McGuireWoods

McGuireWoods LLP
501 Fayetteville St.
Suite 500
Raleigh, NC 27601
Phone: 919.755.6600
Fax: 919.755.6699
www.mcguirewoods.com

E. Brett Breitschwerdt
Direct: 919.755.6563
bbreitschwerdt@mcguirewoods.com

March 27, 2024

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 194

Dear Ms. Dunston:

Enclosed for filing in the above-captioned docket are the Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC.

Please feel free to contact me if you have any questions.

Very truly yours

/s/ E. Brett Breitschwerdt

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 194

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2023	))))))	**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"), pursuant to the Commission's August 7, 2023 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("2023 Scheduling Order") and subsequent order granting extension of time, and hereby submit their Reply Comments in response to the initial comments filed by the Public Staff – North Carolina Utilities Commission ("Public Staff"), the North Carolina Attorney General's Office ("AGO"), the North Carolina Sustainable Energy Association ("NCSEA"), the Southern Alliance for Clean Energy ("SACE"), and the Carolinas Clean Energy Business Alliance ("CCEBA").

INTRODUCTION

I. The Companies' Avoided Cost Rates are Just and Reasonable for Consumers and Non-Discriminatory to QFs

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

(“PURPA”)[1] and to review the methodology used to fix avoided cost rates to ensure continuing compliance with applicable Federal Energy Regulatory Commission (“FERC”) regulations,[2] as well as North Carolina’s PURPA implementation framework, N.C. Gen. Stat. § 62-156.[3] As explained in their Joint Initial Statement, the Companies engaged in significant discussions with the Public Staff, Dominion Energy North Carolina (“DENC”), and other stakeholders in advance of filing their avoided cost rates in the 2021 avoided cost proceeding (the “2021 Sub 175 Proceeding”) in an attempt to achieve consensus for a standardized approach to calculate their avoided costs and to minimize the number of contested issues in the 2021 Sub 175 Proceeding and future avoided cost proceedings. The Commission approved the Companies’ refinements to their standardized avoided costs calculation approach in its November 22, 2022 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 175 (the “Sub 175 Order”), and the Companies have carried that standardized approach forward in preparing their proposed avoided cost rates in this docket.

The success of the Companies’ standardized approach is apparent from the relatively limited number of issues that are currently in dispute. Importantly, the Public Staff advocates for the Commission to approve the Companies’ avoided capacity and energy rates subject to certain minor recommendations to be addressed in future proceedings and as discussed herein. While the AGO, CCEBA, NCSEA, and SACE

---

[1] 16 U.S.C.A. § 824a-(3).

[2] 18 C.F.R. § 292.304.

[3] N.C. Gen. Stat. § 62-156(b); *see also Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing*, Docket No. E-100, Sub 194 (Aug. 7, 2023) (describing purpose of proceeding as to “facilitate the determination of avoided cost rates” consistent with FERC’s regulations and pursuant to N.C.G.S. § 62-156).

propose some additional modifications to be adopted in the instant proceeding or shortly thereafter, the number and scope of avoided cost issues in dispute has significantly decreased over time. The significant issues raised for the Commission's consideration that would impact the Companies' avoided cost rates and tariffs in *this* proceeding are limited to assessing (1) whether to incorporate an avoidable cost of carbon emissions into the Companies' administratively determined avoided cost rates; (2) the appropriate base or reference portfolio for developing avoided cost rates; (3) the appropriate capacity value and rate design applicable to solar QFs; and (4) the appropriate methodology for calculating the net excess energy credit ("NEEC").

This narrowing of disputed issues is not surprising when viewed in the larger context of the State's evolving approach to adding solar and other renewable energy resources to the grid. While PURPA was initially established decades ago to reduce barriers to independent development of solar generation and other technologies, North Carolina has embraced and substantially "encouraged" clean energy technologies such that solar developers now have multiple avenues by which to sell energy to the Companies and other utilities in this state. While must-take PURPA contracts remain available, in initially passing Session Law 2017-192 ("HB 589") and now Session Law 2021-167 ("HB 951"), the North Carolina General Assembly implicitly confirmed that competitive procurements of renewable energy are now the preferred method of contracting for new solar resources in this State.[4] The competitive prices available through a competitive procurement of renewable resources ("CPRE") provide benefits to all parties by fairly compensating QFs

[4] FERC has also recently recognized in Order No. 872 the role of competitive solicitations in establishing pricing for QF purchases that is fair to QFs and sets just and reasonable rates for utility customers. *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 172 FERC ¶ 61,041 at ¶¶ 427-33 (July 16, 2020) ("Order No. 872").

while reducing the risk that a QF will be over- or under-paid for the energy it generates and delivers to the Companies and customers.[5] Solar competitively procured under HB 951 also provides the Companies and their customers with expanded benefits in terms of operational dispatch and control of purchased power resources as well as rights to the renewable and environmental attributes that otherwise would not transfer to the Companies under a traditional must-take PURPA contract.[6]

The Companies are committed to procuring significant new solar generation, including from QFs, as part of a reliable and least cost portfolio of resources to meet the State's future energy needs. Indeed, under the current 2023-2024 Carbon Plan and Integrated Resource Plan ("CPIRP"), the Companies are proposing near-term actions to procure 6,460 MW of incremental solar generation over the next three years. This is in addition to the approximately 2,800 MW of solar currently in development, for a total of over 9,250 MW of new solar to be placed into service by 2031.[7] Additionally, the Companies have developed and proposed new voluntary customer programs for both large and small customers as well as innovative grid edge programs and evolved net energy metering offerings to meet customers' energy needs. This evolving marketplace and robust encouragement of renewable energy in North Carolina counsels that the statutory purpose

---

[5] Order No. 872 at ¶ 420 (explaining that "[a] competitive solicitation may more accurately value QF capacity over time by subjecting it to competition with other sources").

[6] *See* N.C.G.S. § 62-110.9(2)(b) (providing that solar purchased power contracts entered into under HB 951 shall include "solar energy, capacity, and environmental and renewable attributes" and provide the purchasing utility "rights to dispatch, operate, and control the solicited solar energy facilities in the same manner as the utility's own generating resources"); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 81, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("Sub 148 Order") (stating "[d]uring any system emergency, a utility may discontinue purchases from a qualifying facility if such purchases would contribute to such emergency" under 18 C.F.R. § 292.307(b)(1)).

[7] Supplemental Planning Analysis at 47-48 (Table SPA 4-1), Docket No. E-100, Sub 190 (filed Jan. 31, 2024).

of this proceeding should remain to "determine . . . standard contract avoided cost rates" and approve updated tariffs for mandatory power purchases from QFs up to 1,000 kilowatts based on a reasonable methodology that accurately reflects the Companies' avoided costs.[8] The Companies are committed to ensuring that their PURPA implementation framework and avoided cost rates remain just and reasonable to consumers that are required to purchase QF power as well as non-discriminatory to QFs consistent with Order No. 872 and FERC implementing regulations. Accordingly, the Companies' rates, tariffs and avoided cost methodology proposed in this biennial proceeding are consistent with North Carolina law, accomplish PURPA's objectives, and should be approved by the Commission without modification as further addressed herein.

REPLY COMMENTS

I. Avoided Cost Rate Methodology

A. The Peaker Method Remains the Appropriate Methodology by Which to Calculate the Companies' Avoided Energy and Capacity Costs.

As explained in the Companies' Joint Initial Statement, the peaker method continues to be widely accepted throughout the industry as a reasonable and appropriate methodology for calculating a utility's avoided costs.[9] This Commission has consistently approved the Companies' continued use of the peaker method, including most recently in the 2021 Sub 175 Proceeding where its use was approved as part of the Companies' standardized methodology for deriving DEC's and DEP's forecasted avoided costs. In this proceeding, the Public Staff has indicated its support for the Companies' continued use of

[8] N.C.G.S. 62-156(b)(1).

[9] Joint Initial Statement at 11-12.

the peaker method[10] and no other party challenged its use to calculate the avoided energy and capacity costs that are now before the Commission.[11] In the absence of any opposition to the Companies' continued use of the peaker method in this proceeding, the Companies request that the Commission approve its continued use.

With respect to future proceedings, CCEBA is alone in arguing that the Commission should either (1) direct the Companies and DENC to initiate a stakeholder process for the purpose of "*fully* consider[ing] all alternatives to the peaker method[;]"[12] or (2) schedule a technical conference or evidentiary hearing to "provide an opportunity for the Commission to receive information related to this issue from multiple sources."[13] Despite CCEBA's claims to the contrary, however, the Companies *fully* considered alternatives to the peaker method in the months leading up to their November 1, 2023 avoided cost filing in this docket. Indeed, the Companies Joint Initial Statement explained that of the three non-exclusive potential methodologies for calculating a utility's avoided cost identified in FERC Order No. 872—Locational Marginal Price, Competitive Price, and Competitive Solicitation Price—none are more appropriate for calculating the Companies' avoided costs than the peaker method at this time. The Companies already use a proxy to the Locational Marginal Price model to calculate their As-Available Rate and FERC's regulations make clear that the Competitive Price method is specific to the

[10] Initial Statement of the Public Staff ("Public Staff Comments") at 50 (recommending the Commission "approve Duke avoided energy and capacity rate methods[.]").

[11] The AGO supports continued use of the peaker method on the condition that it is used "to account for the value of carbon emissions reductions[.] However, if the Commission . . . finds it is not possible to accurately reflect carbon emissions reductions using the peaker method, then N.C.G.S. § 62-110.9 and PURPA require the Commission to discontinue the use of the peaker methodology[.]" AGO Comments at 14-15.

[12] CCEBA Comments at 5.

[13] *Id.*

calculation of as-available rates.[14] Similarly, using a Competitive Solicitation Price to determine avoidable cost would be a significant change to establishing the Companies' avoided cost as the Commission would no longer set an administratively-determined avoided cost rate for must-take capacity and energy offered by QFs. To the extent a QF desires to receive a purely market-based rate, it can elect to participate in the robust annual CPRE process established under HB 951 and supervised by the Commission.

Continued use of the Commission-approved peaker method to calculate the Companies' forecasted avoided costs of capacity and energy is consistent with the Companies' current, standardized approach to calculating avoided costs under N.C.G.S. § 62-156(b) and (c), remains non-discriminatory to QFs and just and reasonable to the electric consumer and in the public interest at this time.[15] The biennial cadence in which the Commission reviews the utilities' avoided cost rates provides ample and regular opportunity for the Companies to re-assess and for the Commission to review this issue. Since CCEBA has not proposed or otherwise advocated for any alternative to the peaker method, there is no alternate proposal for the Commission to evaluate in this proceeding. For all of these reasons, CCEBA's proposal for a stakeholder proceeding, technical conference, or evidentiary hearing to evaluate potential alternatives to the peaker method would not be an efficient use of the Commission's or the parties' resources.

[14] 18 C.F.R. § 292.304(b)(7) ("A state regulatory authority or nonregulated electric utility may use a Competitive Price as a rate for as-available qualifying facility energy sales to electric utilities located outside a market defined in §292.309(e), (f), or (g). A Competitive Price may be either a Market Hub Price or a Combined Cycle price[.]").

[15] 18 C.F.R. § 292.304(a)(1); Joint Initial Statement at 12 n.28 (pointing to peaker method's inclusion in the PURPA Title II Compliance Manual).

B. Portfolio P3 Fall Base from the Companies' CPIRP is the Appropriate Reference Portfolio for Calculating DEC's and DEP's Avoided Costs.

The Commission has long held that a utility's avoided cost rates should be based on its most recently filed integrated resource plan ("IRP").[16] Accordingly, the Companies' updated standard offer avoided cost rates, filed on February 15, 2024, are based on Portfolio P3 Fall Base, which is the reference portfolio identified in the Companies' Supplemental Planning Analysis to their CPIRP. While the Public Staff expressly supports the Companies' use of Portfolio P3 Fall Base, the AGO advocates for the Commission to direct the Companies to recalculate their avoided cost rates using Portfolio P1 Fall Supplemental. In the Companies' view, however, it would be inappropriate to develop avoided costs based on the data in that portfolio for a number of reasons.[17] First, the Companies have not selected Portfolio P1 Fall Supplemental as their CPIRP reference portfolio, and requiring the Companies to develop avoided cost rates based on a portfolio *other than* the Companies' identified IRP reference portfolio would mark an unwarranted departure from longstanding practice in avoided cost dockets.[18] Moreover, as the Companies explained in Chapter 3 (Portfolios), Chapter 4 (Execution Plan), and Chapter

---

[16] *See, e.g.*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 11 (Finding of Fact No. 24), Docket No. E-100 (Apr. 15, 2020) ("Sub 158 Order") (directing utilities to incorporate the first year of need identified in the utility's "most recently filed IRP"); Sub 148 Order at 109 (Ordering Paragraph No. 6) ("DEC, DEP, and Dominion shall, in future avoided cost proceedings propose commodity price forecast methodologies that are consistent with those proposed in the utility's most recently filed IRP."); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 65 (Ordering Paragraph No. 8), Docket No. E-100, Sub 140 (Dec. 17, 2015) (the "Phase I Sub 140 Order") ("[T]he generation expansion plans used in the avoided cost production cost models for the purpose of calculating avoided energy rates shall be based on IRP expansion plans that take into account only known and quantifiable costs.").

[17] The AGO argues that because Portfolio P1 Fall Base is the only portfolio in the Supplemental Planning Analysis that achieves the 30% carbon emissions reduction target (the "Interim Target) by 2030 as targeted in N.C.G.S. § 62-110.9, it would be inappropriate to rely on any other portfolio in developing the Companies' avoided costs. The Companies disagree with the AGO's analysis regarding compliance with the Interim Target but agree with the AGO that this issue is more appropriately addressed in the CPIRP proceeding.

[18] *See* supra n. 16.

NC of their CPIRP, Portfolio P1 Base—and, by extension, Portfolio P1 Fall Supplemental—is unattainable and not the most reasonable, least cost and least risk planning pathway due to the pace, scope and scale of new resource additions that portfolio would require in the near-term. Even assuming *arguendo* that the Companies could reliably execute P1 Base Fall Supplemental, the practical result of accelerating the incremental near-term renewable resource additions by 2030 identified as needed in Portfolio P1 Fall Supplemental would have the effect of decreasing avoided energy rates since must-take PURPA QFs are marginal energy resources that are valued after renewables planned for in an IRP. This expected decrease in the avoided energy rate would unjustly and inaccurately decrease the avoided energy rate for must-take PURPA QFs based on an amount of IRP-selected solar that the Companies do not believe is executable.[19]

The AGO also argues the Commission should direct the Companies, in this proceeding and future avoided cost proceedings, to recalculate their avoided cost calculations within 90 days of the Commission's approval of its CPIRPs "to more closely align the avoided cost proceedings with approved—rather than proposed—CPIRP."[20] As a threshold matter, the Commission has long approved the use of inputs consistent with the utility's most recently filed IRP[21] and has never required utilities to file updated standard offer avoided cost rates following issuance of a final IRP ruling and between biennial proceedings. Doing so now would create administrative inefficiency that is unnecessary given the biennial cadence of avoided cost proceedings. The Commission's final order on the Companies' proposed CPIRP is scheduled to issue on or before December 31, 2024,

---

[19] AGO Comments at 17-19.

[20] *Id.* at 19-20.

[21] *See* supra n. 10.

and the Companies' next biennial avoided cost filing must be submitted to the Commission just ten months later, on or before November 1, 2025. The practical result of an additional compliance filing in late March 2025, as the AGO proposes, would have the Companies making separate filings to update their avoided cost rates and Schedule PP tariffs within seven months of each other. Moreover, the short lag period between approval of a CPIRP and the Companies' next avoided cost filing that the AGO appears to be solving for would only impact small QFs 1 MW or less selling pursuant to the standard offer. The Companies update their large QF avoided cost rates for changes in the preferred resource plan or other material changes on a quarterly basis, meaning that all requests for updated negotiated avoided cost rates starting in the quarter after the Commission issues its CPIRP Order would incorporate any updates from the Commission-approved CPIRP reference portfolio. For all of these reasons, the update proposed by the AGO is unnecessary and represents an inefficient use of the parties' and the Commission's valuable resources.

II. Avoided Energy Rates

A. Implied Carbon Emission Costs That Do Not Actually Avoid Cost for Customers Should Not be Included in Avoided Cost Rates.

In the 2021 Sub 175 Proceeding, the Commission considered—and ultimately rejected—a proposal to include implied carbon emission costs in the Companies' calculated avoided cost rates. The Commission's rationale for rejecting the proposal is equally applicable in this proceeding. While HB 951 imposes a limit on the total CO_2 *emissions* from the Companies' generating units, it does not impose any *direct price* on CO_2 emissions. Because HB 951 does not legislate a direct price or tax on carbon emissions that can be avoided by purchasing energy or capacity from a QF, there is no separate avoidable cost of carbon emissions that purchasing QF power will allow the Companies to avoid.

The Commission has long held 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.[22] The Commission's position on this issue is informed by and consistent with FERC's guidance 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.[23] In its Sub 175 Order, the Commission confirmed that it was "not appropriate to include an implied cost of avoided carbon emissions in DEC's and DEP's avoided cost calculation at this time" because such costs were not "known and verifiable."[24]

In this proceeding, the Public Staff does not recommend any adjustment to the Companies' avoided energy and/or capacity rates to account for a purported cost of carbon.[25] The AGO, on the other hand, suggests that the cost of carbon is now "known and verifiable" because HB 951 imposes a "mass cap" on the amount of CO_2 the Companies' systems can generate in North Carolina. While the AGO "takes no position on the appropriate method to quantify the value of carbon emissions at this time[,]"[26] it

---

[22] Phase I Sub 140 Order, at 8 (Finding of Fact No. 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.").

[23] *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.").

[24] Sub 175 Order at 29.

[25] *See* Public Staff Comments at 50.

[26] AGO Comments at 13.

recommends the Commission establish an avoided cost that "aligns with the costs the Companies would incur to meet statutory carbon reduction mandates in the absence of carbon-free QFs[.]"[27] In so arguing, the AGO suggests that the Companies failed to update their avoided cost methodology to reflect the impact of the Carbon Plan.[28] This is not accurate.

The Companies filed their Joint Initial Statement in the 2021 Sub 175 Proceeding more than six months before filing their initial proposed Carbon Plan with the Commission in May 2022. Accordingly, the Companies' avoided cost rates as approved by the Commission in the Sub 175 Order were based on their respective 2020 IRPs, with certain limited updates, and did *not* incorporate any Carbon Plan portfolio. The Companies' Reply Comments in the 2021 Sub 175 Proceeding explained that their future avoided cost filings would appropriately reflect any avoided cost of carbon by using the Carbon Plan's reference portfolio to calculate avoided costs. Specifically, the Companies noted:

> [T]he 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 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.[29]

[27] *Id.* at 17.

[28] *Id.* at 12.

[29] DEC & DEP Reply Comments at 20-21, Docket No. E-100 Sub 175 (filed Apr. 1, 2022).

The Companies have done just that in this proceeding—calculating their avoided costs using CPIRP Portfolio P3 Fall Base as the appropriate reference portfolio that fully incorporates the system costs of new generation that a QF purchase will allow the Companies to avoid.

Moreover, the mass cap modeling approach used to model the CPIRP does not result in a "known and verifiable" avoidable carbon emissions cost as the AGO contends. As already explained, the North Carolina General Assembly designed HB 951 to drive an orderly reduction in carbon emissions from the Companies' generating fleet through establishment of an at-the-stack emissions reduction framework—and *not* through the establishment of any explicit carbon tax or avoidable cost of carbon to be paid by customers to QFs. In other words, the Legislature could have chosen to assign a cost to carbon emissions, but it did not. The Companies further note that their customers will be disadvantaged if required to pay an avoided cost of carbon to PURPA QFs. This is because HB 951 requires that all environmental and renewable attributes associated with new solar generation selected by the Commission in the CPIRP are conveyed to the utility for the benefit of its customers while the traditional standard PURPA contract does not convey such attributes.[30] Accordingly, compensating QFs for an avoided cost of carbon without requiring the transfer of environmental and renewable attributes to the utility would actually increase costs for customers and not maintain customer indifference between the utility generating or purchasing power and purchasing power from a QF.

The AGO attempts to support its position by likening HB 951 to Virginia's previous participation in the Regional Greenhouse Gas Initiative ("RGGI"), arguing that the

[30] S.L. 2021-165, Part I, Section 1.(2)(b).

Commission previously approved an avoided cost of carbon when it approved DENC's avoided cost rates in the 2021 Sub 175 Proceeding.[31] While it is true that DENC's Commission-approved avoided cost rates in the 2021 Sub 175 Proceeding were developed using a resource plan that incorporated the RGGI's carbon price,[32] this is an apples to oranges comparison. The RGGI sets an explicit price on carbon allowances that utilities from member states can purchase at quarterly auctions and/or buy and sell in secondary markets.[33] HB 951, by contrast, directs the Commission to determine and the Companies to then execute the most reasonable least cost plan to reduce carbon emissions from the generating fleet and to transition to carbon neutrality. There is no separate known and verifiable cost associated with reducing carbon emissions that purchases of non-renewable QF energy and capacity will allow the Companies to avoid.

For all of these reasons, the Companies have already appropriately incorporated the CPIRP into their avoided cost rates and no additional "known and verifiable" cost of carbon exists for incorporation into the Companies' avoided cost rates.

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

The Commission's 2021 Sub 175 Order directed the Companies to conduct a preliminary investigatory study of the operating characteristics of inverter-based resources ("IBRs") at certain of its own IBR facilities "to understand which ancillary services each

---

[31] AGO Comments at 11; *see also* Sub 175 Order at 30 (finding that "the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law and is therefore appropriate to be used in determining DENC's avoided energy rates.").

[32] Notably, Virginia exited RGGI on December 31, 2023 and, accordingly, DENC's proposed avoided cost rates in this proceeding do not reflect any avoided cost of carbon. Public Staff Comments at 10.

[33] *See* The Regional Greenhouse Gas Initiative: About the Regional Greenhouse Gas Initiative, *available at* https://www.rggi.org/sites/default/files/Uploads/Fact%20Sheets/RGGI_101_Factsheet.pdf.

resource or combination of resources can provide."[34] The Commission directed the Companies to file a report on their findings and to "address the potential benefits, if any to customers of providing ancillary services and whether a pilot program would be worthwhile."[35] In compliance with the Commission's directives, the Companies tested the operating characteristics of IBRs at its Elm City and Monroe standalone solar facilities and at its Asheville Rock Hill standalone battery facility and filed a report with their findings on August 1, 2023 (the "IBR Testing Report" or the "Report").[36]

As detailed in the IBR Testing Report, the study showed that it is infeasible for standalone solar to provide measurable ancillary services such as active power regulation on a partly to mostly cloudy day and that, instead, solar facilities *actually increased* the need for ancillary services from conventional resources during cloudy days.[37] The Report further concluded that additional testing with different and larger utility-owned IBR resource types (including standalone batteries and solar plus storage) would be useful to more "thoroughly evaluate the capabilities of IBRs to provide certain ancillary services."[38] The Public Staff generally agrees with the Companies that further research using larger scale batteries would be beneficial to determine whether QFs with energy storage can provide "significant" ancillary services in the future.[39] Although the Companies did not identify a timeline for conducting additional testing in their IBR Testing Report, larger scale batteries would need to be added to the Companies' system before additional testing

---

[34] Sub 175 Order at 45.

[35] *Id.* at 46.

[36] IBR Testing Report, Docket No. E-100, Sub 176 (Aug. 1, 2023).

[37] *Id.* at 17.

[38] *Id.*

[39] Public Staff Comments at 12.

could produce meaningful results. In other words, the Companies anticipate that additional testing and study could take place in 2025 after a battery storage facility of 25 MW has been connected to the DEC system and a battery storage facility of 30 MW has been connected to the DEP system. The Companies additionally propose that further testing of the Companies' IBR resources should be evaluated in the CPIRP proceeding—and not the avoided cost proceeding—as part of the Companies' ongoing planning and execution efforts that must maintain or improve the reliability of their system. The Companies' IBR Testing Report demonstrates that standalone solar facilities are unable to provide net positive ancillary services to the system. As the Public Staff acknowledges, "larger scale batteries, which are not subject to . . . sunlight variations . . . will likely be necessary if QFs are to provide significant ancillary services in the future."[40] In absence of such large-scale batteries on the system, it is not an efficient use of the Commission's or the parties' resources to continue considering ancillary services in each biennial avoided cost proceeding.

In the face of this evidence, CCEBA and NCSEA ask the Commission to require the Companies to perform additional, comprehensive testing now, engaging with stakeholders to design the study.[41] NCSEA additionally recommends that the Companies should launch a pilot program to compensate QFs for providing reactive power management and voltage support. As already stated, the Companies do not believe there is utility in further testing before the Companies are able to interconnect larger scale batteries to the system. As the Companies explained in their 2021 Sub 175 Proceeding

[40] Public Staff Comments at 12.

[41] CCEBA Comments at 7; NCSEA Comments at 20-21.

Reply Comments, FERC has already considered and rejected the idea of compensating QFs for providing reactive power when it established the *pro forma* Large Generator Interconnection Procedures and Large Generator Interconnection Agreement in Order No. 2023 and *required* all generating facilities to provide reactive power within a specified range.[42] FERC explained its determination in a subsequent case, noting 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 compensate non-affiliated (IPP) generators for reactive power service within the deadband."[43] According to FERC:

> [A]n interconnecting generator 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.[44]

The same logic applies here. Because the Companies do not compensate their own fleet generators for reactive power service,[45] it would not be appropriate to provide reactive power compensation to QFs simply for reliably operating in parallel with the Companies' systems.

For the reasons described above, the Companies respectfully request that the Commission consider any further IBR testing as part of the CPIRP docket and reject

[42] *See* Order No. 2003, FERC Stats. & Reg. ¶ 31,146 at P 546 (2003); *see also* Order No. 827 at 29, P 34.

[43] *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 30 (2007).

[44] *Id.* at P 29.

[45] *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.

CCEBA's and NCSEA's request to launch a stakeholder proceeding, comprehensive study, and pilot program in this proceeding. Specific to this and future avoided cost proceedings, the Companies' IBR Testing Report and pilot study demonstrate that uncontrolled, must-take QF injections of power into the Companies systems do not avoid incremental ancillary services costs on the Companies' systems. Accordingly, the Commission should find that QF rates already appropriately compensate QFs for "full" avoided costs and decline to direct further evaluation of this issue in future biennial avoided cost proceedings.[46]

III. Avoided Capacity Rates

A. The Companies Agree to Discuss with the Public Staff in Advance of the Next Biennial Avoided Cost Proceeding the Appropriate Peaking Unit by Which to Calculate the Companies' Avoided Capacity Costs.

As explained in their Joint Initial Statement, the Companies have used an F-Frame CT as the avoided peaking unit in at least the last four avoided cost proceedings.[47] To calculate their avoided capacity rates, the Companies relied on the estimated cost for an F-frame CT included in the publicly available U.S. Energy Information Administration's ("EIA") Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023 ("2023 EIA Report"), which was the most up-to-date EIA Report available at the time the Companies filed their Joint Initial Statement in November 2023. Acknowledging that "[c]ost data on F-frame CTs has been readily available for many years and reliably used by the Utilities to determine avoided capacity payments to QFs[,]"[48] the

[46] AGO Comments at 2-3, 12-13, 15.

[47] Sub 175 Order at 14.

[48] Public Staff Comments at 13.

Public Staff supports the Companies' and DENC's continued use of an F-frame CT as the peaking unit in this proceeding.[49]

In January 2024, the EIA published its 2024 EIA Report, which included generic cost estimates for H-class CTs, but not F-frame CTs. Noting this departure from EIA's historical practice of providing F-frame CT cost estimates, the Public Staff recommends the Companies and DENC use an advanced class CT to calculate their avoided capacity rates in the next biennial avoided cost proceeding "if no other publicly available cost data exists."[50] Like the Public Staff, the Companies agree it is appropriate to use publicly available cost data, and they commit to engage with the Public Staff in advance of the next biennial proceeding to consider the appropriate peaking unit for use in developing their avoided capacity costs, including whether an offset calculated through the "net peaker" method is warranted.[51]

The AGO, on the other hand, takes issue with the Companies' use of an F-frame unit in *this* proceeding. According to the AGO, the F-frame CT is no longer "valid" as a peaking resource because the Companies do not include F-frame CTs as a selectable resource in developing the Companies' proposed CPIRP.[52] The AGO is correct to note that the CPIRP plans for the addition of H-class CT units to the Companies' system. However, the Companies' calculation of avoided costs using the F-frame turbine under the peaker method continues to establish a reasonable proxy of the avoidable cost of capacity on the

[49] *Id.* at 13-14.

[50] *Id.* at 14.

[51] *See* Public Staff Comments at 14 (recommending that utilities use the "net peaker" method to calculate avoided capacity payments in the next biennial avoided cost proceeding, incorporating the cost of advanced CTs with an "offset to the cost of the unit based upon the energy value associated with an advance CT").

[52] AGO Comments at 15.

system today as well as future planned capacity resources expected to be online during the term of the contract.

As background, 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.[53] 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 represents a valid estimate of the utility's avoided costs. From an installed cost perspective, simple cycle F-frame peaking units and H-class peaking units are generally similarly priced and 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.

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

[53] *Order Setting Avoided Cost Input Parameters,* Docket No. E-100, Sub 140, at 9 (Finding of Fact No. 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.").

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 this docket. As the Public Staff notes, while advanced class CTs are likely to replace F-frame CTs in the future, F-frame CTs are still widely used for power generation, including on the Companies' systems. Accordingly, the Commission should approve the Companies' continued use of an F-frame CT as the avoided peaking unit in this proceeding and the Companies commit to further discuss this issue with Public Staff in advance of the next biennial proceeding.

B. The Companies' Avoided Capacity Rates Reflect the Appropriate Capacity Value and Rate Design Applicable to Solar QFs.

CCEBA raises concern that the Companies' avoided cost rates do not assign capacity value or otherwise provide for capacity payments to new solar and makes several attempts to argue that solar QFs should be compensated for avoided capacity.[54]

First, CCEBA argues that the Companies' Effective Load Carrying Capability ("ELCC") Study[55] fails to properly account for the capacity value of solar related to its synergistic effect with storage resources, including battery storage and pumped storage hydro.[56] This argument fundamentally misunderstands the Companies' standardized approach to calculating avoided capacity rates. As explained in their Joint Initial Statement, the Companies have long used the loss of load risk identified in their most recent resource adequacy study as the basis for their seasonal and hourly allocations of capacity payments.

---

[54] CCEBA Comments at 7.

[55] Verified Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas LLC and Duke Energy Progress LLC, Attachment II, Docket No. E-100, Sub 190 (filed Aug. 17, 2023) ("CPIRP Attachment II").

[56] *Id.* at 7.

This approach was part of the Commission-approved rate design stipulation between the Companies and the Public Staff in the 2018 Sub 158 Proceeding, and the Companies used the loss of load risk identified in the 2023 Resource Adequacy Study[57] to update the avoided capacity rate design in this proceeding. Importantly, solar ELCC values do not play a role in setting the seasonal and/or hourly capacity allocation nor are the specific attributes of solar (or solar paired with any other resource) used in the calculation of avoided capacity rates. Because avoided cost rates are generic rates applicable to all QFs and derived based on the system's capacity need, a QF's specific attributes do not impact the Companies' avoided cost rates (except indirectly to the extent those attributes or characteristics enable/limit the QFs' ability to deliver energy during peak periods when DEC or DEP has an avoidable capacity need). Thus, solar ELCC values simply do not play a role in the Companies' avoided cost rate calculations.[58]

Second, CCEBA argues that the Companies "do[] not appear to provide capacity payments for existing QFs . . . that execute new PPAs following the expiration of their existing PPAs." [59] This position is both not correct and directly conflicts with the Companies' longstanding approach to resource planning, which assumes a capacity reduction—and *not* automatic renewal—upon expiration of a QF's PPA. More specifically, the Companies have historically (1) recognized that a QF's commitment to

[57] The 2023 Resource Adequacy Study was prepared by Astrapé Consulting and filed as Attachment I to the Companies' CPIRP in Docket No. E-100, Sub 190.

[58] In any event, the Companies' ELCC study appropriately considered the purported synergistic benefits of (1) solar and battery storage; and (2) solar and pumped storage. *See* CPIRP Attachment II (2023 ELCC Study) at 4-6. The Companies' standardized rate design methodology is discussed in depth on pages 8-10 of Exhibit 8 to the JIS.

[59] CCEBA Comments at 9.

provide capacity extends only for the duration or "specified term"[60] of its PPA; and (2) treated all existing and newly constructed QFs similarly, such that existing QFs do not receive preferential treatment over new QFs.[61] In the 2018 Sub 158 Proceeding, the Commission considered this issue in the context of expiring hydro QFs PPAs and agreed with the Companies' approach, finding that "it would be imprudent resource planning to assume that QFs are obligating themselves to deliver capacity and energy past the end of their contract term."[62] The Commission further held that "it would be discriminatory between QFs to assume that a pre-existing QF has a priority right to enter into a new contract to sell and deliver capacity over a new term versus the rights of any other QF to commit itself to avoid the utility's capacity need."[63] Similarly here, it would be "imprudent resource planning" for the Companies to assume expiring solar QFs will certainly renew their expiring PPAs and it would be "discriminatory between QFs" to give a legacy solar QF "a priority right" over a new QF. Because the Commission has already considered and rejected CCEBA's arguments on this point, it would be inappropriate for the Companies to continue providing capacity payments to QFs with an expiring PPA in the absence of a demonstrated capacity need.

C. The Companies' Proposed Performance Adjustment Factor ("PAF") Capacity Multiplier Should be Approved.

As explained in their Joint Initial Statement, the Companies are proposing to discontinue the outdated 2.0 PAF for run-of-river hydro QFs. Instead, DEC and DEP are proposing standard offer avoided cost rates for run-of-river hydro QFs that are equivalent

---

[60] 18 C.F.R. § 292.304(d)(1)(ii).

[61] *See* 2018 Sub 158 Proceeding G. Snider Rebuttal Testimony at 10-11.

[62] Sub 158 Order at 51-52.

[63] *Id.* at 51.

to other QFs and reflect the same standard PAF of 1.05 for DEC and 1.07 for DEP rather than the elevated and outdated 2.0 PAF.[64] These changes appropriately reflect both (1) legislative amendments to the State's PURPA implementation in Session Law 2017-192 and Session Law 2019-329 which no longer designate hydroelectric generators as unique small power producers; and (2) the expiration of the Sub 140 Hydro Stipulation.[65] The Commission has already approved standardizing the PAF adder for run-of-river hydro QFs that are in excess of 1 MW and subject to bilaterally negotiated PPAs with the PAFs paid to the other renewable resource generators.[66] The Public Staff supports the Companies' proposal, noting that discontinuation of the 2.0 PAF will "preserve fairness" across all QFs and to Duke's customers that pay for QF power, and no other party objects to the proposal. Accordingly, the Companies request that the Commission approve the Companies' proposal to discontinue this legacy, inflated capacity multiplier to promote fairness across all QFs.

Separate from the 2.0 PAF, the Public Staff and CCEBA make limited additional recommendations applicable to DEC's and DEP's standard PAFs. The Public Staff recommends that the Companies should begin utilizing solar outage data to calculate their PAF in the next avoided cost proceeding.[67] As background, the North American Electric Reliability Corporation ("NERC") has designed a phased approach for reporting solar data in the Generating Availability Data System ("GADS") database, whereby solar plants with

---

[64] Joint Initial Statement at 21.

[65] *Id.* at 19-20.

[66] *Order Denying Motion to Dismiss and Denying Requested Relief* at 8, Docket No. E-7, Sub 1254 (Apr. 18, 2022) ("The Sub 158 Order clearly established that the 2.0 PAF would cease to be applicable after December 31, 2020, and therefore Northbrook was ineligible for a 2.0 PAF when DEC calculated its avoided cost rates on January 29, 2021.").

[67] Public Staff Comments at 6.

a total installed capacity of 100 MW or more are to begin mandatory reporting by January 1, 2024, and solar plants with a total installed capacity of 20 MW or more are to begin mandatory reporting by January 1, 2025.[68] As of the date of this filing, although the Companies do not own any utility-owned solar facilities with a total installed capacity of 100 MW or more, they plan to implement a pilot reporting program sometime in 2024 to test GADS reporting for some facilities and will plan to include solar outage data in determination of the PAF as the data becomes available. However, the Companies will be unable to incorporate solar outage data in the 2025 avoided cost filing, as by November 2025, the Companies will have gathered very limited solar outage data and historically, the PAF is calculated based on data from the past five calendar years. Nonetheless, the Companies recognize the importance of incorporating solar outage data into the PAF and are amenable to discussing the same with the Public Staff in advance of future biennial avoided cost filings.

Finally, CCEBA argues that the Companies should incorporate its experience in the outages during Winter Storm Elliot in December 2022, which impacted gas supply and CT performance, into its PAF analysis.[69] The Companies have already implemented this recommendation by including outage data for 2022, including data related to Winter Storm Elliot, in the historic dataset used to calculate the PAF.

[68] North American Electric Reliability Corporation, GADS Solar Data Reporting Instructions, https://www.nerc.com/pa/RAPA/gads/Pages/GADS-Solar-DRI.aspx.

[69] CCEBA Initial Comments at 9-10.

IV. **<u>The Companies Agree to Report on QFs Attempting to Avoid the Companies' Respective Solar Integration Services Charge ("SISC") As Recommended by the Public Staff</u>**

As a threshold matter, the Public Staff supports and no other party challenges the Companies' updated SISC as supported by the Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge Study prepared by Astrapé Consulting.[70] In the absence of any objection to the updated SISC, it is ripe for Commission approval.

In its Initial Comments, the Public Staff recommends that the Commission direct the Companies to (1) in future avoided cost filings, "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," and (2), "address QFs seeking SISC avoided in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of SISC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC."[71] The Companies note that the Commission's Sub 175 Order already requires the Companies to address both of the Public Staff's recommendations.[72] As noted in the Companies' Joint Initial Statement, to date, no QF has contracted to sell QF power as a controlled solar generator to avoid the SISC.[73] The Companies do not object to complying with these reporting and filing obligations in the future as recommended by the Public Staff.

---

[70] Joint Initial Statement at 29; Public Staff Initial Comments at 41.

[71] Public Staff Comments at 52.

[72] Sub 175 Order at 71 (Ordering Paragraph 16).

[73] Joint Initial Statement at 30.

V. Energy Storage Retrofit Rates

In their Joint Initial Statement, the Companies explained that since the Commission approved their Energy Storage System Retrofit ("ESS Retrofit") Rates in the Sub 175 Order, no QF had submitted a Notice of Commitment Form ("NOC Form") or otherwise elected to participate in the ESS Retrofit program. Consistent with the Companies' September 29, 2021 ESS Retrofit Compliance Filing (the "Compliance Filing") and the Commission's May 12, 2022 Order Granting Waivers to Implement Energy Storage System Expedited Study Processes and Approving Process to Establish Eligibility of avoided Cost Rates for Retrofit Energy Storage Systems (the "ESS Retrofit Order"), the Companies' predetermined ESS Retrofit Rates expired on November 1, 2023. Although the Companies are not proposing to renew the predetermined ESS Retrofit Rates in this proceeding, QFs that submit their Notice of Commitment Forms after November 1, 2023, will be eligible for a negotiated rate calculated at the time the Notice of Commitment Form is submitted based on the most recent Commission-approved avoided cost methodology, consistent with N.C.G.S. § 62-156(c). The Public Staff, for its part, agrees with the Companies' proposal to discontinue the predetermined rates, noting the "lack of interest by QFs and the adoption of cluster studies under queue reform [such that] [a]ny QF wishing to add battery storage to an existing facility can submit an interconnection request to one of the Companies' annual Definitive Interconnection System Impact Study Clusters."[74]

NCSEA and CCEBA, however, advocate that the Companies should propose a new predetermined ESS Retrofit Rate in the 2025 biennial avoided cost proceeding. NCSEA argues primarily that the ESS Retrofit Framework approved by the Commission in 2022

[74] Public Staff Comments at 12.

did not appropriately incentivize QFs to add energy storage to their existing facilities. According to NCSEA, because the ESS Retrofit Rates were structured to be offered only for the *remainder* of a PPA's term, very few QFs were eligible to receive the "most lucrative" 10-year ESS Retrofit Rates and the rates for shorter terms "were insufficient for a QF to justify the short payment period for its investment in an ESS."[75] Accordingly, NCSEA proposes that ESS Retrofit Rates should be available only to QFs that are renewing their PPA term, making them eligible to receive a 10-year ESS Retrofit Rate.[76]

Importantly, NCSEA's proposal (which CCEBA supports) would require the Companies to pay "renewing" QFs that elect to add energy storage at rates *above* the Companies' avoided costs and for future contract terms that do not align with North Carolina law limiting negotiated QF PPAs to rates established for "a fixed five-year term."[77] In its Sub 175 Order, the Commission approved the Public Staff's bifurcated rate proposal, which required QFs to separately meter energy output from their original facility and new battery storage system. Under this bifurcated rate design, energy from an existing facility was to be compensated pursuant to the rate set forth in the original PPA, while energy from any energy storage system was to be compensated at then-current avoided cost rates. Importantly, however, these rates were available only for the remaining term of the QF's existing PPA entered into prior to enactment of HB 589's revisions to the State's PURPA implementation framework. In proposing that the Companies should develop new, predetermined ESS Retrofit Rates which will become available only upon the expiration of an existing PPA, NCSEA is implicitly suggesting that the Companies should

---

[75] NCSEA Comments at 9.

[76] *Id.*

[77] N.C.G.S. § 62-156(c)

pay these existing facilities for a new PPA term at avoided costs fixed for longer than five years, presumably to incentivize the addition of energy storage. In support of this argument, NCSEA cites to Subsection 7 of the Companies' proposed Terms and Conditions, which provides that a PPA can be renewed for a subsequent term at a rate that is "mutually agreed upon by the parties negotiating in good faith and taking into consideration the Company's then avoided cost rates and other relevant factors[.]"

As a threshold matter, the "must purchase" obligation under PURPA requires utilities to offer to purchase QF power at just and reasonable rates that "make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.[78] Accordingly, at the expiration of the contract term, the existing facility, with or without new energy storage, would be eligible for the Companies' avoided cost rates available at that time and there is no need to develop any separate, special ESS Retrofit Rates. The Companies continue to believe that the most appropriate course is to offer negotiated rates to QFs electing to add storage to their existing facility at the expiry of their current PPA term consistent with North Carolina law implementing PURPA.

VI. <u>Net Excess Energy Credit ("NEEC")</u>

SACE asks the Commission to reconsider several issues that were recently determined as part of the Commission's March 23, 2023 *Order Revising Net Metering Tariff* (the "NEM Order") issued in Docket No. E-100, Sub 180 and August 2, 2023 *Order Establishing Net Excess Energy Credit for NEM Tariff* (the "NEEC Order") issued in Docket No. E-100, Sub 175. Specifically, SACE argues that the Commission should require the Companies to (1) use a 10-year avoided cost time horizon to calculate the

[78] Sub 175 Order at 1-2.

annualized NEEC—a position the Commission rejected when it approved calculation based on a 5-year time horizon in its August 2023 NEEC Order; and (2) incorporate avoided transmission and distribution ("T&D") costs in its calculation of the NEEC—a position the Commission rejected in its March 2023 NEM Order. As the Companies explain below, the rationale supporting the Commission's initial determinations on these two issues has not changed in the six (6) months to a year since the Commission last considered them.

With respect to the calculation term, the Companies' initially-proposed NEEC rates in the 2021 Sub 175 Proceeding were based on a 2-year avoided cost calculation term.[79] The Companies believed the 2-year calculation term to be the most appropriate time horizon for calculating the NEEC because net energy metering ("NEM") facilities do not enter into long-term contractual relationships with the Companies and, consequently, the rates they receive are updated every two years. In response to intervenor comments advocating for a 10-year calculation term, the Public Staff noted that such a term may be too long in the absence of a contractual relationship committing to sell to DEC or DEP and instead proposed a 5-year calculation term.[80] The Companies thereafter agreed to the 5-year time horizon in a good faith attempt to compromise and reach consensus, and the Commission ultimately approved the Companies' NEEC calculation methodology. Just over six months since the Commission issued its final determination on this issue, SACE now seeks to reconsider this issue.

---

[79] *See* Joint Initial Statement, Exhibit 11, Docket No. E-100, Sub 175 (Nov. 1, 2021).

[80] *See* NEEC Order at 2-3.

Consistent with their position in the 2021 Sub 175 Proceeding, the Companies continue to believe it would be inappropriate and potentially risk a cross-subsidization from non-participating customers to calculate the NEEC based on a 10-year avoided cost time horizon. In establishing NEM rates, the Commission recognized that such rates, by law, should be "nondiscriminatory" and that "cross-subsidization should be avoided by holding harmless electric public utilities' customers that do not participate" in NEM programs.[81] In essence, utilizing a 10-year calculation term would incorporate longer-term forecasts and introduce increased risk of inaccurate pricing signals to NEM customers and over-payments for QF power. For example, the Companies avoided energy pricing is based upon forecasted natural gas pricing using five years of market prices followed by three years of blending before transitioning to fundamental forecasts in years nine (9) and ten (10). Because fundamental forecasts used in later years tend to be higher than current market prices, calculating the NEEC based on a 10-year time horizon unnecessarily risks overpayment to NEM participants based on the gas forecast. Unlike Standard Offer QFs that commit to sell all of their energy output to the Companies for a specified term in exchange for a 10-year fixed rate, NEM facilities are compensated through the NEEC, which is updated every two years in the biennial avoided cost proceeding. Because the NEEC is updated regularly, NEM participants receive a rate that more accurately reflects the Companies' actual avoided costs. In contrast, further extending the forecast period for such rates beyond the current five-year time horizon increases risk of forecasting rates that will exceed the utility's avoided cost, with which the Commission has signaled the NEEC

[81] *See Order Approving Revised Net Metering Tariffs* at 4, Docket No. E-100, Sub 180 (March 23, 2023) citing N.C.G.S. § 62-126.2; 62-126.4.

should align.[82] The Comments of Justin Barnes submitted as Attachment 4 to SACE's comments also suggest that the Companies' CPIRP modeling assumes continued operation of customer-sited solar through 2050 and, as a practical matter, rooftop solar facilities "regardless of the whether it is subject to a contractual obligation, can reasonably be expected to operate for at least 20 years." Specific to CPIRP modeling, the Companies do assume energy from rooftop solar facilities, in the aggregate, increases over time but—recognizing that the CPIRP is a generic modeling exercise—do not make explicit assumptions that third-party owned facilities will operate for any specified term absent a contractual obligation to do so. Moreover, the fact that that a rooftop solar facility is designed to operate for a time horizon longer than five years does not support extending the time horizon for calculating the NEEC, which will be updated every two years. Absent a contractual obligation, there is no certainty that a specific rooftop solar customer will continue to deliver power for any specified term (e.g., the solar facility may already be nearing the end of its useful life, it may become damaged or inoperable, or the homeowner may move and a new owner may elect not to continue to operate the rooftop solar array) or that a NEM customer will actually deliver any power to the system versus fully consuming its self-generation on-site. Finally, to the extent any current NEM customer wishes to sell power as a QF and to obligate itself to deliver capacity and energy for a term of 10-years, Schedule PP remains available as an option.

In its initial comments, SACE also argues that transmission and distribution avoided costs (or benefits) should be included in the NEEC value provided to customers.

[82] *See Order Approving Revised Net Metering Tariffs* at 38-39, Docket No. E-100, Sub 180 (March 23, 2023) ("Commission concludes that it is appropriate for the NEM tariffs to provide that net excess energy exported to the grid by a NEM customer be credited to the customer at the Commission's approved avoided cost rates used for purposes of PURPA").

Importantly, the NEEC stands for "Net Excess Energy Credit" and refers to net energy exported to the grid in excess of the self-generated energy that is consumed by the customer. Additionally, NEEC credits the participating customer for *excess* export energy, thus excluding energy exported to the grid that is offset by later consumption by the customer. In short, a customer who constructs a solar facility to generate the same amount of energy that they anticipate consuming would expect relatively little if any net export energy, at least in most months of the year. The Companies note that the retail rate charged to the customer includes distribution and transmission fixed cost recovery, thus the customer who pays a lower bill as a result of self-consuming energy from the solar system (or exporting generated energy and offsetting imports at a different time) are actually receiving some benefits associated with avoided distribution and transmission costs already. By reducing their costs associated with the core tariff charges, such distribution and transmission costs are being reduced by the solar system owner.

In contrast, SACE proposes to include distribution and transmission value for net export energy, which is random and unpredictable, thus resulting in no such avoidable distribution and transmission planning benefits. For example, suppose a customer installed a solar facility that generated 1,100 kWh in a given month, and the customer's consumption was 1,000 kWh in the same month. The customer would receive the distribution and transmission value associated with the 1,000 kWh, assuming it was never exported to the grid but rather directly self-consumed, by virtue of the fact that their core bills would go down, and those charges include fixed cost recovery for T&D assets. However, the 100 kWh constituting the net exports could come from excess generation at any time across that month. Therefore, the net exports should receive only the avoided energy costs presently included in the Companies' avoided costs calculations—such unpredictable deliveries of energy (in terms of quantity and timing) are insufficient to create any planning or investment benefits in terms of transmission and distribution assets.

SACE fails to distinguish between the core system generation and net exports, merely arguing that solar generation facilities help reduce transmission and distribution investments. Such an argument falls short of the point—NEM customers are *already* receiving a benefit for T&D investment reduction through a reduction in the base tariff charges for self-consumed energy. Calculating the incremental benefit from net excess generation is an entirely different issue which SACE completely fails to acknowledge or address. Importantly, net exports for a customer can be meaningful in some months (e.g. April), but zero in other months (e.g., August or February) when consumption is relatively higher compared to solar generation. SACE fails to meaningfully address the issues around T&D investments benefits in only a few months (typically low-load shoulder months) with no benefits during high-load months when considering applying T&D value to net export energy.

Additionally, AGO incorrectly argues that an incremental carbon benefit should be added to the NEEC as it is not presently being passed to solar customers. While it is true that solar resources have zero carbon emissions when generating electricity, the energy not generated from other facilities is not directly attributable to the solar resources and therefore cannot be included in the NEEC. Additionally, from a Cost of Service ("COS") perspective, carbon emissions have no cost (as no state or federal financial benefits are presently created associated with carbon reduction and therefore COS is not impacted).

Thus, COS analysis that governs utility rate-making has no means by which to flow such supposed benefits to owners of solar facilities.

CONCLUSION

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

1. The Companies' respective updated Schedule PP avoided cost rates, as presented in DEC Updated Exhibit 1 and DEP Updated Exhibit 1 to the Companies' Joint Initial Statement;
2. The Companies' respective Standard Offer Power Purchase Agreement, Terms and Conditions, and Notice of Commitment Form, as presented in their Joint Initial Statement;
3. The Companies' Large QF Notice of Commitment as presented in their Joint Initial Statement;
4. The Companies' NEEC Rates as presented in DEC Updated Exhibit 11 and DEP Updated Exhibit 11 to the Joint Initial Statement; and
5. Any further relief the Commission deems to be just and reasonable and in the public interest.

Respectfully submitted, this the 27th day of March, 2024.

<u>/s/ E. Brett Breitschwerdt</u>

Hayes Finley
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551 / NCRH 20
Raleigh, North Carolina 27602
Telephone: (919) 546-2089
Hayes.Finley@duke-energy.com

E. Brett Breitschwerdt
Tracy S. DeMarco
Ami P. Patel
McGuireWoods LLP
501 Fayetteville Street, Suite 500
PO Box 27507 (27611)
Raleigh, North Carolina 27601
EBB Telephone: (919) 755-6563
TSD Telephone: (919) 755-6682
APP Telephone: (919) 546-6733
bbreitschwerdt@mcguirewoods.com
tdemarco@mcguirewoods.com
apatel@mcguirewoods.com

Counsel for Duke Energy Carolinas, LLC
and Duke Energy Progress, LLC

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Reply Comments, in Docket No. E-100, Sub 194, has been served electronically to all parties of record.

This the 27th day of March, 2024.

/s/ E. Brett Breitschwerdt

E. Brett Breitschwerdt
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601
Telephone: (919) 755-6563
bbreitschwerdt@mcguirewoods.com

Attorney for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC