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April 1, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Reply Comments
Docket No. E-100, Sub 175

Dear Ms. Dunston:

Enclosed please find the Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for filing in the above-referenced docket.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, in Docket No. E-100, Sub 175, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 1st day of April, 2022.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	))))	REPLY COMMENTS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy"), pursuant to the North Carolina Utilities Commission's ("Commission" or "NCUC") August 13, 2021 *Order Establishing Biennial Proceeding Requiring Data, and Scheduling Public Hearing* (the "2021 Scheduling Order") and subsequent order granting extension of time, and hereby submit the Companies' Reply Comments in response to the initial comments filed by the Public Staff – North Carolina Utilities Commission ("Public Staff"), the Southern Alliance for Clean Energy ("SACE"), and, jointly, the North Carolina Sustainable Energy Association ("NCSEA") and the North Carolina Clean Energy Business Alliance ("NCCEBA" and together with NCSEA, "NCSEA/CCEBA" and together with SACE, the "Joint Solar Advocates").[1]

INTRODUCTION

The purpose of this biennial proceeding is to establish each utility's standard avoided cost rate tariffs and terms and conditions for service offered to qualifying facilities ("QFs") to comply with Section 210 of the Public Utility Regulatory Policies Act of 1978

[1] NCSEA/CCEBA expressly support SACE's Initial Comments. *See* CCEBA/NCSEA Initial Comments, at 3–4.

(“PURPA”)[2] and to review the methodology used to fix avoided cost rates to ensure continuing compliance with applicable Federal Energy Regulatory Commission (“FERC”) regulations,[3] as well as North Carolina’s PURPA implementation framework, N.C. Gen. Stat. § 62-156.[4] This proceeding follows the more streamlined 2020 avoided cost proceeding (“2020 Sub 167 Proceeding”), where the Commission’s August 13, 2021 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* (“2020 Sub 167 Order”) determined that DEC’s and DEP’s avoided cost rates and methodology were compliant with PURPA and appropriate for use in fixing rates to be offered to QFs. This proceeding also follows the Commission-directed stakeholder engagement effort to evaluate the Companies’ avoided cost methodologies and additional issues raised by the Commission’s April 15, 2020 *Order Establishing Standard Rates and Contract Terms For Qualifying Facilities*, issued in Docket No. E-100, Sub 158 (“2018 Sub 158 Order”).

As detailed in the Companies’ Joint Initial Statement, Duke Energy devoted significant time, effort and resources in 2021 to work with Public Staff and to engage other interested parties including the Joint Solar Advocates to develop consensus on reasonable, standardized, and repeatable methodologies in an effort to resolve avoided cost issues that are typically contentious, such as the appropriate fuel forecasting methodology, avoided CT costs and cost adjustments, avoidable hedging costs, line losses and an appropriate performance adjustment factor (“PAF”) methodology.

After reviewing the Companies’ Avoided Cost Submissions, the Public Staff advocates for the Commission to approve the Companies avoided capacity and energy rates

[2] 16 U.S.C.A. § 824a-(3).
[3] 18 C.F.R. § 292.304.
[4] N.C. Gen. Stat. § 62-156(b).

subject to certain minor recommendations to be addressed in future proceedings, as discussed herein.

Full alignment was not achieved with the Joint Solar Advocates. However, the number of contested issues presented in this proceeding is substantially narrowed from past proceedings, and SACE expresses its appreciation for the Companies' efforts and productive discussions towards achieving consensus.[5] Specific to calculating the Companies' forecasted future avoided capacity and avoided energy costs, the Joint Solar Advocates present four substantive issues for Commission decision: (1) replacing the avoided CT unit used in calculating avoided capacity rates under the peaker methodology with a significantly higher cost aeroderivative turbine; (2) revising the natural gas price forecasting methodology used in calculating avoided energy rates to significantly limit reliance on forward market pricing; (3) including an assumed avoided cost of carbon emissions in light of North Carolina's recent enactment of Session Law 2021-165 ("HB 951"); and (4) modifying the solar integration services charge ("SISC") methodology to address certain critiques presented by SACE's consultant, Mr. Brendan Kirby. For reasons further addressed in these reply comments, the Companies do not agree that these recommendations are reasonable adjustments to DEC's and DEP's avoided cost rate calculation methodology and ask that the Commission reject the Joint Solar Advocates arguments to significantly increase the Companies' avoided capacity and energy cost rates in excess of just and reasonable levels authorized by the well-established PURPA implementation framework in North Carolina.

[5] SACE Initial Comments, at 2.

While the Companies do not support the Joint Solar Advocates' targeted proposals to unjustly increase administratively-determined avoided cost rates paid to QFs under the State's traditional PURPA implementation framework, the Companies do recognize that economic and regulatory circumstances and the State's resource planning framework for encouraging solar and other non-carbon emitting technologies is evolving rapidly in light of HB 951's carbon reduction goals and new energy policy directives to promote the continuing energy transition in the State. Duke Energy has already sought Commission authorization of a 2022 solar procurement of utility-owned and third-party QF controllable purchased power solar energy resources and anticipates that the Carbon Plan-informed volume of needed new solar resources will provide significant near-term market opportunities for solar QFs to deliver competitively procured clean energy to Duke Energy's customers at least cost. However, as recognized by the Public Staff, it would be premature to presume the impact of a future Commission-approved Carbon Plan in advance of such approval—or even in advance of its filing with the Commission.

The other significant issues raised in this proceeding relate to whether it is reasonable and appropriate at this time to evolve North Carolina's well-established PURPA implementation framework, either by considering other methodologies for calculating avoided costs or, as extensively argued by the Joint Solar Advocates, looking for new opportunities to compensate solar QFs for providing ancillary services. As to the former, Duke Energy believes that the peaker methodology continues to provide a reasonable administratively-calculated proxy for establishing DEC's and DEP's future avoided capacity and avoided energy costs at this time. However, the Companies also recognize—and discussed with stakeholders in advance of this proceeding—that the FERC through

Order No. 872 has recently identified new more market-oriented and PURPA-compliant competitive price frameworks to quantify future avoided costs that mitigate overpayment risk for customers and that such methodologies could be evaluated in the future to set avoided costs. Such approaches could be considered if the Commission believes continued use of the peaker methodology is no longer appropriate. Turning to the Joint Solar Advocates generalized arguments for reshaping the PURPA mandatory purchase framework to facilitate first-of-its-kind compensation to QFs for ancillary services, the Companies continue to believe that such proposals are inappropriate, unnecessary, and would increase costs for customers for the reasons discussed in the Companies' Joint Initial Statement. As highlighted in the Companies' Joint Initial Statement and corroborated by the Public Staff's investigation, there is **no precedent anywhere**—nor have the Joint Solar Advocates cited any—for a state regulatory authority utilizing the PURPA avoided cost framework to provide incremental compensation to QFs for providing ancillary services. Moreover, as addressed in the Companies' Joint Initial Statement and not controverted by the Joint Solar Advocates, no solar QFs to date have demonstrated the capability or offered to contractually obligate themselves to operate in a controlled manner that avoids the increased integration costs that the addition of PURPA solar actually creates on the system due to the intermittent nature of solar power being injected into the system. To the extent the Joint Solar Advocates seek to provide new market opportunities for new solar QFs to provide controllable solar energy resources to the Companies at least cost, HB 951 provides a significant opportunity through the Carbon Plan framework and Duke Energy has committed to work with stakeholders to evaluate an appropriate purchase power agreement framework in advance of next solar procurement under the future Carbon Plan.

Finally, the Companies have taken initial steps to implement Order No. 872 by updating their as-available energy rates and Notice of Commitment Forms. Public Staff supports both the updated as-available Marginal Cost Rates included in Schedule PP and updating the Notice of Commitment Form as appropriately implementing the new legally enforceable obligation requirements under 18 C.F.R. 292.304(d)(3). Specific to the Notice of Commitment Form, the Companies are proposing to modify the large QF form to resolve the limited concern raised by CCEBA/NCSEA.

REPLY COMMENTS

I. Avoided Capacity Rates

A. The Public Staff Supports Approval of the Companies' Avoided Capacity Rates

After review of the Companies' capital cost inputs, line losses, seasonal allocations, and other assumptions incorporated into DEC's and DEP's avoided costs, the Public Staff finds that the Companies' avoided capacity rates reflected in Schedule PP are reasonable[6] and recommends that the Commission approve them.

B. DEC's and DEP's First Years of Avoidable Capacity Need is Reasonable

The Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms For Qualifying Facilities*, issued in Docket No. E-100, Sub 158 ("2018 Sub 158 Order") directed the utilities to "include a specific statement [in the Companies' integrated resource plans ("IRP")] addressing the utility's future capacity needs to be used to determine the first year of avoidable capacity need in the next biennial avoided cost proceeding."[7] Following this directive, the Companies identified their next year of

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[6] Public Staff Initial Statement, at 37, 40, 59.
[7] *2018 Sub 158 Order*, at 10 (Findings of Fact 19, 22).

avoidable undesignated capacity need in their respective 2020 IRPs. Because the Commission subsequently waived the Companies' obligation to file updated 2021 IRPs under Rule R8-60(h)(2), DEC and DEP presented an update to their first years of undesignated capacity need in DEC/DEP Exhibit 8, which was filed with the Companies' Joint Initial Statement.[8] The Public Staff finds the Companies' first year of need analysis to be reasonable and no other intervenor submitted comments addressing the issue. Accordingly, the Companies' respectfully request that the Commission approve the Companies reliance upon a first year of avoidable undesignated capacity need of 2028 for DEC and 2024 for DEP in developing their respective avoided cost rates.

C. Avoided CT Unit Cost Assumptions

SACE proposes to significantly increase the Companies' avoided capacity cost by asking the Commission to reject the Companies' continued use of a F-frame CT in applying the peaker methodology and, instead, to require use of the significantly more expensive aeroderivative turbine unit.[9]

As explained in the Companies' Joint Initial Statement, DEC and DEP worked with the Public Staff and Dominion to develop the proposed methodology for calculating CT cost estimates, which is based on publicly available data from the Energy Information Administration ("EIA") for an F-frame CT. The Companies have used an F-Frame CT as the avoided unit in at least the last four avoided cost proceedings dating back to 2014. Because the utilities typically plan to build multiple CTs at a single site and the EIA data

[8] DEC's first year of undesignated capacity need is 2028. DEP's first year of undesignated capacity needs is 2024.

[9] *See* SACE Initial Comments, at 12–13, Table 1 (identifying that the overnight capital cost and fixed operations and maintenance costs of an aeroderivative turbine compared to a F-Frame CT is 65% and 133% higher, respectively).

is based on a single CT, the Companies and Dominion proposed a 7% adjustment to reflect economies of scale as reasonable. The Public Staff finds the Companies' continued use of the F-Frame CT as well as the greenfield economies of scale adjustment to be reasonable and also agrees with the Companies that a brownfield cost decrement is not appropriate for inclusion in calculation of avoided capacity rates at this time given the lack of certainty regarding the location of future CT builds.[10]

SACE opposes the Companies' continued use of a CT as the avoided peaking unit, asserting that "the combustion turbine ("CT") that Duke has chosen to use as its projected avoided peaking resource is inconsistent with economical future procurement as well as Duke's suggested future procurement."[11] SACE posits in a HB 951 carbon-constrained world that an aeroderivative gas turbine is more appropriate as a peaking unit in the near term, while a hydrogen-capable turbine and/or battery storage will be more appropriate as a peaking unit in the "near future."[12] To the contrary, however, the Companies' continued use of CTs as a peaking resource remains accurate and appropriate under the peaker methodology to determine the avoided cost of capacity.

1. <u>An Aeroderivative Gas Turbine Is Not More Appropriate Than A CT As a Peaking Avoided Capacity Resource</u>

SACE asserts that "[a]n aeroderivative turbine will be the most economical highly flexible CT technology at present, making it a more appropriate resource to use to calculate avoided capacity costs in this proceeding than a simple-cycle CT that cannot offer the same flexibility and operational efficiencies."[13] As a threshold matter, it is not clear from

[10] Public Staff Initial Statement, at 14–15.
[11] SACE Initial Comments, at 4.
[12] *Id.* at 3.
[13] *Id.* at 8.

SACE's Initial Comments whether it is recommending that the Commission require the Companies to calculate their avoided costs using an aeroderivative gas turbine as the peaking unit *in this proceeding* or in another proceeding to take place in the "near term." In either case, however, the Companies note that although an aeroderivative turbine may provide greater flexibility attributes than an F-frame CT, an F-frame CT provides fast start and ramping capabilities at an installed cost approximately 60% below the cost of an aeroderivative CT.

In addition, according to SACE, "[t]he peaker method is a hypothetical exercise that measures the capacity value of a QF based on the assumption that the capacity provided by the QF allows the utility to avoid building a least-cost peaking unit that it otherwise would have built."[14] This claim mischaracterizes the peaker methodology. The peaker methodology assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost.[15] Under the theoretical corollary of the peaker methodology, even if a utility's next planned unit is not a simple cycle peaker, the peaker methodology still accurately

[14] *Id.*
[15] *Order Setting Avoided Cost Input Parameters*, Docket No. E-100, Sub 140, at 9 (Finding of Fact 23), 30 (Dec. 31, 2014) (finding that "a CT is an appropriate proxy for the capacity-related portion of the total costs of a generating unit that might be added to the system in order to increase system capacity. Thus, avoided capacity costs should equal the cost of a hypothetical CT and, together with the marginal system running costs, these will equal the cost of any generating plant, including a baseload plant.").

represents a valid estimate of the utility's avoided costs. From an installed cost perspective, a simple cycle F-frame peaking unit is typically the least expensive type of traditional resource that the Companies can construct to provide capacity for reliability purposes. Building incremental peakers for capacity and relying on the remaining system for marginal energy is always an option within the resource planning process.

SACE also concedes that "Duke does not designate aeroderivative technology as part of its preferred plan in its most recent IRP" but then suggests that this is "not dispositive" because SACE does not believe Duke "evaluated the relative merits of CT versus aeroderivative technology options"[16] The Companies' respective 2020 IRPs and Supplemental Portfolio B filed in Docket No. E-100, Sub 165 demonstrate the need for F-frame CTs and do not show any need for aeroderivative CTs.

As the Companies acknowledged in their Reply Comments in the E-100, Sub 167 Avoided Costs proceeding (which also relied upon the 2020 IRP), H-class or other more advanced aeroderivative CTs could be a future way for the Companies to manage the intermittent output of must-take solar generators. These units provide greater flexibility and operational capability to integrate variable and intermittent renewable energy production, which—as SACE points out—comes at a "markedly higher" cost.[17] In that event, however, the cost causer for the more expensive CT unit would be the solar providers themselves and, thus, the incremental cost of constructing H-class or aeroderivative CTs versus F-class CTs should not also be paid for by customers to the solar providers as avoided costs.[18]

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[16] *See* SACE Initial Comments, at 12.
[17] *Id.*
[18] *Id.* at 11. SACE pointed to this acknowledgment in its Initial Comments but failed to reference the Companies' statement regarding cost causation and allocation. *Id.*

In sum, the technology type used as the basis for the Companies' CT capital cost is consistent with past and present IRPs and avoided cost filings, appropriate under the peaker methodology, most reflective of current system conditions at this time, as well as supported by the Public Staff. Thus, the avoided capacity cost based on an F-frame CT continues to be the appropriate avoided capacity unit to be used as the basis for the avoided capacity cost filed in Docket No. E-100, Sub 175.

2. Hydrogen-Capable Turbine and/or Battery Storage Are Not More Appropriate Than CT As A Peaking Avoided Capacity Resource Under HB 951

While SACE "does not recommend" using the cost of hydrogen powered turbines or batteries to calculate avoided capacity costs in this proceeding, it argues that doing so might be appropriate in a future proceeding.[19] The Companies view hydrogen-capable turbines as an important potential enabler to achieve the carbon reductions mandated by HB 951. Because hydrogen fuel is a developing technology that has several potential pathways to deployment, it will likely play only a minor role in meeting the 2030 Carbon Plan goals. In addition, significant investments will be required into research and development and pilots by 2030 to make hydrogen a viable option on the path to full decarbonization by 2050. The Companies believe that the avoided capacity cost developed using publicly available EIA data for an F-frame CT, and supported by the Public Staff, is appropriate for use in the E-100, Sub 175 docket.

3. Future Resources Under HB 951

Under HB 951, the Companies will need to procure large quantities of renewable resources to meet specified carbon reduction targets. The Companies will also need to

[19] *Id.* at 16.

acquire very low- or zero-emitting technologies that can be dispatched to meet energy demand over long durations to ensure adequate reliability given the variable output of solar and wind resources and to reach net-zero carbon emissions by 2050. The Companies are currently developing Carbon Plan portfolios to meet the carbon reduction targets mandated by HB 951; however, the resource portfolios are still under development and have not been completed at this time. While the Carbon Plan will necessarily require high levels of renewable resources, it is unknown at this time what thermal resources will be needed to produce a least cost plan that satisfies HB 951 resource planning and carbon emission reduction targets and provides an adequate level of reliability. Because of the current uncertainty regarding the resource mix that will result from the Carbon Plan and the likelihood that CTs will remain a critical part of the resource portfolio in the near term, at least, the Companies believe, and the Public Staff supports, that CTs are the appropriate peaking unit for use in this proceeding.

Further information and detail regarding resources to be included in the Companies' Carbon Plan will be known once the Commission selects a plan by the end of 2022.

D. Performance Adjustment Factor ("PAF") Capacity Multiplier

The Companies' proposed PAF adjustment is supported by the Public Staff and not controverted by any other intervenor.[20] As explained in their Joint Initial Statement, the Companies calculate the PAF using the weighted Equivalent Unplanned Outage Factor ("WEUOF") metric. The WEUOF metric is calculated using data from the Generating Availability Data System ("GADS") database maintained by the North American Electric Reliability Corporation ("NERC"). Because solar generation is not part of the mandatory

[20] Public Staff Initial Statement, at 15.

GADS reporting at this time, the system WEUOF calculation is based on the performance of the respective DEC and DEP generation fleets excluding Company-owned solar facilities.

Based on the 2021 NERC GADS Section 1600 Data Request and public comment, , mandatory GADS reporting for solar facilities of 50 MW or more is currently scheduled to begin in 2023 and mandatory reporting for solar facilities with total installed capacity of 20 MW or more is current scheduled to begin in 2024.[21] However, NERC plans to issue a revised Data Request and second public comment period this summer.[22] Thus, the Solar Generating Reporting instructions are not yet finalized, and mandatory reporting dates may be delayed. With the expected growth in utility-owned solar and potential wind facilities, the Companies believe it is important and appropriate to include these facilities in determination of the PAF once the GADS data for these facilities becomes available. The Companies are agreeable to addressing the inclusion of solar and wind generator outage data in the PAF calculation in future avoided cost filings. Given the Public Staff's support and the lack of comment from any other intervenor, the Commission should approve the Companies' proposed PAF adjustment methodology.

II. Avoided Energy Rates

A. Public Staff Supports Approval of the Companies' Avoided Energy Rates

After reviewing the Companies' Prosym modeling, including MW capacities, heat rates, and other inputs that characterize Duke's generation units, the Public Staff found the

[21] North American Electric Reliability Corporation, *RE: Request for Public Comment on the Addition of Photovoltaic Generation and Other Changes to the Generating Availability Data Systems (GADS) Section 1600 Data Request*, at 9 (May 3, 2021), https://www.nerc.com/pa/RAPA/PA/Documents/GADS_Section_1600_Data_Request_20210615.pdf.
[22] North American Electric Reliability Corporation, Section 1600 Data Requests, https://www.nerc.com/pa/RAPA/PA/Pages/Section1600DataRequests.aspx

Companies' avoided energy rates, as reflected in Schedule PP, to be "reasonably consistent with the 2020 Proceeding and [ ] appropriate for this proceeding."[23] Based upon its review, the Public Staff recommends that the Commission approve the Companies' avoided energy rates at this time.[24] The Public Staff does raise a limited concern regarding future natural gas pricing due to potential over-reliance upon lower-priced shale gas, which is addressed in Section II.B.2 below.

B. Natural Gas Commodity Price Forecast Methodology

1. Use of Forward Market Pricing

As set forth in the Companies' Joint Initial Statement, in the instant proceeding, the Companies have proposed to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before transitioning to fundamental forecast data for the remainder of the planning period. This approach, which the Public Staff accepts, is consistent with the Commission's Orders in the three most recent avoided cost dockets in 2020, 2018, and 2016[25] as well as the Commission's November 19, 2021 Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning (the "*Sub 165 IRP Order*"), all of which direct the Companies to use no more than eight (8) years of forward natural gas market prices before transitioning to fundamental forecasts in the preparation of their Carbon Plan filing.

Despite this history of Commission approval, NCSEA/CCEBA and SACE criticize the Companies' continued use of the natural gas price forecasting methodology most

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[23] Public Staff Initial Statement, at 40.
[24] *Id.* at 59.
[25] *2016 Sub 148 Order*, at 109 (Ordering Paragraphs 5–6); *2018 Sub 158 Order*, at 136 (Ordering Paragraph 20), *2020 Sub 167 Order*, at 60 (Ordering Paragraph 12).

recently approved in the 2020 Sub 167 proceeding, reciting arguments raised and rejected in past avoided cost proceedings. With respect to timing, NCSEA/CCEBA recommend the Commission require the Companies to utilize 18 months of forward market prices before transitioning to a blended fundamentals forecast,[26] and SACE similarly recommends that the Commission require the Companies to use 18 months of forward market prices, 18 months of blended prices, followed by fundamental forecasts.[27] In support of their recommendations, both NCSEA/CCEBA and SACE essentially "recycle" arguments presented in prior avoided cost and IRP proceedings—which the Commission did not adopt—to recommend the Commission now require Duke to adjust its natural gas price forecasting methodology for purposes of this proceeding.

In addition, NCSEA/CCEBA take issue with the Companies' use of IHS pricing data to set the fundamentals forecast, arguing that it is a private forecast that does not allow for transparency. The Companies relied on IHS pricing for their fundamentals forecasts in both DEC's and DEP's respective 2020 IRPs as well as to prepare the Companies' Schedule PP in the 2020 E-100, Sub 167 avoided cost proceeding, and the Commission approved the Companies' filings in both cases. Nevertheless, NCSEA/CCEBA and SACE ask the Commission to depart from that precedent, with NCSEA/CCEBA recommending that the Commission require the Companies to use at least two reputable sources to determine the fundamentals forecast prices, and SACE recommending that the Companies average the IHS data with Energy Information Administration's ("EIA") prices.[28] Again,

[26] CCEBA/NCSEA Initial Comments, at 18–22.
[27] SACE Initial Comments, at 16–23.
[28] CCEBA/NCSEA Initial Comments, at 18–22; SACE Initial Comments, at 19–21.

these arguments are substantially similar to ones made in past avoided cost proceedings, which the Commission declined to adopt.

The Companies request that the Commission reject NCSEA/CCEBA's and SACE's recommendations and reiterate, as explained in their Joint Initial Statement, that their natural gas commodity price forecasting methodology is reasonable and appropriate for this proceeding and consistent with the Commission's recent Sub 148, Sub 158, and Sub 167 Orders on this issue.[29] As noted in the Joint Initial Statement, the Companies (as well as intervenors and Public Staff) may support a different position on natural gas commodity price forecasting methodologies in future proceedings[30] and have committed during the stakeholder engagement process underway to develop the Carbon Plan to (1) use five (5) years of forward market natural gas forecasts followed by three (3) years of blending, before transitioning to fundamental forecasts; and (2) utilize the average of fundamental forecasts developed by EIA, EVA, IHS, and Wood MacKenzie to calculate market fundamental pricing.

2. Reliance on DS Hub Gas

The Public Staff expressed general concern regarding the Companies' reliance upon forecasted lower cost natural gas pricing utilizing the Appalachian basin's lower cost Dominion South ("DS") hub.[31] The Public Staff explains that the basis for this concern is the current lack of operating gas pipeline infrastructure near the DS Point hub due to the recent cancellation of the Atlantic Coast Pipeline, as well as the loss of two permits for the

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[29] Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of DEC and DEP, at 25–26 (filed Nov. 1, 2022) ("DEC & DEP Joint Initial Statement").
[30] *Id.*
[31] While the Public Staff does not recommend any change in the Companies' reliance on eight years of forward natural gas market prices in this proceeding, it indicates that it will be filing comments in the IRP docket addressing the appropriate reliance on Dominion South hub gas for planning purposes in developing the Carbon Plan.

Mountain Valley Pipeline ("MVP") following a ruling by the United States Court of Appeals for the Fourth Circuit in January 2022 that will likely delay its completion for another year or more. In response to the Commission's directive in the *Sub 165 IRP Order*, the Companies filed a Supplemental 2020 IRP Limited DS Hub Gas portfolio on February 9, 2022, which addressed potential limitations in the Companies' access to DS Hub gas. Despite its concern and the uncertain regulatory future for the MVP pipeline, the Public Staff "does not recommend the use of the Limited DS Hug Gas portfolio as the basis for calculating avoided energy rates" at this time.[32] Instead, the Public Staff forecast its intent to file reply comments in the Sub 165 IRP docket addressing the appropriate reliance on DS Hub gas in developing the Companies' 2022 Carbon Plan. The Public Staff filed those comments on March 30, 2022, recommending the Companies limit their reliance on Appalachian Gas in modeling the Carbon Plan.[33] However, the Public Staff did not propose any recommended modifications to avoided costs in this proceeding.[34] The Companies agree that the extent of their reliance on DS Hub Gas is an issue that will be further considered as part of the 2022 Carbon Plan and updated as regulatory circumstances surrounding the MVP pipeline provide more clarity regarding its eventual viability.

C. Implied Carbon Emissions Costs Should Not be Included in Avoided Energy Rates At This Time

In their Initial Comments, both the Public Staff and SACE addressed HB 951's potential impact on the Companies' avoided energy costs—specifically, whether it is appropriate to require the Companies to recognize an avoidable carbon emissions price or, as contemplated by Public Staff, to use an IRP portfolio that includes carbon pricing in

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[32] Public Staff Initial Statement, at 41.
[33] *See* Supplemental Reply Comments of the Public Staff, Docket No. E-100, Sub 165, at 6–7.
[34] *Id*.

setting avoided energy rates in this proceeding. The Commission has previously determined—including most recently in the 2020 Sub 167 Order—that carbon emission-related cost would only be avoidable where such costs are "known and verifiable,"[35] and the FERC has held that only "real costs" that are actually avoidable by a utility and its customers when the utility purchases QF power are properly accounted for and included in a utility's avoided costs.[36]

For its part, the Public Staff correctly recognizes that "HB 951 imposes a limit on total CO_2 emissions (mass cap) and does not impose a direct price on CO_2 emissions" and concludes that any "implied cost of carbon resulting from HB 951 cannot be accurately determined until a Carbon Plan is approved."[37] The Public Staff also asserts that it "may not be appropriate to include a price on carbon associated with capital investments as an input into the production cost model" and, therefore, the Public Staff plans to "make a determination on any avoidable cost of carbon emissions after the Carbon Plan is filed."[38] In contrast, SACE argues that HB 951's enactment was "self-executing" and suggests that it is now possible to calculate a "known and verifiable" avoidable cost of carbon today.[39] Accordingly, SACE recommends that the Commission order the Companies to recalculate their avoided costs using the Companies' 2020 IRP base case with carbon policy with an $5/ton carbon price, escalating annually, as a reasonable proxy for a future avoidable cost

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[35] *2020 Sub 167 Order*, at 7, 33 (recognizing that "ratepayers should not bear speculative or uncertain costs that are not avoided through purchase of power from a QF through the avoided cost rates that they ultimately pay"); *see also Order Setting Avoided Cost Input Parameters,* Docket No. E-100, Sub 140, at 8 (Finding of Fact 14), 42–44 (Dec. 31, 2014) (the *"Phase I Sub 140 Order"*).
[36] *See e.g., Cal. Pub. Utility Comm'n*., 132 FERC ¶ 61, 047, 61,267-68 (July 15, 2010), *clarification granted & rehearing denied*, 133 FERC ¶ 61, 059 (October 21, 2010), *rehearing denied*, 134 FERC ¶ 61,044 (Jan. 20, 2011) (clarifying that if environmental costs "are real costs that would be incurred by utilities," then they "may be accounted for in a determination of avoided cost rates.").
[37] Public Staff Initial Statement, at 8–9.
[38] *Id.* at 9.
[39] SACE Initial Comments, at 35.

of carbon under the Carbon Plan, or in the alternative the Regional Greenhouse Gas Initiative ("RGGI") allowance price, as a proxy for the cost of carbon under HB 951.[40] Because HB 951 does not legislate a direct price or tax on carbon emissions that can be avoided by purchase from QFs[41], the Companies agree with the Public Staff that the cost of implementing the carbon reductions mandated by HB 951 are not yet known and verifiable.

This approach is consistent with the Commission's findings in the *2020 Sub 167 Order* and earlier *Phase I Sub 140 Order* that avoided costs should be calculated using only "known and verifiable" costs, and that "speculative costs" that are not "sufficiently certain" to be avoided by customers should not be included in avoided costs.[42] In the Sub 140 proceeding, the Commission considered arguments from intervenors that proposed federal carbon regulations, which would have imposed costs on utilities within the timeframe of QF contracts set in the proceeding, should be factored into the Companies' avoided cost calculations. In rejecting intervenors' proposal, the Commission found that attempting to assess the cost of the proposed regulations would be "speculative at best," rendering it "inappropriate for ratepayers to shoulder such costs until they become known and verifiable."[43]

Here, there is no certainty regarding the resources to be developed or any future implied cost of carbon to be included in the approved Carbon Plan and, therefore, no real

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[40] *Id.* at 36–37.
[41] This is in contrast to Regional Greenhouse Gas Initiative ("RGGI") costs that the Commission recently approved as appropriately avoidable in forecasting Dominion Energy North Carolina's avoided energy cost rates in the 2020 Sub 167 proceeding. *See 2020 Sub 167 Order*, at 7, 33.
[42] *Phase I Sub 140 Order*, at 8 (Finding of Fact 14), 14 ("The costs of carbon emissions control are not sufficiently certain to be included in avoided costs at this time. If in the future carbon costs become known and verifiable, it may be appropriate for those costs to be included at that time.").
[43] *Id.* at 14.

or known and verifiable costs associated with future carbon emission reductions under the Carbon Plan that should be avoidable at this time. Accordingly, any implied cost of carbon cannot be accurately determined until the Commission approves a Carbon Plan.

SACE recommendation that the assumptions used in the Companies' 2020 IRP Portfolio B as a benchmark for potential future carbon reduction were just that—assumptions; they are *not* known and verifiable costs that are avoidable by customers today. To support the adoption of this clearly "speculative" approach, SACE makes an attenuated argument that HB 951 empowers the Commission to "take all reasonable steps" to achieve the carbon reduction mandates of the Session Law.[44] But SACE fails to explain how incorporation of a hypothetical backward looking carbon cost adder that is not based on any known or measurable carbon price or tax into the costs paid by ratepayers to QFs contracting under the Schedule PP is reasonable—let alone needed—to achieve HB 951's carbon reduction goals. To the contrary, HB 951 sets out a clear process that is already well under way to expeditiously develop and approve a Carbon Plan that will set the Companies on a path to achieve the State's carbon emission reduction goals.

In sum, the Companies agree with the Public Staff's recommendation that once a Carbon Plan is approved and the avoidable cost of carbon, if any, is determined within those proceedings, that the Commission could direct the Companies to use the approved Carbon Plan as the expansion portfolio in its next avoided cost filing. That expansion portfolio would implicitly include the Commission-approved avoidable cost of carbon in its calculation of avoided energy and capacity rates, if appropriate. The Companies are amenable to the Public Staff's proposal and agree that the future base portfolio selected

[44] SACE Initial Comments, at 35–36.

from the Carbon Plan should be used to calculate avoided cost rates in the next biennial avoided cost proceeding. Because the Commission will formally approve the Carbon Plan, the modeled cost of the resources identified to meet HB 951's carbon reduction goals will then be known and verifiable.

In conjunction with potentially accepting an avoided cost of carbon as a known and verifiable cost in a future avoided cost proceeding, the Companies recommend that the Commission consider whether renewable energy credits and environmental attributes should be credited to customers if customers are paying QFs for avoided carbon benefits of generation. HB 951 ensures that all environmental attributes associated with new generation selected by the Commission in the Carbon Plan are conveyed to the utility for the benefit of its customers while the traditional standard PURPA contract does not convey such attributes.[45] The Public Staff similarly identifies the "question of environmental attributes" as one to be considered in the future.[46] The Companies agree that this issue should be evaluated if avoidable cost of carbon emissions reductions are to be included in any fashion as part of future avoided energy costs for QF purchases as the utility and customers will obtain all environmental and renewable attributes from both utility-owned and third-party solar resources procured under the Carbon Plan.[47]

D. No Action is Needed or Appropriate to Compensate QFs for Ancillary Services in this Proceeding

Section III.5 of the Companies' Joint Initial Statement addressed Duke Energy's investigation of whether the Companies' avoided cost rates and terms for purchasing QF power should be modified to provide a framework under which a QF could demonstrate its

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[45] Session Law 2021-165. Part I, §. 2.b.
[46] Public Staff Initial Statement, at 10.
[47] Session Law 2021-165, Part I, § 1 (2).b.

ability, and contractually obligate itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources and then be compensated for those benefits.[48] After a thorough investigation of the PURPA "must take" framework for purchasing QF power as well as both the operational capabilities of QFs to provide ancillary services to DEC and DEP as well as the Companies' limited need and current capability to provide ancillary services from fleet resources, the Companies determined that no changes to DEC's or DEP's avoided cost rates or terms were necessary or appropriate in this proceeding relating to provision of positive incremental ancillary services by QFs.[49]

The Public Staff similarly concludes that "it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke's SISC by smoothing their volatility."[50] However, the Joint Solar Advocates argue extensively that QFs are being undercompensated under the current PURPA avoided cost framework for delivering some ancillary services today and that solar QFs could provide a larger suite of ancillary services in the future. The Joint Solar Advocates argue for a "pilot program to test the effectiveness of an ancillary services market in North Carolina"[51] while Public Staff "solicits feedback from Duke, DENC, and other intervenors on the potential benefits of initiating a proceeding to investigate this matter and potentially establish a pilot program to procure a small amount of ancillary services from [inverter-

[48] DEC & DEP Joint Initial Statement, at 34–37.
[49] *Id.* at 37. Dominion Energy North Carolina did not directly address this issue, but did note that QF behind the meter resources "do not have the capability to effectively follow direct signals from PJM or relayed instructions by the Company" and therefore are "not eligible to participate in ancillary service markets for the benefit of system customers" in PJM. *See* Initial Statement and Exhibits of Dominion Energy North Carolina, at 13, n.19.
[50] Public Staff Initial Statement, at 19.
[51] CCEBA/NCSEA Initial Comments, at 17.

based resources], either through the establishment of a limited competitive solicitation from QFs, or a pilot program at one of Duke's or DENC's utility-owned solar sites."[52]

For reasons generally stated in the Companies' Joint Initial Statement and further addressed below, the Companies do not agree with the Joint Solar Advocates' argument that incremental compensation to QFs for current or future ancillary services is appropriate under PURPA's must-take power purchase framework. Further, Duke Energy's fleet resources provide all needed additional ancillary services today and there is no incremental need to establish complex new contract structures that would deviate from the mandatory purchase framework to facilitate a limited opportunity for Commission-regulated QFs to begin providing FERC-regulated ancillary services to support reliable system operations. Finally, to the extent the Companies identify a need for ancillary services from solar generators in the future, new, larger solar resources to be procured under the Carbon Plan would be more capable of delivering these grid services at a lower cost to customers than restructuring grid operations to procure ancillary services from distributed QFs.

1. <u>Duke Energy's avoided cost rates fully compensate QFs for delivering energy and capacity, and no incremental compensation for ancillary services is appropriate under PURPA</u>

Ancillary services are necessary to the provision of reliable transmission service and are provided under the Companies' FERC-regulated Joint Open Access Transmission Tariff ("Joint OATT").[53] Section 210 of PURPA creates a limited exception to FERC's

[52] Public Staff Initial Statement, at 19.

[53] Joint OATT Section 3 Ancillary Services and Generator Services, Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service), Schedule 3 (Regulation and Frequency Response Service), Schedule 4 (Energy Imbalance Service), Schedule 5 (Operating Reserve – Spinning Reserve Service), Schedule 6 (Operating Reserve Supplemental Reserve Service) *accessible at https://www.oasis.oati.com/duk/; see generally* Order No. 888, FERC Stats. & Regs ¶ 31,036 (1996) (functionally unbundling transmission service and requiring that Transmission Providers establish open access transmission tariffs that include ancillary services determined to be needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service).

exclusive jurisdiction under the Federal Power Act over the rates, terms, and conditions of service for the transmission and sale at wholesale of electric energy in interstate commerce.[54]

Under PURPA and through FERC's implementing regulations, Congress established a framework to encourage wholesale market opportunities for cogenerators and small power producers by requiring the Companies to interconnect with QFs and to buy "any energy and capacity which is made available from a qualifying facility" at avoided cost rates regulated by the applicable State regulatory authority.[55] QFs are not required to obtain transmission service to sell their output to the interconnecting utility[56] and QFs' operations are exempt from much of the federal regulatory framework under the Federal Power Act.[57] QF sales of "energy or capacity . . . made pursuant to a state regulatory authority's implementation of section 210 [of PURPA] shall be exempt from scrutiny under sections 205 and 206."[58]

As noted in Duke Energy's Joint Initial Statement, FERC has recognized that rates for purchasing "'energy' from QFs under Section 210 of PURPA includes the entire output of the QF, including capacity, energy and ancillary services."[59] This statement—made in

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[54] 16 U.S.C. § 824(a)–(b). Outside of purchase arrangements between utilities and QFs, the rates and terms for ancillary services in the wholesale power market are exclusively FERC-jurisdictional. *See e.g., Cal. PUC*, 132 F.E.R.C. ¶ 61,047, 61337 (2010) (explaining that "[FERC's] authority under the FPA includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce by public utilities. While Congress has authorized a role for States in setting wholesale rates under PURPA, Congress has not authorized other opportunities for States to set rates for wholesale sales in interstate commerce by public utilities, or indicated that the [FERC's] actions or inactions can give States this authority").

[55] 18 C.F.R. § 292.303(a); *see also* 16 U.S.C. § 824a-3(a)(2) (articulating mandatory purchase obligation requirement).

[56] *PáTu Wind Farm, LLC v. Portland GE*, 151 FERC ¶ 61,223, 62452, n. 102, 2015 FERC LEXIS 87 (Jun 18, 2015).

[57] 16 U.S.C. § 824a-3(e)(1); 18 C.F.R. § 292.601(c).

[58] 18 C.F.R. § 292.601(c).

[59] *See Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, 123 FERC ¶ 61,055, n. 869, 2008 FERC LEXIS 788 (Apr. 21, 2008).

the context of clarifying the scope of QF exemptions from FERC oversight of market-based rates under sections 205 and 206 of the FPA—recognizes that utilities are required to purchase a QF's entire capacity and energy output, which may include some ancillary services related to that capacity and energy.[60] Outside of setting just and reasonable avoided cost rates for energy delivered by QFs under PURPA, however, the Commission's jurisdiction over ancillary services—FERC-regulated transmission services under the Joint OATT—is extremely limited.[61]

Turning to the question of whether the Companies' avoided cost rates are appropriately designed to compensate QFs for the full avoided cost of energy and capacity (including ancillary services, if any) delivered to the Companies, the answer is "yes" and, therefore, no incremental value for QFs' potential provision of positive ancillary services is appropriate. As recognized by SACE, it has been well-established since FERC's rulemaking Order No. 69 was issued nearly 40 years ago that utilities must purchase QFs' output of energy and capacity (if needed) at the utility's "full avoided cost" under PURPA.[62] PURPA is a "must purchase" construct where all "electric power generated by

[60] FERC has also recently disclaimed jurisdiction under Section 205 of the FPA to determine whether compensation for "reactive service" should be authorized where a QF's PPA selling capacity and energy exclusively to its interconnected utility was subject to state PURPA implementation. *See Cherokee Cty. Cogeneration Partners, LLC*, 176 FERC ¶ 61,069, at P. 16 (2021).

[61] *See* Order No. 888-B, 81 FERC ¶ 61,248 at P 43 (1997) (explaining that "[A]ncillary services is not a sale-for-resale of power. Rather, they are part of the costs of transmission which the QF must bear, in the absence of an agreement to share such costs with the transmitting utility"); *Sagebrush*, *a California Partnership*, 130 FERC ¶ 61,093, at P 37, n.65 (2010) (finding exemptions from FPA Section 205 and 206 not applicable where the services a QF is proposing to offer "involves the provision of transmission service, not sales of energy or capacity."). Notably, the Commission seemed to recognize that its authority was limited under PURPA to fixing avoided cost rates, finding that approving an "integration services charge proposed as a separate line item charge calls into question compliance with FERC's regulations requiring utilities to purchase energy and capacity from QFs." *2018 Sub 158 Order*, at 90.

[62] *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 404 (1983) (affirming 18 C.F.R. § 292.304(b)(2) requirement that a utility must purchase electricity from a qualifying facility at a rate equal to the utility's full avoided cost).

the Facility"[63] delivered and made available by the QF seller to the utility is purchased at DEC's or DEP's avoided costs. The Companies have long used the peaker methodology to forecast DEC's and DEP's full avoided costs, which the Commission has repeatedly found reasonable for fixing avoided cost rates.[64] The Commission has explained that "[p]roperly established, [avoided cost] rates must, as reasonably accurately as possible, approximate economic indifference between a utility's purchase of energy and capacity from a QF and supplying the equivalent energy and capacity from another source, including self-generation."[65] As the Companies' Joint Initial Statement explains, the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)."[66]

As designed and as applied by Duke Energy, the peaker methodology inherently provides the operational capacity value of the avoided CT unit, which would include any value of ancillary services the hypothetical avoided CT is capable of providing. While there is not a discrete adjustment or "adder" for operating the avoided CT unit to provide ancillary services, the theory behind avoiding the capital and operating cost of the peaker unit and marginal running costs of the system is that it fully represents the capacity and

[63] *See* DEC & DEP Joint Initial Statement, at DEC/DEP Exhibit 1, DEC/DEP Exhibit 3. Schedule PP provides that Seller and Company shall agree to the Contract Capacity of the QF facility committing to sell power to DEC or DEP, and the Companies standard Purchase Power Agreement By a Qualifying Cogenerator or Small Power Producer provides that the QF "shall sell and deliver exclusively to Company all of the electric power generated by the Facility."

[64] *See* DEC & DEP Joint Initial Statement, at 14, n.24 (detailing history of Commission acceptance of use of peaker methodology to calculate avoided costs).

[65] *2018 Sub 158 Order*, at 91.

[66] DEC & DEP Joint Initial Statement, at 13–14 (citing *Phase I Sub 140 Order*, at 30). Of note, the Commission has recognized that other methodologies also represent the full avoided cost without taking into account ancillary services costs. *See 2016 Sub 148 Order* at 86 (finding "persuasive the testimony of Dominion witnesses Petrie and Gaskill that LMPs reflect the underlying supply and demand, and associated local congestion and marginal losses, across the electric system.").

energy value that can be avoided by purchasing power from a QF. For that reason, Duke disagrees with the Joint Solar Advocates' arguments that current avoided costs do not appropriately and fully value the QF's capacity and energy, inclusive of any ancillary services that may be delivered by a QF.

The Joint Solar Advocates also argue that the Commission should look for future "benefits" to support incremental costs to be avoided by purchasing power from QFs as a corollary to the Commission's recent determination that solar integration costs reduce avoided energy costs.[67] This argument is also misplaced. The SISC adjustment to the Companies' avoided energy rates is designed to address "costs that the utility may incur, not otherwise accounted for as a result of purchases from a QF."[68] While a QF conceivably could enter into an alternative form of more controllable contract committing to provide ancillary services (and forego avoided capacity and avoided energy revenue), the QF may not lawfully be paid at rates above the utility's full avoided capacity and energy costs. The Commission would have to determine that the utility will actually avoid additional avoided capacity and energy costs as a result of the QF providing ancillary services. As Duke Energy's Joint Initial Statement explains, there is not an incremental need for ancillary services on the Companies' systems as the Companies' existing generating fleets are capable of providing all needed ancillary services.[69] Public Staff does not challenge this point while SACE wrongly suggests that it is "irrelevant" whether there is a need for additional ancillary services and a cost to be avoided.[70] However, both the FERC[71] and

[67] CCEBA/NCSEA Initial Comments, at 12; SACE Initial Comments, at 27.
[68] *2018 Sub 158 Order*, at 92.
[69] DEC & DEP Joint Initial Statement, at 37.
[70] CCEBA/NCSEA Initial Comments, at 7; SACE Initial Comments, at 31.
[71] Order No. 872, 173 FERC ¶ 61,158 at PP 157, 196 (2020) (citing *City of Ketchikan*, 94 FERC ¶ 61,293 at P 62,061 (2001) ("when capacity is not needed, the avoided capacity cost rate can be zero.").

this Commission[72] have recognized that utilities should not compensate QFs for avoidable capacity when there is no need for capacity to be avoided. Paying a QF incremental compensation for ancillary services where the utility is not actually avoiding a capacity or energy cost is unjust and unreasonable and inconsistent with PURPA.

Finally, there seem to be two operational "elephant(s) in the room" that further call into question the Joint Solar Advocates' unsupported arguments for solar QFs providing ancillary services. First, QFs selling under existing must-take purchase contracts have not been expected to (nor are they in any way contractually required to) limit the energy sold to DEC or DEP in order to provide any form of ancillary services, such as regulating reserves, contingency reserves, or balancing reserves—each of which would require increased utility coordination and utility control of the QFs' output to ramp up or ramp down the generating facility's energy output in real time. Imposing such a requirement would surely be challenged as infringing on QFs' rights to sell all energy made available under PURPA subject to limited system emergency curtailments, as noted by NCSEA/CCEBA.[73] Second, the Joint Solar Advocates each seem to assume that a QF would continue to be fully compensated for energy and capacity if it is also contracting to provide ancillary services.[74] However, as noted in Duke Energy's Joint Initial Statement[75] and recognized by Public Staff,[76] providing ancillary services would require both utility

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[72] *2018 Sub 158 Order*, at 48–49 (finding that "PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need").
[73] *See 2016 Sub 148 Order*, at 81 (describing utilities' limited rights to curtail QFs in system emergencies under Section 292.307 of FERC's PURPA regulations); NCSEA/CCEBA Comments at 9, n.7.
[74] SACE Initial Comments, at 30 (suggesting without explaining that it is "not necessarily true" that "a QF would need to produce less than its maximum energy and capacity in order to be able to provide ancillary services."); CCEBA/NCSEA Initial Comments, at 10 (explaining that "existing QFs [would expect to] continue to receive the same or greater level of compensation as under their existing contracts" in order to provide ancillary services in the future).
[75] DEC & DEP Joint Initial Statement, at 36.
[76] Public Staff Initial Statement, at 18.

control of the QF's generating facility and would inherently require the QF to produce less than its maximum energy and capacity. As the Public Staff explains, the QF would be "trading revenue from energy and capacity for revenue from ancillary services."[77]

Based upon the full avoided cost rates for capacity and energy calculated under the well-established peaker methodology and the fact that the Companies do not have a need for incremental resources to provide ancillary services, there is no legal basis under PURPA for the Commission to either increase the Companies avoided capacity and energy costs today or, prospectively, to develop a scheme to compensate QFs for ancillary services, as requested by the Joint Solar Advocates.

2. <u>Joint Solar Advocates do not identify any precedent for procuring ancillary services under a State's implementation of PURPA</u>

The Public Staff explains that its investigation did not identify any other regulated utility in the country, operating outside of an RTO, that procures ancillary services from a third party power supplier.[78] Duke Energy's investigation similarly did not identify any utility that uses small power producer QFs to provide ancillary services under PURPA nor any state Commission implementing PURPA that has asserted any incremental compensation is owed to QFs for providing positive ancillary services over and above the full avoided capacity and avoided energy value paid to QFs.[79] Notably, the Joint Solar Advocates also do not point to any precedent where another utility or State Commission has established rates for the provision of ancillary services or otherwise taken ancillary services into account in establishing avoided cost rates under PURPA. Recognizing that ancillary services are FERC-jurisdictional transmission services regulated under each

[77] *Id.*
[78] *Id.* at 17.
[79] DEC & DEP Joint Initial Statement, at 37.

Transmission Provider's OATT, it is unsurprising that other States have not pursued (and it is questionable whether State regulatory authorities would have jurisdiction under PURPA to establish) a compensation scheme or "pilot ancillary services market" as recommended by NCSEA/CCEBA.

3. <u>NCSEA/CCEBA's argument that solar QFs are providing grid services today without compensation is incorrect</u>

NCSEA/CCEBA assert that "QFs already provide certain ancillary services to Duke without compensation, which is unjust and unreasonable."[80] Specifically, they assert that "QFs are capable of providing voltage support" and point to QF Interconnection Customers' obligation to "maintain a constant voltage level" as evidence that solar QFs are providing reactive power under Section 1.8 of the state jurisdictional Interconnection Agreement ("IA").[81] NCSEA/CCEBA go on to suggest that "QFs are providing a grid service" and that compensation is due to QFs under the IA if Duke pays its own or affiliated generators for reactive power within the specified range (i.e., 0.95 leading to 0.95 lagging).[82]

While this is a novel argument in a PURPA proceeding in North Carolina, the FERC considered and rejected generally the same argument in establishing the *pro forma* Large Generator Interconnection Procedures and Large Generator Interconnection Agreement in Order No. 2003.[83] FERC explained its determination in a subsequent case that "[w]here a transmission provider does not separately compensate its own or affiliated generators for reactive power service within the deadband, it need not separately

[80] CCEBA/NCSEA Initial Comments, at 7.
[81] *Id.*
[82] *Id*. at 8.
[83] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546 (2003).

compensate non-affiliated (IPP) generators for reactive power service within the deadband."[84] This is because "an interconnecting generator should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation. Providing reactive power within the deadband is an obligation of a generator, and is as much an obligation of a generator as, for example, operating in accordance with Good Utility Practice."[85] Importantly, contrary to NCSEA/CCEBA's supposition, Duke Energy does not compensate its own fleet generators or affiliated generators for reactive power service.[86] Therefore, NCSEA/CCEBA's suggestion that they are providing grid services is incorrect and no compensation for reactive power is appropriate under the IA for solar QFs operating in parallel with the Duke Energy systems.

4. <u>A new proceeding to further evaluate procuring ancillary services from QFs is unwarranted and no further Commission action on this Sub 158 additional issue is needed at this time</u>

NCSEA/CCEBA discuss extensively how "solar + storage facilities are capable of providing additional ancillary services and providing grid operators new tools to balance and manage the grid."[87] NCSEA/CCEBA specifically point to a number of recent demonstration studies and technical reports analyzing contract structures and innovative approaches to controlling solar resources that could enable more flexible operations, reduce

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[84] *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 30 (2007).
[85] *Id.* at P 29.
[86] *See Cherokee Cty. Cogeneration Partners, LLC*, 175 FERC ¶ 61,002 at P 10 (representing to FERC that "DEC does not pay its own or affiliated generators for Reactive Service"). While the foregoing representation was specific to DEC, DEP also does not pay its own or affiliated generators for reactive service. Moreover, NCSEA/CCEBA's Exhibit 1 (Duke Energy's February 22, 2022 Comments in Docket No. RM22-2-000) are inapposite as they address situations where compensation for reactive power is appropriate under FERC's policies (e.g., where the Transmission Provider is compensating its own similarly situated generators for reactive power).
[87] CCEBA/NCSEA Initial Comments, at 12–13.

the need for curtailment of solar energy and potentially provide an array of essential reliability services to the grid.[88] Recognizing the lack of an existing market for ancillary services in North Carolina, these parties suggest that a stakeholder process is needed to address contractual, commercial, legal, and technical challenges in order to allow these significant benefits to be realized.[89] SACE similarly advocates that the Commission require Duke Energy to undertake a "stakeholder-informed study of the potential for QFs to provide ancillary services and the appropriate compensation, or by establishing a pilot program for ancillary services[.]"[90] Public Staff requests feedback on "potentially establish[ing] a pilot program to procure a small amount of ancillary services from [Inverter Based Resources], either through the establishment of a limited competitive solicitation from QFs, or a pilot program at one of Duke's or DENC's utility-owned solar sites."[91]

While the Companies appreciate the robust interest in a stakeholder process or pilot program, the Companies do not support such proposals at this time. The Companies' Joint Initial Statement identified that transitioning the Companies' modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would create costs rather than avoid costs and would require a fundamental change in how the grid is operated, along with major technical and financial investments.[92] Moreover, the only way to provide regulation up capability would be to curtail solar across the day and then release some of that curtailment to provide upward regulation when needed. This would require solar QF resources to forego a significant value in energy payments to do

[88] *Id.* at 13–16.
[89] *Id.* at 17.
[90] SACE Initial Comments, at 31.
[91] Public Staff Initial Statement, at 19.
[92] DEC & DEP Joint Initial Statement, at 36.

so. In contrast to some of the studies highlighted by NCSEA/CCEBA, high hourly variability of solar QFs on many cloudy days would make this type of operations even more challenging in North Carolina. Finally, this constant curtailment and then release for regulation up would require fundamental changes to the dispatch process and extensive re-engineering to incorporate it into the automatic generation control algorithm to distribute the signal across hundreds of (unpredictable, unreliable) resources instead of dozens of (predictable, reliable) resources. To date, no QFs have opted to mitigate their output to avoid the Solar Integration Service Charge, indicating that the ancillaries quantified to date in the SISC are not high enough value to forego the energy value.[93]

The Companies appreciate that utility-owned and, potentially, third-party controllable solar resources may be able to provide such capabilities in the future. To the extent the Companies identify a need for ancillary services from solar generators in the future, new, larger solar resources to be procured under the Carbon Plan—especially solar+storage resources as identified by NCSEA/CCEBA[94]—would be more capable of delivering these grid services at a lower cost to customers than restructuring grid operations to procure ancillary services from distributed QFs today. Accordingly, the Companies do not support a new proceeding to evaluate these issues and believe that no further Commission action on this Sub 158 additional issue is needed at this time.

E. The Companies' Proposed As-Available Marginal Cost Rates Adhere to PURPA and Should be Approved

[93] *Id.* at 36–37.

[94] DEP is currently testing the technical and operational capabilities of battery energy storage systems, including testing the Hot Springs Microgrid pilot project to provide various ancillary services. *Order Granting Certificate of Public Convenience and Necessity with Conditions*, Docket. No. E-2, Sub 1182 (May 19, 2019) (directing study to estimate the ancillary service benefits battery storage can provide DEP's system). This study is ongoing and the initial findings are anticipated to be filed with the Commission in late Summer 2023.

The Public Staff supports the Companies' Marginal Cost Rates proposal as a reasonable "as-available" energy rate option under PURPA for QFs that decline to commit to sell and deliver power to the Companies pursuant to a legally enforceable obligation for a specified future term.[95] In particular, the Public Staff noted that the proposed rate schedule will "ensure that QFs are paid actual marginal costs, rather than market forecasts" and "reduce overpayment risk."[96] SACE, however, expresses concern with the "ex-post" calculation methodology of new Marginal Cost Rates, suggesting that this approach is "not appropriate."[97]

SACE's comments focus on the changes Order No. 872 implemented to the LEO option under 18 CFR § 292.304(d)(1)(ii) that recognized the benefits of more accurate avoided energy rates over the term of the QF contract. However, the Companies' Marginal Cost Rates are intended to meet the "as available" requirements under 18 CFR § 292.304(d)(1)(i) for QFs that elect not to contract to sell their capacity and energy over a specified term. SACE also suggests that the ex-post calculation methodology will create "revenue uncertainty" for QFs and "result in more difficult QF financing" which would "weaken the PURPA market" in North Carolina.[98] These comments, too, miss the point that the Companies' Marginal Cost Rates are "as available" rates where the QF is not contracting to sell its capacity and energy to DEC or DEP for any specified future term. If a QF desires a short-term rate but seeks a fixed price and commits to deliver capacity and energy over a future term, the Companies offer other PURPA-guaranteed rate options for

[95] Public Staff Initial Statement, at 13–14; *see also* 18 C.F.R. 292.304(d)(1) (providing QFs the option to either sell energy "as available" or pursuant to a legally enforceable obligation to be delivered over a specified future term).
[96] *Id.*
[97] SACE Initial Comments, at 31–32.
[98] *Id.* at 32.

fixed price power sales of various terms, including the short-term 2-year Variable Rates contract option approved by the Commission in the *2020 Sub 167 Order*.

Finally, SACE is also incorrect that the Companies' proposed methodology to calculate the Marginal Cost Rates is not utilized in the industry today. As recognized by the Public Staff,[99] DEC and DEP use this same methodology to calculate transmission and wholesale imbalance billing rates. In addition, Duke Energy Florida uses a similar ex-post methodology to calculate as-available avoided energy cost rates.[100] Accordingly, SACE's concerns are not well-founded and the Marginal Cost Rate should be adopted and offered to QFs that elect only to sell as-available energy versus contracting to sell power to DEC or DEP for a specified future term.

III. Duke Supports Continued Use of Peaker Methodology Subject to Further Engagement with Public Staff, Joint Solar Advocates and other Stakeholders in the Future

In this proceeding, the Public Staff supports the continued use of the peaker methodology for both the Companies and DENC.[101] While the Joint Solar Advocates do not expressly object to the Companies use of the peaker methodology in this proceeding, both SACE and NCSEA/CCEBA argue that the Commission and interested stakeholders should begin to reconsider the appropriateness of the peaker methodology in light of HB 951 and the ongoing energy transition in the State.[102] The Public Staff likewise notes that there may come a time when the peaker methodology is no longer appropriate for use in

[99] SACE Initial Comments, at 13 n.18.
[100] DEC & DEP Joint Initial Statement, at 40 n.93.
[101] Public Staff Initial Comments, at 24.
[102] *See* NCSEA/CCEBA Initial Comments, at 17–18; SACE Initial Comments, at 3.

North Carolina in the future as utilities seek decarbonization and more generation comes from renewable resources with high capital and low variable costs.[103]

Because the peaker methodology remains a reasonable and well-accepted methodology by which to calculate avoided energy and capacity costs and no party has directly challenged its use in this proceeding, the Companies request that the Commission approve its continued use. Given the ongoing development of the Carbon Plan, the Companies commit to continue evaluating appropriateness of the peaker methodology in the future and will address this topic in their next biennial avoided cost proceeding in 2024. To the extent the Commission believes the Companies should consider shifting away from the peaker methodology in the future, FERC Order No. 872 approved a number of new approaches that rely upon competitive pricing methodologies by which a utility may compensate QFs for their output in lieu of traditional administratively-forecasted avoided costs methodologies.[104] As the Companies identified in their Joint Initial Statement, Order No. 872 implementation was a topic of discussion with stakeholders in advance of the November 1, 2021 Sub 175 Submissions.[105] At that time, stakeholders did not express support for further evaluation of competitive price methodologies or further consideration of new methodologies that provide for more accurate avoided energy calculations based upon the utility's avoided cost at the time of delivery.[106] These approaches may be appropriate for further consideration with Public Staff, the Joint Solar Advocates and other stakeholders in the future.

[103] Public Staff Initial Comments, at 24.
[104] 18 C.F.R. 292.304(b)(7).
[105] Duke Energy Joint Initial Statement, at 41.
[106] 18 C.F.R. 292.304(d)(3).

IV. <u>SISC Methodology and Proposed Charges Should be Approved</u>

The Companies' Joint Initial Statement describes the Companies' efforts since the 2018 Sub 158 proceeding to review and develop the updated solar integration services charge ("SISC") methodology and updated study and results presented for inclusion in DEP's and DEC's avoided energy rates in this proceeding.[107] To support the updated SISC calculation methodology, the Companies submitted both the updated 2021 Solar Integration Services Charge Study performed by Astrapé Consulting (the "2021 Astrapé SISC Study")[108] as well as a report prepared by the independent SISC technical review committee ("TRC") analyzing the Companies' proposed solar integration cost methodology ("TRC Report").[109] The TRC's evaluation of the SISC methodology and draft 2021 Astrapé SISC Study report was robust and the TRC report was produced after completing a total of eleven meetings over approximately five months to discuss and analyze these complex issues.

The Public Staff—who participated in the TRC as regulatory observers—finds the proposed SISC methodology to be reasonable and appropriate and comments favorably on the TRC and the SISC methodological improvements undertaken to address issues raised in the Sub 158 avoided costs proceeding.[110] The Public Staff states that it generally agrees with the TRC's findings and recommends that the TRC report be accepted and DEC's and DEP's respective SISCs developed using the 2021 Astrapé Study be approved by the Commission.[111] In the future, the Public Staff also recommends that the Companies

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[107] DEC & DEP Joint Initial Statement, at 31-34.
[108] *Id.* at DEC/DEP Exhibit 11.
[109] *Id.* at DEC/DEP Exhibit 10.
[110] Public Staff Initial Statement, at 20-24.
[111] *Id.* at 45.

consider the effect of the Southeast Energy Exchange Market ("SEEM") on calculation of SISC in any avoided cost filings that occur six months or more after SEEM operations commence.[112] The Companies do not object to the Public Staff's recommendation and commit to considering the impact of SEEM, if any, on the calculation of SISC in any avoided cost proceeding commencing six (6) months or more after approval.

In contrast to Public Staff's support for the TRC's findings and the updated SISC methodology and rate inputs, as calculated in the 2021 Astrapé SISC Study, SACE and its consultant, Mr. Brendan Kirby, identified three purported "flaws" in the proposed methodology that SACE contends inflate the value of the SISC and therefore artificially depress avoided energy costs paid to solar QFs.[113] In particular, SACE argues that (1) the assumption that solar load-following reserves are required before sunrise and after sunset—hours during which there is no solar generation—results in an overcharge to solar QFs for reserves; (2) Astrapé's "combined case" failed to account for the reduction in solar load-following reserves that are required under Joint Dispatch Agreement ("JDA") operations, leading to an overstatement of load-following reserve requirements and artificially increase to the SISC; and (3) the five-minute "flexibility violation" metric is unnecessarily stringent and inappropriate for the SISC analysis.[114] Setting aside the already-reduced SISC resulting from the Companies' determination to utilize the average versus incremental integration costs for new solar QFs,[115] SACE's criticism is unsubstantiated and the updated SISCs—which were developed consistent with the TRC report's findings—are reasonable and should be approved.

[112] Public Staff Initial Statement, at 23-24.
[113] SACE Initial Comments, at 23.
[114] *Id.* at 23-24.
[115] DEC & DEP Joint Initial Statement, at 32 n.75.

A. The 2021 Astrapé SISC Study Appropriately Considered Solar Incremental Load-Following Reserve Requirements

The 2021 Astrapé SISC Study appropriately considered and tested the Companies' load following requirements iteratively to determine the least cost way to resolve flexibility excursions. Mr. Kirby critiques Astrapé's methodology by noting that solar load following reserves should not be required before sunrise and after sunset.[116] However, as described by the TRC and explained below, Astrapé's approach, supported by the TRC, appropriately adjusts load following reserves and achieves the reduction in integration costs that Mr. Kirby is seeking with his recommendation.

As described in the 2021 Astrapé SISC Study, the study's objective was to return flexibility excursions on the DEC and DEP systems back to the base case with no solar. Importantly, the TRC found Astrapé's approach on this issue to be reasonable, "representing a significant improvement over the 2018 study and consistent with how most system operators determine their load following requirements." Among such improvements, the TRC concluded in their final report pertaining to the 2021 Astrapé SISC Study:

- "[T]he current study increases load following reserves on a monthly basis and only during the hours of the day when solar-related flexibility violations are likely to occur each month. This is a different approach than that employed in the 2018 study, which increased reserve requirements by the same amount for all hours of the year. Maintaining no-solar reliability levels and targeting the load following reserves additions to the months and time of day when needed reduces integration costs"; [117]
- "[A]dds load following reserves in a targeted manner and the model calculates the flexibility violations. The simulation is then iterated with

[116] SACE Initial Comments, at 23.
[117] *Id.* at III-13.

adjustments to the added load following reserve amounts to match historical 5-minute flexibility violations";[118]

- "[A]ccounts for the diversity between solar production profiles in different counties throughout the Carolinas, which capture the fact that new solar facilities will come online in different locations";[119] and

- "[I]mplement[s] a targeted approach to only add additional load following reserves in hours when they are most likely needed (i.e., whenever volatility is the highest)[, thus] reduc[ing] the overall estimated integration cost."[120]

With respect to flexibility violations, specifically, Astrapé examined the 12x24 flexibility excursions from the cases with solar and added reserves to remove the aforementioned excursions. Based on this assessment, Astrapé removed some of the flexibility excursions in the pre-solar and post-solar hours. Using this methodology, the overall excursions are still reduced to the level of the no solar Base Case, and the TRC found Astrapé's approach to be a "significant improvement" over the approach used in the previous study. If anything, Astrapé's approach likely favors solar more than SACE's proposal because it allows an increase of excursions to occur across the solar production hours by eliminating excursions in periods where reserves are already low a few hours before and after the solar production hours. If the reserve requirements were tightened as Mr. Kirby suggests, it is likely that excursions would occur in those pre- and post-solar periods, requiring more reserves across the solar production hours which increase solar integration costs.

[118] TRC Report, at IV-17.
[119] *Id.*
[120] *Id.* at IV-18.

B. The 2021 Astrapé SISC Study Appropriately Took into Account the Companies' Operations under the Joint Dispatch Agreement

SACE's second argument—that the "combined case" failed to account for the reduction in solar load-following reserves that are required under the Companies' JDA operations[121]—represents a fundamental misunderstanding of the Companies' operational obligations under the JDA. According to SACE, "the JDA *nets* the DEC and DEP systems' dispatch needs to meet real-time balancing requirements."[122] This is an oversimplification of the JDA arrangement. In fact, while the JDA allows economic exchanges to reduce the *costs* of additional load following requirements, each Balancing Authority ("BA") *must continue to plan for and maintain its own operating reserves*.[123] Accordingly, any model that simply "netted" DEC's and DEP's system dispatch needs would not accurately reflect the relationship between the two utilities under the JDA. Instead, with input from both the TRC and Duke Energy subject matter experts to ensure its model accurately reflected the true operation of the JDA, Astrapé's "combined case" modeled "joint [DEC/DEP] unit commitment and minute-by-minute dispatch subject to applicable transmission limits appropriately modeled its "combined case" to reflect this relationship."[124] In this way, the TRC report explains, "resources in DEC and DEP are jointly committed and dispatched,

[121] SACE Initial Comments, at 24.
[122] *Id.*
[123] *See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct,* Docket Nos. E-2, Sub 998 and E-7, Sub 986, at Appendix A, Regulatory Conditions Section 4.1 (June 29, 2012) (Regulatory Condition 4.1 conditions the approval of the Companies' merger upon the JDA never being interpreted as providing for or requiring: upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA, control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or PEC to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates.).
[124] TRC Report, at III-6; 2021 Astrapé SISC Study, at 34.

but the BAs must satisfy their individual operating reserve requirements, and the model respects the transmission constraint between DEC and DEP."[125]

The 2021 Astrapé SISC Study thus successfully models the JDA through lower fuel and operations costs, while ensuring each Balancing Authority maintains its respective operating reserves.

C. The 2021 Astrapé SISC Study's Modeling Approach to 'Flexibility Violation' was Accepted by the TRC and is not Unreasonably Stringent

The final purported "flaw" identified by SACE's expert—that the 2021 Astrapé SISC Study's five-minute "flexibility violation" metric is unnecessarily stringent and, therefore, inappropriate for the SISC analysis[126]—was already considered by the TRC and is specifically addressed in the TRC report. In particular, the TRC supported Astrapé's approach to assessing flexibility violations, finding that increasing the length of the flexibility violations to ten (10) minutes would result in higher—not lower—integration costs.[127] In direct contrast to SACE's contention, the TRC found that the five-minute flexibility violation "*results in a lower SISC* relative to using a longer flexibility violation."[128] As the TRC found, "adjusting the modeling assumptions to reduce the level of reliability to exactly the amount needed to avoid NERC standards implies eliminating any potential reliability cushion that has historically been provided to customers and giving

[125] TRC Report, at III-6.
[126] SACE Initial Comments, at 24.
[127] Duke Energy Joint Initial Statement, DEC/DEP Exhibit 10, TRC Report, Section I(1) ("Astrapé provided information on the length of flexibility violations (5-min vs. 10-min) to inform whether having the model match historical 10-min flexibility violations, instead of 5- min violations, would significantly alter the results. The addition of solar resources increases the share of longer flexibility violations, which implies the integration costs would be higher if the modeling was forced to match historical 10-minute flexibility violations. Therefore, the approach used by Astrapé results in a lower SISC relative to using a longer flexibility violation.").
[128] *Id.* (emphasis added).

all the benefit of eliminating that cushion entirely to solar resources."[129] Therefore, this recommendation to modify the SISC methodology—which was developed consistent with the review, guidance and recommendations of the TRC—should be rejected.

V. SISC Avoidance Protocols and Process

In their Initial Comments, the Public Staff poses a number of questions regarding the Companies' implementation of the Commission's August 17, 2021 Order Approving SISC Avoidance Requirements and Addressing Solar-Plus Storage Qualifying Facility Installations (the "SISC Avoidance Order") in Docket No. E-100, Sub 158. First, the Public Staff asks the Companies to confirm that the SISC avoidance criteria referenced in their proposed tariffs in this proceeding reflect the use of the approved SISC avoidance methodology.[130] The Companies confirm that DEC's and DEP's Schedule PP as filed in this proceeding reflect the SISC avoidance criteria approved by the Commission in its SISC Avoidance Order.

Second, the Public Staff asks the Companies to "consider including the full SISC avoidance requirements in their respective Schedule PP tariffs[.]"[131] The Companies have reviewed this recommendation and have determined that the level of detail in Schedule PP is reasonable and no modifications to the Schedule PP tariff are needed at this time. Schedule PP presents avoided energy rates for Uncontrolled Solar Generation QFs and states that QFs will be required to execute a negotiated PPA form if they intend to contractually obligate themselves to operate in a controlled manner and to avoid the SISC.[132] If a Schedule PP-eligible QF seeks to contractually obligate itself in a controlled

[129] *See Id*.
[130] Public Staff Initial Statement, at 46–47.
[131] *Id.* at 45–46.
[132] Duke Energy Joint Initial Statement, DEC/DEP Exhibit 1.

manner, the Companies' would work with the QF to enter into a negotiated PPA and would include the SISC avoidance methodology in the negotiated PPA similar to what was incorporated in the recent CPRE Tranche 3 approved PPA.

Finally, the Public Staff recommends that the Commission direct the Companies to, in future avoided costs proceedings, file a report on QFs that attempt to avoid the SISC, and include an analysis of actual solar volatility reductions of QFs that avoid the SISC in the Companies' service territories.[133] The Public Staff correspondingly recommends that the Commission direct the Companies to, in direct testimony in future fuel rider proceedings, address QFs seeking SISC avoidance, providing the specific facilities and amount of SISC credits issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC.[134] With respect to the latter recommendation, the Companies note that the SISC Avoidance Order already requires the Companies to address the SISC avoidance process, including the specific items identified by the Public Staff, in their pre-filed direct testimony in future fuel and fuel-related charge adjustment proceedings.[135] The Companies similarly do not object to Public Staff's request that the Companies report on QFs that obligate themselves to operate in a controlled manner to avoid the SISC in future avoided cost proceedings, including the analysis identified by the Public Staff.

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[133] *Id.* at 46.
[134] *Id.*
[135] SISC Avoidance Order, at 5, 10.

VI. **The Companies' Proposed Revisions to Their Notice of Commitment Form Are Reasonable and Should Be Approved With the Modifications Responsive to NCSEA/CCEBA Identified Herein**

Both the Public Staff and NCSEA/CCEBA indicate that they generally support the Companies' revisions to the Notice of Commitment ("NOC") Forms for standard offer-eligible QFs as well as QFs above one MW not eligible for Schedule PP.[136] In particular, the Public Staff agrees that the revisions appropriately incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872, align the LEO process with the new DISIS process, and establish a more standardized and efficient process for QFs to proceed from an NOC to a PPA.[137] While NCSEA/CCEBA are "generally comfortable" with the proposed revisions, they point out that Section 4 of the Large QF NOC Form—which requires QFs to begin delivering energy to the Companies no later than 365 days after submitting the NOC Form—may not be practicable for QFs seeking new interconnections given the longer lead times required to complete interconnection studies and construct required interconnection facilities. To address this concern, NCSEA/CCEBA propose that the Companies revise Section 4 to instead require such new QFs seeking interconnection to the DEC or DEP systems to begin delivering energy output within 90 days of DEC's or DEP's completion of all required interconnection facilities and network upgrades.

The Companies' intent in revising the Large QF NOC Form was to provide for a different delivery term requirement for existing QFs (with existing interconnection agreements) that have been operational as compared to new interconnection requests for

[136] *See* Duke Energy Joint Initial Statement, Exs. 6 & 7.
[137] *Id.*

QFs that have not yet achieved commercial operation. In light of CCEBA/NCSEA's comments, the Companies have amended Section 4 to further clarify this position.

CCEBA/NCESA has further argued that the Seller should be given day-for-day extensions beyond the 90-day in-service date specified in the interconnection request or interconnection agreement (as applicable) for delays which are not caused by the Seller. The Companies agree that further extensions of the in-service-date may be appropriate where the Seller is making a good faith effort to advance the project but is delayed due to circumstances beyond its control and which do not result from its fault or negligence. Based on the foregoing, the Companies have added the following proviso to Section 4 of the NOC form:

> [P]rovided that Seller is making good faith efforts to advance the project as contemplated in the interconnection request or interconnection agreement and has provided reasonable assurances of such in writing to the Company, Seller shall be given day-for-day extensions on its in-service date for delays to the in-service date which are not caused by or attributable to Seller, or any party under its direction or control, and which do not result from the fault, negligence, act or inaction of Seller or any party under its direction or control.

The Companies updated Large QF NOC Form is being filed as Reply Comments Exhibit 1 and is intended to supersede and replace DEC/DEP Exhibit 7 as initially filed for approval in the Companies' Joint Initial Statement.

VII. The Companies' Energy Storage System Retrofit Rates Are Reasonable and Should Be Approved As Filed

The Commission's *Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations* issued on August 17, 2021 in Docket Nos. E-100, Sub 101 and E-100, Sub 158 (the "Sub 101/158 Storage Retrofit Order") approved a streamlined process for interconnecting and co-locating energy storage systems with existing solar generation facilities. The Sub 101/158 Storage Retrofit Order further directed the Companies to propose a procedure for establishing QF eligibility for the avoided cost rate or methodology applicable to the output of the energy storage addition.[138] While the Commission has not yet approved the Companies' proposed procedure in Docket Nos. E-100, Sub 101 and E-100, Sub 158, DEC and DEP filed New ESS Retrofit avoided cost rates in this proceeding, which will be available to Interconnection Customers proposing to retrofit an energy storage system at an existing solar generation site, for Commission approval as part of its initial Submissions in the instant docket.[139]

The Public Staff finds the Companies' proposed rates (filed in this docket) and eligibility requirements (filed in the Sub 101 and Sub 158 dockets) to be reasonable and recommends that the Commission approve both the Companies' proposed New ESS Retrofit avoided cost rates as well as a bifurcated rate proposal the Public Staff proposed in its Initial Comments in the Sub 158 proceeding.[140] The Companies agree with the Public Staff that their New ESS Retrofit avoided cost rates are reasonable and should be approved, and additionally note that no other intervenor submitted comments on this issue.

The Public Staff's bifurcated rate proposal would require utilities to separately meter any additional energy output from the original facility and compensate the additional output at the then-current Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of the pre-existing PPA.[141] In the Sub 158 proceeding, the Companies opposed this proposal, and all parties, including the Public Staff, acknowledged potential challenges to implementation of the bifurcated rate proposal.

[138] Sub 101/158 Storage Retrofit Order, at 11.
[139] *See* Duke Energy Joint Initial Statement, DEC/DEP Exhibit 12.
[140] Public Staff Initial Statement, at 58-59.
[141] 2018 Sub 158 Order, at 120.

The Commission shared these concerns, noting that "allowing QFs to add storage at bifurcated avoided cost rates raises a multitude of challenging administrative and regulatory issues"[142] and finding that it was "premature" to rule on the Public Staff's proposal absent further "investigation" into the issues."[143]

Beginning in May 2020, the Companies hosted a series of stakeholder meetings to address the multitude of challenging administrative and regulatory issues raised by allowing existing QFs to add storage at bifurcated avoided cost rates pursuant to the Commission's directive in the *Sub 158 Order.*[144] As part of this process, the Companies worked in good faith with stakeholders to achieve technical and regulatory solutions for modifying existing facilities to add energy storage and reached a compromise consensus regarding the Public Staff's proposed bifurcated rate proposal. Specifically, the parties agreed, among other things, that (1) the addition of storage to an existing facility will be accomplished through amendment of the existing PPA, rather than negotiating a new PPA; and (2) metering of the storage addition will be covered by an AC-connected configuration, although integration of DC connected systems will be allowed once DC revenue-grade meters are available and tested.[145] Accordingly, subject to the caveat that only AC-connected configurations can currently be metered,[146] the Companies support the Public Staff's request for the Commission to approve the bifurcated rate proposal.

[142] 2018 Sub 158 Order, at 131.
[143] *Id.*
[144] 2018 Sub 158 Order, at 137 (Ordering Paragraph No. 30).
[145] Joint Report by DEC, DEP, and DENC on Storage Retrofit Stakeholder Meeting, Dkt. No. E-100, Sub 158, at 5 (Sept. 16, 2020); Reply Comments of CCEBA, NCSEA, and SACE, Dkt. No. E-100 Sub 158, at 3 (Nov. 20, 2020); Reply Comments of the Public Staff, Dkt. No. E-100, Sub 158, at 3 (Dec. 16, 2020).
[146] *See* SISC Avoidance Order, at 8 (recognizing the parties' agreement that DC-coupled energy storage systems should be allowed once revenue grade meters are available).

VIII. The Companies Support Limited Modifications to Their Net Energy Metering Tariffs

The Companies filed their Joint Application for Approval of Revised Net Energy Metering Tariffs ("NEM Tariffs") in Docket Nos. E-7, Sub 1214, E-2, Sub 1219, and E-2, Sub 1076 on November 29, 2021. The Companies agree with Public Staff's recommendation to decide the Net Excess Energy Credit ("NEEC") calculation methodology for the NEM Tariffs within this avoided cost docket, Docket No. E-100, Sub 175. The Companies do not dispute the basis for the Public Staff's recommended modifications to the NEEC calculation methodology to improve the accuracy of the avoided cost credit. After analysis, as reflected in Table 1 below, the Companies determined that implementing seasonal rates would have a negligible impact on the NEEC avoided cost credit. This is evidenced by the small differentiation between summer and non-summer rates in Table 1: 5% in both DEC and DEP. The other parties to the Memorandum of Understanding ("MOU"), filed in Docket No. E-100, Sub 180 on November 29, 2021, have raised concerns to the Companies about adding further complexity to the proposed NEM Tariffs.[147] The Companies share this concern. Given the negligible impact and the concerns of the Companies and the parties to the MOU regarding the added complexity of the proposal, the Companies therefore recommend that the Commission adopt the annualized, rather than seasonal, rate option. The Companies would agree to calculate seasonal NEEC rates within avoided cost proceedings for analytical purposes and to consider switching to seasonal NEEC rates if the differentiation

[147] These settling parties include NCSEA, Southern Environmental Law Center on behalf of Vote Solar and SACE, Sunrun, Inc., and Solar Energy Industries Association.

between summer and non-summer seasons becomes sufficiently impactful to outweigh the added complexity.

With respect to the remaining modifications proposed by Public Staff, the Companies have agreed to support annualized NEEC rates based on a 5-year term, including both energy and capacity credits where applicable, and weighted using a typical rooftop solar production profile.

In the future, the Companies may recommend switching to a typical NEM export profile rather than a gross rooftop solar production profile. This is an important clarification, because the NEEC should reflect the average value of excess exports from NEM systems, which have a unique profile impacted by self-consumption. However, the Companies recognize that there may not be adequate information about customer usage patterns on the NEM Tariffs and associated time-of-use rate schedules to generate an applicable NEM export profile at this time.

Table 1: Recalculated Net Energy Excess Credit Rates

(cents per kWh)	**Time Period**	**DEC**	**DEP**
Public Staff's proposed methodology	Summer (May-Sept)	3.43	3.32
	Non-Summer (Oct-Apr)	3.27	3.49
The Companies' revised proposed methodology	Full Year	3.35	3.40

The Companies are attaching as Exhibit 2 to these Reply Comments a supplemental filing providing re-calculated NEEC rates consistent with the Companies' revised proposed methodology described above.

CONCLUSION

WHEREFORE, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission approve:

1. The Companies' respective updated Schedule PP avoided cost rates and terms and conditions, as presented in the Joint Initial Statement;
2. The Companies' modified Large QF Notice of Commitment Form presented as DEC/DEP Reply Comments Exhibit 1;
3. The Companies' ESS Retrofit Rates and the Public Staff's bifurcated rate proposal subject to metering of the storage addition by an AC-connected configuration;
4. The Companies' recalculated NEM Tariff NEEC rates presented as DEC/DEP Reply Comments Exhibit 2; and
5. Any further relief the Commission deems to be just and reasonable and in the public interest.

Respectfully submitted,

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DEC / DEP Reply Comments Exhibit 1

Reply Comments Exhibit 1 Clean and Redlined Large QF Notice of Commitment Form

Docket No. E-100, Sub 175

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY GREATER THAN 1MW$_{AC}$ TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

(North Carolina)

This notice of commitment form establishes a binding legally enforceable obligation ("LEO") on behalf of a qualifying facility ("QF") with a nameplate capacity greater than 1 MW$_{AC}$, further described as "Seller" below, committing to sell and deliver the output of a proposed QF generating facility to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") as provided for in N.C. Gen. Stat. § 62-156(b) and 18 C.F.R. 292.304(d)(3).

The QF shall deliver, via email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy Technologies
Attn.: Wholesale Renewable Contract Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same email address specified above.

This form may also be used by a QF proposing to materially alter its generating facility to integrate an energy storage system and committing to sell the output of the modified generating facility to the Company. Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.

Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ____________________
Contact Person: ____________________ Telephone: ________________________
Address: ________________________ Email: ___________________________

By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of the Facility for the Delivery Term (together will all completed Attachments hereto, the "Notice of Commitment"), Seller certifies as follows and is providing the following documentation to the Company:

1. Seller meets the requirements and has obtained certification from the Federal Energy Regulatory Commission ("FERC") to operate as a QF. Seller is providing documentation in Attachment A demonstrating the following:

   A. Seller has obtained self-certification of QF status filed with the FERC in Docket No. QF __________ (the "Facility"), or is otherwise providing documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207; or,

B. If participating in the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC Energy Storage System Retrofit Study Process, Seller is proposing to materially alter an existing QF to integrate an energy storage system to be fueled by the QF and has obtained certification of the modified QF in Docket No. QF __________ and has provided the new QF self-certification and written notice of the QF's commitment to construct the energy storage system to the North Carolina Utilities Commission ("Commission") in Docket No.__________ where the QF's Certificate of Public Convenience and Necessity was originally issued.

Seller shall also provide in Attachment A documentation for all other QFs located within one mile of the project or within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

2. Seller's QF is currently operating or is proposed to be constructed and to interconnect to the Company's system at the location described in Attachment B (the "Project Site"). If Seller is not directly interconnected to the Company's System, Seller shall be responsible for making all necessary transmission arrangements with its interconnected electric utility to deliver its power to the Company pursuant to 18 C.F.R. 292.303(d).

3. Seller shall also provide in Attachment B all material information required for the Company to provide Seller an executable power purchase agreement within 30 days of the date of this notice of commitment. If information provided by Seller is not sufficient, the Company shall provide the Seller written notice providing an opportunity to cure such failure by the close of business on the tenth (10) business day following the posted date of such notice. The failure to provide the information requested within this period shall result in the Notice of Commitment being terminated pursuant to Section 8.

4. Commitment to Sell Power for Specified Future Delivery Term. Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years] (the "Delivery Term") as follows: (a) where Seller's QF is currently interconnected to the Company's System, within 365 days of the Submittal Date (as defined below), and (b) where the Seller is a new Interconnection Customer of the Company (or where a new interconnection request is submitted for an interconnected QF Seller which includes a new in-service date), by a date that is no later than 90 days after the in-service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company. Provided that Seller is making good faith efforts to advance the project as contemplated in the interconnection request or interconnection agreement and has provided reasonable assurances of such in writing to the Company, Seller shall be given day-for-day extensions on its in-service date for delays to the in-service date which are not caused by or attributable to Seller, or any party under its direction or control, and which do not result from the fault, negligence, act or inaction of Seller or any party under its direction or control.. By execution of this Form, Seller represents that the QF is commercially viable and financially committed to delivering its full electrical output to the Company for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

5. The documents attached hereto as Attachment C are provided to demonstrate Seller's commercial viability and financial commitment to sell and deliver power as of the Submittal Date for the future Delivery Term.

6. The mutually-binding legally enforceable obligation established by this Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

7. LEO Date. By execution and submittal of this Notice of Commitment, Seller acknowledges that the date of the QF's binding legally enforceable obligation date to sell the Facility's full capacity and energy output to the Company ("LEO Date") will be the Submittal Date. Rates for purchases from the Seller's QF Facility will be based on the Company's avoided costs as of the LEO Date, calculated using data current as of the LEO Date.

8. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect in each of the following circumstances:

   a. Upon execution of a PPA between Seller and Company.

   b. If Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue.

   c. If Seller does not execute a PPA within 90 days after the Company delivers an executable PPA to the Seller that contains all information necessary for execution and which the Company has requested the Seller to execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Facilities Study Agreement from Company. Notwithstanding the foregoing, if the PPA proposed by the Company becomes the subject of arbitration or complaint proceeding, the deadline for execution of the PPA shall be tolled upon the filing of the pleading commencing such proceeding and thereafter the deadline for execution of the PPA will be as directed by the Commission.

   d. If the Seller ceases to have control of the Project Site; ceases to be certified as a QF with FERC or ceases to be certificated by the Commission, if required, and any such deficiency has not been cured within ten (10) business days of written notice by the Company.

e. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period, as identified in subsection 8.(c) above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

I swear or affirm, in my capacity as a duly-appointed officer of the Seller, that I have personal knowledge of the facts and information presented in this Notice of Commitment, I am competent to testify to those facts, and I have authority to make this binding legally enforceable obligation to the Company on behalf of Seller. I further swear or affirm that all of the statements and representations made in this Notice of Commitment are true and correct as of the date hereof. I further swear or affirm that Seller will comply will all requirements of this Notice of Commitment.

____
[Name]

____
[Title]

____
[Company]

____
[Date]

Attachment A to Notice of Commitment Form

[*Seller Information, QF Certification, and Affiliated QFs*]

1. Seller Information. The name, address, and contact information for Seller is:

   Name: ___________________________ Telephone: _________________________

   Address: _________________________ Email: _____________________________

2. Seller is providing its QF self-certification or other documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207.

3. Seller is providing the QF self-certification or other documentation for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller. Seller shall also provide a description of the organizational structure and chart of upstream developer, if applicable, and describe the affiliate relationship between Seller and other QFs within 10 miles of the project.

Attachment B to Notice of Commitment Form

[*Information Required to Complete PPA*]

The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and commits to provide Seller an executable PPA within 30 days of receipt of all project information reasonably required for the development of the PPA, including, but not limited to:

a. Facility Name and address of Project Site;
b. Description of Facility (include number, manufacturer and model of Facility generating units, and layout). Also, describe if storage is included;
c. Generation technology and other related technology applicable to the Facility;
d. Fuel type (s) and source (s);
e. Plans to obtain, or actual fuel and transportation agreements, if applicable;
f. Maximum design capacity AC and DC (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;
g. Site Map (include location and layout of the Facility, equipment, and other site details for the Project Site);
h. Delivery Point Diagram (include Delivery Point, metering, Facility substation)
i. Where QF is or will be interconnected to an electrical system other than the Company's, plans to obtain, or actual electricity transmission agreements with the interconnected system to deliver power to Company;
j. Quantity, firmness, and timing of daily and monthly power deliveries, including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;
k. Ability, if any, of QF to respond to dispatch orders from the Company and, if applicable, whether solar QF plans to operate facility as a Controlled Solar Generator*;
l. Anticipated commencement date for delivery of electric output;
m. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;
n. Interconnection Agreement status and estimated date for execution of Interconnection Agreement;
o. Estimated date for Financing Commitment*,
p. Estimated date for Final System Design* under Interconnection Agreement
q. Estimated date for Commencement Readiness Requirements* and
r. Proposed contracting term for the sale of electric output to the Company.

*Capitalized terms unless defined herein shall have the same meaning specified in the Companies' negotiated form of power purchase agreement for large QFs above 1MW accessible on [Duke website], unless otherwise specified herein.

Attachment C to Notice of Commitment Form

[*Information Required to Demonstrate Commercial Viability and Financial Commitment*]

Seller provides the following information in order to demonstrate commercial viability and financial commitment to sell and deliver power over the specified Delivery Term

1. Certificate of Public Convenience and Necessity; or Report of Proposed Construction.

   a. ____Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _____ kW (net capacity$_{ac}$) Facility from the NCUC pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. ____.

   b. _____ Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its ____ kW (net capacity$_{ac}$) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. ___.

   c. _____ Seller is proposing to co-locate an _____ kW (net capacity$_{ac}$) energy storage system at a generating facility that previously obtained a CPCN for the construction of a _____ kW (net capacity$_{ac}$) QF generating facility in Docket No. ____ and the QF has provided written notice to the NCUC of the planned energy storage addition to the QF.

2. Interconnection – Reasonable evidence that Seller is interconnected to the Company's system, has made transmission arrangements to deliver its power to the Company's system, or has requested to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and the Seller has met all applicable requirements to commence the interconnection study process under the Definitive Interconnection Study Process, including without limitation providing the Section 4.4.1 initial security requirement and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5.

3. Site Control – Reasonable evidence of site control for the entire contracting term

4. Project Development – Please provide a current status update on the development of the Facility, including anticipated timelines for:
   a. completion of key QF milestones specified in Attachment B,
   b. proof of payment of applicable permitting and other application fees,
   c. the procurement of any long-lead time materials,
   d. execution of construction agreements or EPC contracts to construct the Facility,
   e. execution of third-party Transmission Agreements and other agreements or events necessary to achieve commercial operation of the facility within 365 days of the Submittal Date.

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY GREATER THAN 1MW$_{AC}$ TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

(North Carolina)

This notice of commitment form establishes a binding legally enforceable obligation ("LEO") on behalf of a qualifying facility ("QF") with a nameplate capacity greater than 1 MW$_{AC}$, further described as "Seller" below, committing to sell and deliver the output of a proposed QF generating facility to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") as provided for in N.C. Gen. Stat. § 62-156(b) and 18 C.F.R. 292.304(d)(3).

The QF shall deliver, via email, its executed Notice of Commitment

to: Duke Energy – Distributed Energy Technologies
Attn.: Wholesale Renewable Contract Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same email address specified above.

This form may also be used by a QF proposing to materially alter its generating facility to integrate an energy storage system and committing to sell the output of the modified generating facility to the Company. Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.

Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ____________________
Contact Person:____________________ Telephone:________________________ Address:___

By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of the Facility for the Delivery Term (together will all completed Attachments hereto, the "Notice of Commitment"), Seller certifies as follows and is providing the following documentation to the Company:

1. Seller meets the requirements and has obtained certification from the Federal Energy Regulatory Commission ("FERC") to operate as a QF. Seller is providing documentation in ~~A ttachment~~Attachment A demonstrating the following:

   A. Seller has obtained self-certification of QF status filed with the FERC in Docket No. QF__________(the "Facility"), or is otherwise providing documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207; or,

   B. If participating in the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC Energy Storage System Retrofit Study Process, Seller is proposing to materially alter an existing QF to integrate an energy storage system to be fueled by the QF and has obtained certification of the modified QF in Docket No. QF__ and has provided the new QF self-certification and written notice of the QF's commitment to construct the energy storage system to the North Carolina Utilities Commission ("Commission") in Docket No.____where the QF's Certificate of Public Convenience and Necessity was originally issued.

Seller shall also provide in Attachment A documentation for all other QFs located within one mile of the project or within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

2. Seller's QF is currently operating or is proposed to be constructed and to interconnect to the Company's system at the location described in Attachment B (the "Project Site"). If Seller is not directly interconnected to the Company's System, Seller shall be responsible for making all necessary transmission arrangements with its interconnected electric utility to deliver its power to the Company pursuant to 18 C.F.R. 292.303(d).

3. Seller shall also provide in Attachment B all material information required for the Company to provide Seller an executable power purchase agreement within 30 days of the date of this notice of commitment. If information provided by Seller is not sufficient, the Company shall provide the Seller written notice providing an opportunity to cure such failure by the close of business on the tenth (10) business day following the posted date of such notice. The failure to provide the information requested within this period shall result in the Notice of Commitment being terminated pursuant to Section 8.

4. Commitment to Sell Power for Specified Future Delivery Term. Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years] (the "Delivery Term") as follows: (a) where Seller's QF is currently interconnected to the Company's System, within 365 days of the Submittal Date (as defined below), ~~except~~and (b) where the Seller is a new Interconnection Customer of the Company ~~and its failure to begin delivery of power within 365 days is due to the time required for the Company to complete needed interconnection facilities or system upgrades by~~(or where a new interconnection request is submitted for an interconnected QF Seller which includes a new in-service date), by a date that is no later than 90 days after the in-service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company. Provided that Seller is making good faith efforts to advance the project as contemplated in the interconnection request or interconnection agreement and has provided reasonable assurances of such in writing to the Company,~~ for which the~~ Seller shall be given day-for-day extensions on its in-service date for ~~any~~ delays to the in-service date which are not caused by or attributable to ~~the in-service date of these interconnection facilities or system upgrades~~Seller, or any party under its direction or control, and which do not result from the fault, negligence, act or inaction of Seller or any party under its direction or control.. By execution of this Form, Seller represents that the QF is commercially viable and financially committed to delivering its full electrical output to the Company for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

5. The documents attached hereto as Attachment C are provided to demonstrate Seller's commercial viability and financial commitment to sell and deliver power as of the

Submittal Date for the future Delivery Term.

6. The mutually-binding legally enforceable obligation established by this Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

7. LEO Date. By execution and submittal of this Notice of Commitment, Seller acknowledges that the date of the QF's binding legally enforceable obligation date to sell the Facility's full capacity and energy output to the Company ("LEO Date") will be the Submittal Date. Rates for purchases from the Seller's QF Facility will be based on the Company's avoided costs as of the LEO Date, calculated using data current as of the LEO Date.

8. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect in each of the following circumstances:

   a. Upon execution of a PPA between Seller and Company.

   b. If Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue.

   c. If Seller does not execute a PPA within 90 days after the Company delivers an executable PPA to the Seller that contains all information necessary for execution and which the Company has requested the Seller to execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Facilities Study Agreement from Company. Notwithstanding the foregoing, if the PPA proposed by the Company becomes the subject of arbitration or complaint proceeding, the deadline for execution of the PPA shall be tolled upon the filing of the pleading commencing such proceeding and thereafter the deadline for execution of the PPA will be as directed by the Commission.

   d. If the Seller ceases to have control of the Project Site; ceases to be certified as a QF with FERC or ceases to be certificated by the Commission, if required, and any such deficiency has not been cured within ten (10) business days of written notice by the Company.

   e. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period, as identified in subsection 8.(c) above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

I swear or affirm, in my capacity as a duly-appointed officer of the Seller, that I have personal knowledge of the facts and information presented in this Notice of Commitment, I am competent to testify to those facts, and I have authority to make this binding legally enforceable obligation to the Company on behalf of Seller. I further swear or affirm that all of the statements and representations made in this Notice of Commitment are true and correct as of the date hereof. I further swear or affirm that Seller will comply will all requirements of this Notice of Commitment.

____

[Name]

____

[Title]

____

[Company]

____

[Date]

Attachment A to Notice of Commitment Form

[*Seller Information, QF Certification, and Affiliated QFs*]

~~1.~~

~~S eller~~

1. Seller Information. The name, address, and contact information for Seller is:

Name:____________________________ Telephone:_________________________

Address:__________________________ Email:_____________________________

2. Seller is providing its QF self-certification or other documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207.

3. Seller is providing the QF self-certification or other documentation for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller. Seller shall also provide a description of the organizational structure and chart of upstream developer, if applicable, and describe the affiliate relationship between Seller and other QFs within 10 miles of the project.

Attachment B to Notice of Commitment Form

[*Information Required to Complete PPA*]

The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and commits to provide Seller an executable PPA within 30 days of receipt of all project information reasonably required for the development of the PPA, including, but not limited to:

a. Facility Name and address of Project Site;
b. Description of Facility (include number, manufacturer and model of Facility generating units, and layout). Also, describe if storage is included;
c. Generation technology and other related technology applicable to the Facility;
d. Fuel type (s) and source (s);
e. Plans to obtain, or actual fuel and transportation agreements, if applicable;
f. Maximum design capacity AC and DC (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;
g. Site Map (include location and layout of the Facility, equipment, and other site details for the Project Site);
h. Delivery Point Diagram (include Delivery Point, metering, Facility substation)
i. Where QF is or will be interconnected to an electrical system other than the Company's, plans to obtain, or actual electricity transmission agreements with the interconnected system to deliver power to Company;
j. Quantity, firmness, and timing of daily and monthly power deliveries, including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;
k. Ability, if any, of QF to respond to dispatch orders from the Company and, if applicable, whether solar QF plans to operate facility as a Controlled Solar Generator*;
l. Anticipated commencement date for delivery of electric output;
m. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;
n. Interconnection Agreement status and estimated date for execution of Interconnection Agreement;
o. Estimated date for Financing Commitment*,

p. Estimated date for Final System Design* under Interconnection Agreement
q. Estimated date for Commencement Readiness Requirements* and
r. Proposed contracting term for the sale of electric output to the Company.

*Capitalized terms unless defined herein shall have the same meaning specified in the Companies' negotiated form of power purchase agreement for large QFs above 1MW accessible on [Duke website], unless otherwise specified herein.

Attachment C to Notice of Commitment Form

[*Information Required to Demonstrate Commercial Viability and Financial Commitment*]

Seller provides the following information in order to demonstrate commercial viability and financial commitment to sell and deliver power over the specified Delivery Term

1. ~~. C ertificate~~Certificate of Public Convenience and Necessity; or Report of Proposed Construction.

   a. Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _ kW (net capacity$_{ac}$) Facility from the NCUC pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. .

   b. Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its kW (net capacity$_{ac}$) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. .

   c. _____ Seller is proposing to co-locate an ~~—~~______kW (net capacity$_{ac}$) energy storage system at a generating facility that previously obtained a CPCN for the construction of a ____ kW (net capacity$_{ac}$) QF generating facility in Docket No.__and the QF has provided written notice to the NCUC of the planned energy storage addition to the QF.

~~2. .~~

~~3. .~~

~~4. .~~

~~I nterconnection~~

2. Interconnection – Reasonable evidence that Seller is interconnected to the Company's system, has made transmission arrangements to deliver its power to the Company's system, or has requested to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and the Seller has met all applicable requirements to commence the interconnection study process under the Definitive Interconnection Study Process, including without limitation providing the Section 4.4.1 initial security requirement and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5.

3. ~~S ite~~Site Control – Reasonable evidence of site control for the entire contracting term

4. ~~P roject~~Project Development – Please provide a current status update on the development of the Facility, including anticipated timelines for:
   a. completion of key QF milestones specified in Attachment B,
   b. proof of payment of applicable permitting and other application fees,
   c. the procurement of any long-lead time materials,
   d. execution of construction agreements or EPC contracts to construct the Facility,
   e. execution of third-party Transmission Agreements and other agreements or events necessary to achieve commercial operation of the facility within 365 days of the Submittal Date.

DEC / DEP Reply Comments Exhibit 2

Reply Comments Exhibit 2
Proposed Net Excess Energy Credit

Docket No. E-100, Sub 175

DUKE ENERGY CAROLINAS, LLC
Proposed Net Excess Energy Credit
-

INTERCONNECTED TO: DISTRIBUTION SYSTEM

Line No.	Description		NEEC (A,B) Cents per KWH	
1	Energy Credit	Summer Premium Peak	3.89	(a)1
2	Energy Credit	Summer PM Peak	3.81	(a)2
3	Energy Credit	Summer Off Peak	3.33	(a)3
4	Energy Credit	Winter Premium Peak	5.30	(a)4
5	Energy Credit	Winter AM Peak	4.75	(a)5
6	Energy Credit	Winter PM Peak	4.53	(a)6
7	Energy Credit	Winter Off Peak	3.93	(a)7
8	Energy Credit	Shoulder Peak	3.88	(a)8
9	Energy Credit	Shoulder Off Peak	2.69	(a)9
10				
11	Capacity Credit	Summer PM	0.00	(b)1
12	Capacity Credit	Winter AM	0.00	(b)2
13				
14				
15	Annualized NEEC Energy Credit		3.35	
16	Annualized NEEC Capacity Credit		0.00	
17	**Annualized Total NEEC Credit for NEM tariff** (C)		**3.35**	

Note A Rates are based on based on 5-year avoided costs
Note B Rates include the a Solar Integration Services Charge of $1.05/MWH
Note C Calculation of Annualized Numbers

	NEM Energy			NEM Capacity	
Summer Premium Peak	66	(c)1	Summer PM	26	(d)1
Summer PM Peak	197	(c)2	Winter AM	41	(d)2
Summer Off Peak	291	(c)3			
Winter Premium Peak	7	(c)4		67	
Winter AM Peak	14	(c)5			
Winter PM Peak	1	(c)6			
Winter Off Peak	214	(c)7			
Shoulder Peak	104	(c)8			
Shoulder Off Peak	494	(c)9			
	1,387	(e)			

Annualized NEEC Energy Credit ((a1 * c1) + (a2 * c2) + (a3 * c3) + (a4 * c4) + (a5 * c5) + (a6 * c6) + (a7 * c7) + (a8 * c8) + (a9 * c9)) / (e)
Annualized NEEC Capacity Credit ((b1 * d1) + (b2 * d2) / (e)
Annualized Total NEEC Credit for NEM tariff (C)

DUKE ENERGY PROGRESS, LLC
Proposed Net Excess Energy Credit

-

INTERCONNECTED TO: DISTRIBUTION SYSTEM

Line No.	Description		NEEC (A,B) Cents per KWH	
1	Energy Credit	Summer Premium Peak	3.91	(a)1
2	Energy Credit	Summer PM Peak	3.55	(a)2
3	Energy Credit	Summer Off Peak	3.24	(a)3
4	Energy Credit	Winter Premium Peak	6.05	(a)4
5	Energy Credit	Winter AM Peak	4.47	(a)5
6	Energy Credit	Winter PM Peak	4.94	(a)6
7	Energy Credit	Winter Off Peak	4.00	(a)7
8	Energy Credit	Shoulder Peak	3.73	(a)8
9	Energy Credit	Shoulder Off Peak	2.88	(a)9
10				
11				
12	Capacity Credit	Winter AM	5.80	(b)1
13				
14				
15	Annualized NEEC Energy Credit		3.35	
16	Annualized NEEC Capacity Credit		0.06	
17	**Annualized Total NEEC Credit for NEM tariff**		**3.40**	

Note A Rates are based on based on 5-year avoided costs
Note B Rates include the a Solar Integration Services Charge of $2.26/MWH
Note C Calculation of Annualized Numbers

	NEM Energy			NEM Capacity	
Summer Premium Peak	66	(c)1			
Summer PM Peak	145	(c)2	Winter AM	14	(d)1
Summer Off Peak	342	(c)3			
Winter Premium Peak	7	(c)4		14	
Winter AM Peak	35	(c)5			
Winter PM Peak	0	(c)6			
Winter Off Peak	193	(c)7			
Shoulder Peak	71	(c)8			
Shoulder Off Peak	527	(c)9			
	1,387	(e)			

Annualized NEEC Energy Credit	((a1 * c1) + (a2 * c2) + (a3 * c3) + (a4 * c4) + (a5 * c5) + (a6 * c6) + (a7 * c7) + (a8 * c8) + (a9 * c9)) / (e)
Annualized NEEC Capacity Credit	(b1 * d1) / (e)
Annualized Total NEEC Credit for NEM tariff	