclusive of both "network upgrades" and "distribution upgrades," as those terms are defined in the NCIP.
[5] The Public Staff notes that in Tranche 1, the market participants were required to include the estimated interconnection facilities costs in their bids, but not the grid upgrade costs.
[6] October Order, at 12-13.
[7] Id. at 12.

the Public Staff shares the concerns of the Commission regarding potential increases in upgrade costs in the future as projects go from system impact study phase to facilities study phase, requiring the bidders to include grid upgrade costs in their bids may result in additional complexity as market participants would need to refresh their bids to account for any upgrade costs identified during the bid evaluation. Providing for a refresh would require a rulemaking proceeding that could result in additional delays the issuance date for Tranche 2.[8]

Notwithstanding the concern for delay, it is unknown at this time whether Tranche 1 was successful in identifying and screening for projects with little to no upgrade costs.[9] If the imputed costs of system upgrades has resulted in certain projects not being cost effective in Tranche 1, and projects with no upgrade costs were most competitive, then the RFP is working as anticipated. In addition, better locational guidance, as discussed below, can guide market participants towards projects that will require little to no upgrade costs in Tranche 2.

An additional concern identified by the IA with regard to using a bid refresh in the cluster study process is the potential for the refresh process to result in an endless loop as allocated costs change and projects are eliminated and others added as part of that process.[10] If a cluster of projects is studied in accordance with the current Step Two of the bid evaluation process by the T&D sub team and

[8] R8-71(f)(3) provides a process for the evaluation and selection of CPRE bid proposals that proceeds in two steps (Step One and Step Two) and does not include a bid refresh.
[9] According to the November 5, 2018, responses to Commission questions filed by Duke, the Step 2 evaluation of the Competitive Tier of projects from Tranche 1 is scheduled to be completed and winning market participants notified on or about March 25, 2019. The final report on Tranche 1 of the RFP is not expected to be filed until April or May of 2019.
[10] IA Stakeholders' Meeting Report, at 6.

at the time to refresh bids a project withdraws from the RFP due to the system upgrade costs, that would then lead to re-study and re-allocation of upgrade costs that may lead to further bid withdraws. In addition, bid refreshes that significantly alter the ranked order of proposals could result in grid upgrade costs being re-allocated among a different set of projects, thus requiring additional rounds of bid refreshes.

The Public Staff shares the concern that requiring bidders to include costs and allowing for a refresh to account for those costs may result in "cascading" grouping studies requiring multiple refreshes.

Discussion of this topic during the stakeholder meetings indicated that it could hinder the ability of some developers to participate in the CPRE if the upgrade costs allocated to winning bids are not recovered by the utilities in base rates. Concerns voiced by market participants include:

- Certain market participants may enter low bids they do not intend to develop to ensure their project is selected for the Competitive Tier, only to wait until upgrade costs are known and they are able to refresh their bids.
- Market conditions, such as solar module prices or construction contracts, are constantly changing for the solar PV industry. If a bid refresh is allowed, all participants should be afforded the opportunity to refresh their bid to consider market conditions, and not only the Competitive Tier.

- Unknown grid upgrade costs will lead to less accurate bids, as they may be inflated to account for the uncertainty.

Further, the Public Staff notes that whether winning bidders pay for grid upgrades in their project price or the utility pays for grid upgrades and includes it in base rates, the difference to ratepayers is minimal.[11] There may be benefit in choosing the methodology which results in a simpler RFP and evaluation process, which would be socialization of the grid upgrade costs for winning bidders and no bid refresh, as utilized in Tranche 1. Under either approach, the grid upgrade costs allocated to each bid would be included in the bid price ensuring that the most cost-effective bids are selected and remain below avoided costs.

While there is a risk to ratepayers of grid upgrade costs being underestimated in the evaluation phase of the RFP, the Public Staff believes that better locational guidance, as discussed below, may help mitigate the risk by steering market participants to areas of the grid with minimal or no upgrade costs. The Public Staff notes that until the results of Tranche 1 are known, it is difficult to speculate on whether there will be substantial costs associated with grid upgrades required to interconnect winning bids.

<u>Grid Locational Guidance</u>

In its October Order, the Commission stated that it would explore options for Duke to more specifically direct generators to locations on the system that will

[11] Under the socialization approach currently in use, the cost of grid upgrades reflect the utility's cost of capital and authorized rate of return. Under a scenario considered by the Commission, the cost would reflect the winning bidder's financing costs and profit margin.

not involve major network upgrades.[12] Duke indicated in the February 22, 2019, IA-hosted stakeholder meeting that it will continue to refine the maps as the date for issuance of Tranche 2 RFP Solicitation documents approaches, but no specific details were shared.

Generally, the Public Staff supports more detailed maps or guidance to direct market participants to areas where there is existing capacity and projects are not likely to trigger significant upgrade costs. Maps or lists of feeders and substations with available capacity would allow market participants to select projects from their portfolios to bid into CPRE that are more likely to avoid or face lower grid upgrades, thereby helping to reduce the uncertainty regarding potential upgrade costs.

However, some market participants voiced concerns at the February 22 meeting that locational guidance that is too specific might lead to inflated land prices and burdensome local regulatory activity in anticipation of solar development. Other developers indicated that more specific data would aid in business planning, highlighting that striking the right balance between specificity and generalization must be considered in developing the appropriate level of locational guidance for Tranche 2 purposes.

The Public Staff notes that Duke is required to direct market participants to areas where costs are minimized. Pursuant to House Bill 589, the Companies have

[12] October Order, at 12-13.

the authority to determine the location and allocation of resources to reduce costs to utility customers:

> . . .[T]he electric public utilities shall have the authority to determine the location and allocated amount of the competitive procurement within their respective balancing authority areas, whether located inside or outside the geographic boundaries of the State, taking into consideration (i) the State's desire to foster diversification of siting of renewable energy resources throughout the State; (ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and (iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as nondispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs. [13]

Pursuant to the statutory authority cited above, the Public Staff believes it is appropriate for Duke to develop and publicize revised locational guidance that improves upon provided for Tranche 1 of the CPRE. This guidance should reflect, to the extent possible, the impact of projects which will be interconnected to Duke's system as a result of CPRE Tranche 1, as well as other changes to the State and FERC-jurisdictional interconnection queues (both projects entering the queue and being withdrawn) since Tranche 1 began.

Energy Storage

According to the IA's Second Status Report, in Tranche 1 of the CPRE, there were four total proposals with energy storage (three in DEC and one in DEP)

[13] N.C. Gen. Stat. § 62-110.8(c).

out of 78 total proposals. The Competitive Tier consists of 34 proposals in DEC, three of which have energy storage; and 16 proposals in DEP, none of which have energy storage.[14] The IA has indicated that the bids with storage operated the storage devices to maximize revenue – that is, energy storage was discharged during the on-peak hours and charged during the off-peak hours, both derived from the E-100, Sub 148 Option B rate tariffs used in the RFP. The Public Staff notes that due to the broad on-peak hours defined in Option B, which do not accurately reflect Duke's current highest production cost hours, it is unlikely that energy storage operation using those on- and off-peak hours will maximize the benefits to the ratepayer.

Market participant discussions regarding energy storage during the two stakeholder meetings were robust and informative.[15] First, market participants and Duke generally agree that energy storage can provide many grid benefits, such as frequency regulation, operational reserves, and firm capacity. However, there is no mechanism to pay market participants for these services. The only way for a market participant to utilize energy storage in Tranche 1 was to either use it to capture curtailed energy or to engage in energy arbitrage by charging during off-peak hours and discharging during on-peak hours. One developer compared this to "using a Swiss Army knife only for the corkscrew." Energy storage promises many grid benefits but if future CPRE Tranches do not attempt to quantify their

[14] E-100, Sub 101, CPRE IA Second Status Report, filed December 21, 2018, at 1.
[15] IA Stakeholders' Meeting Report, at 2, 6-7, 11, 15.

value and compensate developers for them, they will never be realized by ratepayers.

Second, the question of what party has operational control and dispatch rights over the energy storage was raised. This is related to the issue of ancillary services; Duke would essentially need operational control over the energy storage in order to maximize those services, yet this could result in reduced value of these resources to the market participant by changing the energy output profile to no longer align with the on-peak hours, operate at a reduced energy output to maximize frequency regulation benefits or other ancillary reserves, or potentially operating the energy storage system in a way that reduced its operational life, thus making their deployment less likely. This is a complex and challenging issue, and successful resolution may require significant modifications to the pro forma PPA to resolve. No solutions were presented or discussed at the stakeholder meetings.

Finally, the market participants stated that operational restrictions contained in the Energy Storage Protocol ("Protocol") within the pro forma PPA were an issue when seeking financing. Duke did make limited changes to the Protocol in response to feedback before the issuance of Tranche 1, including modifying language giving Duke the right to unilaterally change the terms at any time, and modifying the ramp rate restrictions. Market participants called particular attention to Item 8 of the Protocol, in which Duke must commit to providing the next day's bulk discharge window by 4:00 p.m. of the current day. Market participants felt that this limited their solar facility's ability to fully capitalize on bulk energy discharge, as 4:00 p.m. is approaching the tail end of a solar facility's daily output profile.

Specific recommendations to improve the Protocol were not presented or discussed at the stakeholder meetings.

Areas of agreement with respect to energy storage were related to energy price granularity and the transparency of the IA's evaluation methodology. With more granular pricing, the developer could more accurately tailor their energy storage to meet the needs of the grid. In addition, market participants expressed some confusion during these meetings when discussing how bids were ranked by the IA. If market participants were more aware of the methodology used by the IA, and in particular the use of a "net system benefits" metric to rank each proposal, bids with energy storage could both maximize their value to the developer and their value to the grid.

While the selection of three energy storage bids may indicate that some market participants have found a way to make these projects cost-effective at rates below Duke's avoided cost, it is likely that more robust discussions focused solely on energy storage are needed to realize the full potential within the context of the CPRE Program. It is the Public Staff's hope that Duke and the market participants continue to evaluate energy storage and attempt to reach agreement on how the value of energy storage can be quantified in future Tranches. As recommended in earlier comments, the Public Staff continues to believe that a technical conference or separate stakeholder process, focusing exclusively on energy storage[16] may

[16] See Comments of the Public Staff in Response to Joint Motion of NCSEA and NCCEBA in Docket No. E-100, Sub 101, at 6.

help resolve many of the complex and technical issues related to the operation and compensation of energy storage.

Transparency

The issue of transparency was briefly raised in the stakeholder meetings, particularly as it relates to project evaluation, post-Step One project rankings, and how winning and losing bids are treated in the interconnection queue. The Public Staff believes that the CPRE RFP process should be as transparent as possible, particularly with respect to the evaluation methodology. As market participants were not fully informed as to how their bids would be evaluated, there was no opportunity for them to alter their facility's characteristics, or invest in energy storage, to maximize their proposal's net benefit to the grid.[17] Some participants requested that the project rankings after Step One be released. However, the Public Staff tends to agree with the IA that this information would not provide a significant benefit to the process prior to the winners being announced. It would be appropriate and helpful for the IA to release an appropriately anonymized post-Step One project ranking along with the winning bids, so that market participants and other interested parties can understand how imputed project costs affected the proposal rankings.

[17] The net benefit to the grid was calculated by subtracting the projected hourly system marginal cost from the proposal's bid price in that hour and multiplying the result by the hourly output profile submitted with the bid. This was done for each hour over the 20 year term, and the resultant "net system benefit" was used to calculate each project's net present value (NPV). Projects were ranked according to their NPV.

Curtailment

The matter of curtailment provisions in the pro forma PPA was the subject of debate between the market participants and Duke. There is general consensus that the 5% to 10% "free" curtailment provisions[18] in Tranche 1 (Curtailment Maximum) resulted in bid prices that are higher than they otherwise would be, as market participants factored into their pricing assumptions that they will be curtailed up to the Curtailment Maximum. This curtailment risk is therefore reflected in each bid. Market Participants raised the concern that this provision would ultimately end up costing ratepayers more, particularly if facilities were not curtailed up to the Curtailment Maximum. At the same time, the Curtailment Maximums were based on limits initially established in negotiated QF PPAs to provide flexibility to the utilities to address system reliability events, not based on an efficient level of curtailment for economic dispatch purposes. As solar penetration increases over time, the Curtailment Maximums may not accurately reflect the most cost-effective amount of dispatch control that the utilities need to operate their system in a cost-effective fashion, and the 20-year terms do not provide flexibility to adjust these levels.

[18] The pro forma PPA authorized the utilities to issue Control Instructions or take actions to dispatch down the facilities, without any additional compensation to the sellers, equating to 5% in DEC and 10% in DEP of the annual expected output of energy (MWhs) that the facility would have generated, but did not as a result of the Control Instructions. If this annual threshold (5% or 10%) is exceeded, the PPA then provides that seller would be compensated at the full contract price for each MWh of energy that could have been generated but was not due to the dispatch down or Control Instruction. These Curtailment Maximums did not include curtailment of the facility during "Emergency Conditions" or "Force Majeure" conditions, for which compensation would not be provided.

Consensus on the best way of resolving this uncertainty was not found during the stakeholder meetings. Several concepts were raised as possible solutions, including:

1. No curtailment: Duke could only curtail these facilities in system emergencies, similar to existing qualified facilities under PURPA.
2. Full payment for curtailment as a service: projects would be paid full price for every MWh that is curtailed.
3. Partial payment for curtailment as a service: projects would be paid some fraction of their full bid price for every MWh that is curtailed.
4. Fixed monthly payment with unlimited curtailment: Duke could operate these facilities as if they were their own resources, while the developer would receive a fixed monthly payment that is proportional to their facility's capacity and availability during that month.

The Public Staff has concerns with full payment for all curtailed energy as it may result in higher costs to consumers. House Bill 589 requires third party bidders to "commit to allow the procuring public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generation resources."[19] This provision clearly requires a significant level of control over the operation of facilities procured through the CPRE.

The Public Staff believes the fixed monthly payment option raised by market participants in the stakeholder meetings has the potential to satisfy the intent of

[19] N.C. Gen. Stat. § 62-110.8(b)

House Bill 589 and reduce the risk borne by ratepayers; however, it may present some uncertainty with regard to the ability of each utility to recover the costs across jurisdictions. That is, if it were approved in North Carolina by the Commission for DEC and DEP, it would also have to be approved in South Carolina. The Public Staff would like to explore the option in further discussions with market participants and the utilities to understand the benefits of this approach and any delay it may cause to seek the necessary approvals to provide the utilities with sufficient certainty for cost recovery of PPAs that are not based on energy in kWhs produced.

In its February Order, the Commission indicated that it was "not prepared to approve NCCEBA and NCSEA's alternative methods of dealing with curtailment and compensation on this record, but will monitor this issue and remain open to changes in the future, as is further discussed below in the context of considering the pro forma PPA."[20] The Public Staff believes that it is appropriate for the Commission to carefully consider any changes to the pro forma PPA that other interested parties may file in this proceeding with regard to defining the limits and compensation for resource dispatch and curtailments.

Modification of RFP Documents

In its February Order, the Commission stated that Duke's proposed pro forma PPA was approved for use in the Tranche 1 CPRE RFP solicitation only and ordered Duke to continue its discussions with NCCEBA, NCSEA, the Public Staff,

[20] February Order, at 26.

and other interested parties regarding potential revisions to the pro forma PPA.[21] In its May 11, 2018, Notice of Posting of CPRE Tranche 1 RFP, Duke stated that it worked with NCSEA and NCCEBA and incorporated specific revisions to the PPA it deemed to be appropriate.

In addition to the changes made by Duke prior to the issuance of the Tranche 1 RFP, the Public Staff believes it is appropriate for the Commission to review and approve the pro forma PPA for Tranche 2 considering any additional changes that may be appropriate, specifically with regard to the energy storage protocol and defining the limits and compensation for resource dispatch and curtailments.

In the stakeholder meetings, the market participants requested that asset acquisition contracts should be reviewed and approved in the same manner as the pro forma PPA.[22] The Public Staff continues to maintain the position that only the pro forma PPA must be approved by the Commission.[23] While the Public Staff has not reviewed the asset acquisition agreements at issue, we understand that the market participants continue to be concerned by non-price terms set out in those agreements and hope the IA will work to identify and facilitate agreement between

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[21] Id., at 15-16. The Commission stated:

> Duke's proposed pro forma PPAs are approved as filed for use in the Tranche 1 CPRE RFP Solicitation only, and the Commission will require Duke to continue discussions with the Public Staff, NCCEBA, NCSEA, and other interested parties with the goal of reaching consensus on the provisions of the pro forma PPA for future CRPE RFP Solicitations.

Id. (emphasis added).

[22] IA Stakeholders' Meeting Report, at 3,10.

[23] Comments of the Public Staff Response to Joint Motion NCCEBA and NCSEA, June 20, 2018, at 4-5.

market participants and Duke to revise any terms that may be perceived as commercially unreasonable.

RFP Solicitation Schedule

In Docket No. E-100, Sub 157, Duke's biennial IRP, the Companies present an updated procurement schedule for the CPRE. Specifically, the issuance date for Tranche 2 is delayed to July 2019 and Tranche 3 is moved to July 2020. Additionally, Tranche 4 is eliminated entirely as Duke estimates that the transition megawatts will result in a procurement of less that the initial target of 2,660 MWs. This new schedule puts the end of the procurement, not including any Green Source Advantage rollover, at month 40 of the statutorily mandated 45-month procurement window.

While the Public Staff believes that the timeline presented in the IRP is reasonable and will result in procurement within the statutorily required timeframe of 45 months, it may also be prudent to consider delaying Tranche 2 and the entire CPRE Program Plan until the avoided cost rates proposed in Docket No. E-100, Sub 158 (Sub 158 Proceeding) are approved by the Commission.

In the avoided cost docket, the Public Staff is proposing more granular pricing periods that will allow compensation hours when capacity need is greatest and when energy storage is most valuable. The proposals made in Tranche 1 were in the form of a decrement to the Schedule PP Option B avoided cost pricing structure. That structure only provides three pricing periods: summer and non-summer capacity and energy on-peak and energy off-peak, and the bid decrement had to be equal in each of the pricing periods. The Public Staff is currently proposing nine energy pricing periods in the Sub 158 Proceeding, including shoulder seasons and premium peak hours.[24] The market participants agreed that more pricing periods would be preferable for Tranche 2.[25]

The Public Staff believes that the elimination of Tranche 4 gives Duke and the IA more flexibility in timing to delay the issuance of Tranche 2 if there is a compelling reason for the delay.[26] A delay for the purpose of implementing more current avoided cost rates in the Sub 158 Proceeding would better incentivize energy storage bids, and it would also ensure that those projects procured under Tranche 2 are not being compensated under rates and hours that are no longer reflective of the utilities' current and projected avoided costs. The more granular rates would provide clear price signals to developers as to when their energy and capacity is most valuable to the grid, which would incentivize bids to provide more value to ratepayers. Other matters being disputed in the Sub 158 Proceeding, including the fuel forecast methodology, hedging benefits, PAF calculation, and others would also have an impact on the cost-effectiveness cap for CPRE market participants. In particular, the solar integration charge proposed in the Sub 158 Proceeding should be resolved to remove uncertainty regarding its applicability,

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[24] Public Staff Initial Statement and Exhibits, E-100, Sub 158, February 13, 2018, at 56.
[25] IA Stakeholders' Meeting Report, at 2.
[26] While the Public Staff believes there is sufficient time to complete the procurement in the 45-month window, we also note that N.C. Gen. Stat. § 62-110.8(h)(5) directed the Commission to adopt rules to establish "… a procedure for the Commission to modify or delay implementation of the provisions of this section in whole or in part if the Commission determines that it is in the public interest to do so." This provision was adopted by the Commission in Rule R8-71(i)(2) and provides the Commission with an important safeguard to ensure that the CPRE Program is implemented in accordance with the public interest.

the specific amount of the charge, and whether it will be refreshed biennially as proposed by Duke.

During the February 22, 2019 stakeholder meeting, the IA sought feedback on the delay to implement the Sub 158 avoided cost rates. Market participants indicated they were open to a modest delay but overall seemed to oppose any substantial delay for the issuance of Tranche 2 and indicated that their reticence to delay the CPRE significantly was due to cost factors. As future tranches are delayed, some projects will not be eligible for the full federal investment tax credit (ITC).[27] In addition, developers pointed to the carrying costs of projects, such as costs of land contracts, which increase materially with longer delays. In addition, some parties mentioned limits on local government zoning and construction permit approvals that may have to be extended or renewed if projects are delayed considerably, adding additional cost and uncertainty. Some developers were open to a modest delay to implement more granular rates.

The Public Staff believes that evaluating CPRE projects based on the most current avoided cost methodology is in the best interest of ratepayers and may help to resolve other challenges including the proper compensation for energy storage in Tranche 2. However, if the Commission determines that the delay required to resolve all issues in the Sub 158 Proceeding would result in too significant a delay for market participants, it may be possible to incorporate some

[27] The Federal ITC is currently 30% for projects beginning construction by December 31, 2019; it will decline further over time to: 26% for projects beginning construction by the end of 2020; 22% for projects beginning construction by the end of 2021; and 10% for all projects that begin construction in 2022 and beyond.

components of the changes being proposed in the Sub 158 proceeding, such as the utilization of more granular pricing periods proposed by the parties, provided that agreement can be reached on those pricing periods in a reasonable timeframe.

Conclusions

In summary, based upon its review of Duke's CPRE Program Plan and IA status reports, and its participation in CPRE Stakeholder meetings, the Public Staff makes the following recommendations:

- It is appropriate to allow the utilities to continue to recover the grid upgrade costs allocated to winning bids through base rates and not modify the CPRE Program to include a bid refresh process.
- Duke should provide more detailed and updated grid locational guidance, reflecting the addition of Tranche 1 resources and other changes in its interconnection queues, which will direct market participants to areas of the grid with capacity to accommodate new facilities and are less likely to require major grid upgrades.
- In the interest of transparency, it is appropriate to require the IA to release a suitably anonymized post-Step One project ranking along with the winning bids.

- It is appropriate to require Duke and the IA to provide a more full and complete description of the bid evaluation methodology prior to Tranche 2.

- It is appropriate that additional changes to the pro forma PPA should be presented to the Commission for approval prior to Tranche 2. Changes proposed by Duke and commented on by intervenors should address the energy storage protocol and curtailment procedures, limits, and compensation.

- That a technical conference or stakeholder process focusing on energy storage has merit and should be considered.

- It is appropriate to utilize the avoided cost rates and methodology from the Sub 158 Proceeding for Tranche 2 purposes, even if this potentially results in a delay of Tranche 2 and successive tranches of the CPRE Program. In the alternative, if certain elements of the Sub 158 proceeding, such as the more granular pricing periods can be agreed to by the interested parties and approved by the Commission, prior to the issuance of Tranche 2, those elements should be used for Tranche 2 purposes.

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

Respectfully submitted this the 22nd day of March, 2019.

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CERTIFICATE OF SERVICE

I certify that a copy of these comments have 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 22nd day of March, 2019.

Electronically submitted
/s/ Layla Cummings