STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
DOCKET NO. E-100, SUB 194

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, Sub 194	)	
	)	
In the Matter of:	)	COMMENTS OF
Biennial Determination of Avoided	)	THE ATTORNEY GENERAL'S
Cost Rates for Electric Utility	)	OFFICE
Purchases from Qualifying Facilities	)	
– 2023	)	

The North Carolina Attorney General's Office (AGO) respectfully submits these initial comments regarding the proposed avoided costs rates to be paid by the state's electric public utilities for purchases from qualifying facilities. These comments are limited to addressing the proposed avoided cost rates of Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP, together with DEC, the Companies), and "the cost of carbon and the approved Carbon Plan"—one of the topics identified by the Commission in its most recent avoided cost order.[1]

I. INTRODUCTION

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), codified as 18 U.S.C. § 823a-3, and the Federal Energy Regulatory Commission's (FERC) implementing regulations, require electric utilities to (1) purchase power from qualifying facilities (QFs), (2) sell electricity to QFs, and (3) to interconnect

[1] *Order Establishing Standard Rates and Contract Terms for qualifying Facilities*, Docket No. E-100, Sub 175 (Nov. 22, 2022) (Sub 175 Order) at 30.

QFs.[2] QFs are independent, non-utility-owned generators subject to certain eligibility requirements spelled out below. PURPA was enacted, in part, because Congress recognized "the reluctance of traditional electric utilities to purchase power from and sell power to non-traditional facilities."[3] Under PURPA's cooperative federalism framework, states are primarily responsible for implementing Section 210, including determining the appropriate avoided costs rates to be paid by electric public utilities for purchases from QFs. North Carolina's PURPA implementation framework delegates to the North Carolina Utilities Commission (Commission) the responsibility to conduct a biennial proceeding to determine these avoided cost rates as well as the terms and conditions under which those rates must be offered.[4] The Commission issued an order on August 7, 2023, initiating the current biennial proceeding. The Commission's order required all public utilities operating in the state to file proposed rates for purchases from QFs and proposed standard contracts by November 1, 2023, and the Companies complied.

One of PURPA's key aims was to encourage the development of non-utility-owned generation.[5] Accordingly, PURPA's mandatory purchase obligation requires each electric utility to offer to purchase electricity from cogeneration and generation facilities that obtain QF status.[6] In order to qualify as a QF a facility must either: (1) use an alternative energy source (i.e. renewable energy) and have

[2] 18 C.F.R. § 292.303; 16 U.S.C. § 824a-3(a)(2), (b).
[3] *Independent Energy Producers Ass'n v. California Pub. Utils. Comm'n*, 36 F.3d 848, 850 (9th Cir. 1994).
[4] N.C.G.S. § 62-156(b).
[5] *See F.E.R.C. v. Mississippi*, 456 U.S. 742, 742, 102 S.Ct. 2126, 2129 (1982).
[6] *See* 16 U.S.C. § 824a-3(b).

a production capacity of less than 80 MW, or (2) produce both electricity and some other form of useful energy to be "used for industrial, commercial, heating, or cooling purposes."[7] N.C.G.S. § 62-156(b) further limits availability of 10-year standard contracts based on avoided cost rates to facilities with a capacity of less than 1,000 kW.[8] Rates for all other QFs are established via negotiated contracts, which must be consistent with the Commission's approved avoided cost methodology for five years.[9]

FERC promulgates rules to ensure that rates authorized by the states meet PURPA's requirements. These rates are required to be "just and reasonable to the electric consumers of the electric utility and in the public interest," and must not "discriminate against qualifying cogenerators or qualifying small power producers."[10] However, rates may not exceed the purchasing utility's "incremental cost . . . of alternative electric energy."[11] These "incremental cost[s]," also known as "avoided costs," are "the cost to the electric utility of the electric energy which, *but for* the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[12] In order to effectuate these provisions, FERC has stated the rates paid to QFs should be "at, but not above, the statutorily defined incremental or avoided cost of alternative energy."[13] FERC

[7] 16 U.S.C. § 796(17)-(18).
[8] This threshold will be further reduced to 100 kW once an electric utility has entered into power purchase agreements with an aggregate capacity of 100 MW. N.C.G.S. § 62-156.
[9] N.C.G.S. § 62-156(c).
[10] 16 U.S.C. § 824a-3(b)(1)-(2).
[11] 16 U.S.C. § 824a-3(b).
[12] 16 U.S.C. § 824a-3(d) (emphasis added).
[13] Order No. 872, *Qualifying Facility Rates and Requirements: Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 172 F.E.R.C. ¶ 61,041, 61,056, 85 Fed. Reg. 54,638 (July 16, 2020) (Order 872). *See also Order Setting Avoided Cost Input Parameters*,

has continued to reiterate that rates paid to QFs must represent the electric utilities' "full avoided costs," in order to provide "maximum incentive for the development of cogeneration and small power production."[14]

Avoided cost rates are comprised of energy and capacity rates.[15] Energy rates are meant to reflect "the variable costs of producing energy, such as the cost of fuel and variable operations and maintenance," whereas capacity rates "reflect fixed costs, including the financing costs of facilities[.]"[16] Capacity rates are only required to be paid to QFs in the first year where there is an identified avoidable capacity need.[17]

PURPA offers QFs two main avenues for selling electricity to an electric utility. First, a QF can choose to sell its power pursuant to a Legally Enforceable Obligation (LEO) with a price fixed over a period of time (often referred to as the "fixed" rate). Second, a QF can choose to sell its power at the moment of delivery (often referred to as the "as-available" rate).[18] FERC Order 872 updated this paradigm by allowing, but not requiring, states to have energy rates that are only

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Docket No. E-100, Sub 140 at 20 (Sub 140 Order on Inputs) ("[T]he goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF.").

[14] Order 872 at ¶ 61,119 (quoting *Amer. Paper Inst., Inc. v. Amer. Elec. Power Serv. Co.*, 461 U.S. 402, 417-18, 103 S.Ct. 1921, 1930 (1983)).

[15] In its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, E-100, Sub 158 at 90 n. 4 (Apr. 20, 2020), the Commission left open the question of whether there are additional categories of costs that may be included in avoided cost rates, stating "[t]he Commission is not prepared to categorically agree that FERC's regulations prohibit the approval of any rate or charge other than those offered for energy and capacity."

[16] Order 872 at ¶ 61,078. *See also Solar Energy Industries Ass'n v. F.E.R.C.*, 80 F.4th 956, 973 (9th Cir. 2023) (stating that capacity rates are meant to compensate QFs based on the fact that the QFs "existence spares the utility certain fixed costs, such as the cost of building and financing generating plants of its own.")

[17] N.C.G.S. § 62-156(b)(3).

[18] 18 C.F.R. § 292.304(d)(1).

"as-available."[19] The Companies have elected not to utilize this new provision in this proceeding.[20]

On April 15, 2020, the Commission issued an Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 158, which identified a number of issues for parties to address in future proceedings. On October 30, 2020, the Commission granted a continuance of the 2020 avoided cost filing, instead allowing "streamlined" filing and delaying until November 2021 the more comprehensive filings that would address the Sub 158 issues.[21] Most recently, on November 22, 2022, the Commission issued an Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket. E-100, Sub 175.

The Companies' proposed avoided cost rates in this docket reflect a reversal of a recent trend of declining avoided cost rates. As shown in Tables 1, 2, and 3 below, this decline in avoided costs rates has led to fewer QFs—both in number and capacity—being built in North Carolina.[22] While in 2015 North Carolina led the nation in installed PURPA QF capacity,[23] this predominance is no longer the case.

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[19] 18 C.F.R. § 292.304(d)(2).
[20] Joint Initial Statement at 33.
[21] *Order Granting Continuance and Establishing Reporting Requirements*, Docket No. E-100, Sub 167 (Oct. 30, 2020).
[22] Created from data from Companies Response to Public Staff Data Requests 4-5 and 4-6.
[23] *North Carolina has more PURPA-qualifying solar facilities than any other state*, U.S. Energy Information Administration (Aug. 23, 2016), https://www.eia.gov/todayinenergy/detail.php?id=27632.

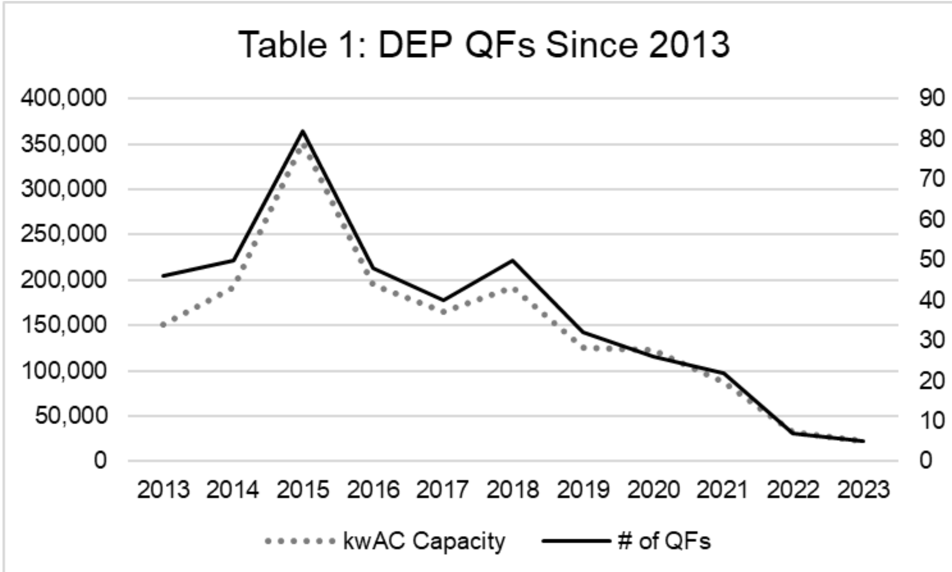
Table 1: DEP QFs Since 2013
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
90
80
70
60
50
40
30
20
10
0
2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023
kwAC Capacity
# of QFs

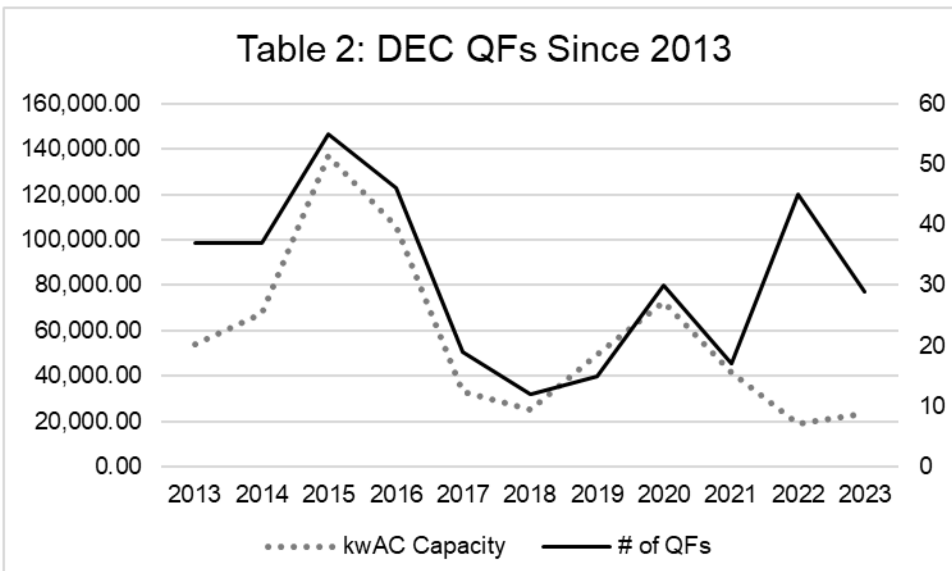
Table 2: DEC QFs Since 2013
160,000.00
140,000.00
120,000.00
100,000.00
80,000.00
60,000.00
40,000.00
20,000.00
0.00
60
50
40
30
20
10
0
2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023
kwAC Capacity
# of QFs

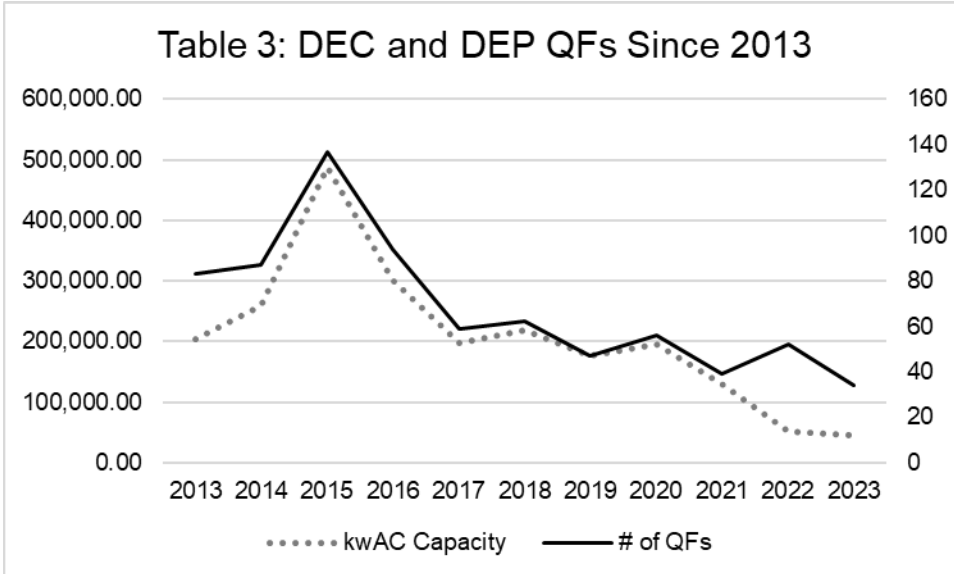

Table 3: DEC and DEP QFs Since 2013

There have been several crucial developments since the Commission's last comprehensive avoided cost proceeding. First, on October 13, 2021, House Bill 951, S.L. 2021-165, was signed by Governor Cooper. Section I of House Bill 951, codified as N.C.G.S. § 62-110.9, required the Commission to adopt a plan to achieve 70% reduction in carbon dioxide emissions from electric generating facilities from a 2005 baseline by 2030 and carbon neutrality by 2050. The Commission adopted its initial Carbon Plan on December 30, 2022. Second, on March 23, 2023, the Commission approved revised net metering tariffs for residential customers.[24] Finally, in orders issued on August 18, 2023 and December 15, 2023, the Commission approved revisions to DEP and DEC's respective non-residential net metering tariffs as part of their general rate cases.[25] Each of the Companies' revised residential and non-residential net metering rates

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[24] *Order Approving Revised Net Metering Tariffs*, Docket No. E-100, Sub 180 (Mar. 23, 2023).

[25] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice*, Docket No. E-2, Sub 1300 (Aug. 18, 2023); *Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions*, Docket Nos. E-7, Sub 1134, E-7, Sub 1276 (Dec. 15, 2023).

include Net Excess Energy Credits (NEEC), which are the amount that customers enrolled in the Companies' net metering tariffs are entitled to receive for energy exported to the grid. The Commission required the Companies to update their NEEC calculation in this proceeding.[26]

II. THE COMMISSION SHOULD ENSURE THAT THE VALUE OF CARBON EMISSION REDUCTIONS ARE INCLUDED IN AVOIDED COST RATES FOR CARBON FREE QFS AND DIRECT PARTIES TO DEVELOP A METHOD TO DERIVE THEIR VALUE.

The Companies' proposed avoided cost rates do not reflect the value of carbon emissions reductions of many QFs and thus fail to fully reflect the Companies' avoided costs as required by PURPA.[27] The Companies have long used, with the Commission's approval, the "peaker methodology" to calculate avoided costs in North Carolina.[28] The Companies have proposed to continue this approach in the current proceeding. Under the peaker methodology, avoided capacity costs are set "at the lowest-cost capacity option available to the utility."[29] For the Companies, this is the cost of a greenfield, F-class combustion turbine (CT) natural gas generator with a decrement meant to reflect the economies of scale associated with a four-unit site.[30] These costs represent the fixed capital, financing, and fixed operating costs for the construction and operation of such a CT. Avoided

[26] *Order Approving Revised Net Metering Tariffs*, Docket No. E-100, Sub 180 (Mar. 23, 2023); *Order Establishing Net Excess Energy Credit for NEM Tariff*, Docket No. E-100, Sub 175 (Aug. 3, 2023).
[27] *Amer. Paper Inst.*, 461 U.S. at 406-07, 103 S.Ct. at 1925-26 (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).
[28] Sub 140 Order on Inputs at 30 ("The Commission has long approved the use of the peaker method for the purpose of establishing avoided costs[.]").
[29] PURPA Title II Compliance Manual 2.0, National Association of Regulatory Utility Commissioners at 72 (July 2021), https://pubs.naruc.org/pub/47AD30DC-1866-DAAC-99FB-975A60906D6B.
[30] Joint Initial Statement, DEC Exhibit 8 p 5, (Nov. 1, 2023).

energy costs are based on the variable costs of the most expensive generating unit that can be avoided in a given hour. FERC has explained that a "utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs" because "an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a [QF]."[31]

The Commission has grappled with how to account for the cost of carbon emissions several times in the past.[32] And in its Sub 175 Order, the Commission ordered the Companies to "explain in their next biennial avoided cost filings how the Carbon Plan has been incorporated into avoided cost rates and how any Commission-approved avoidable cost of carbon is factored into Duke's calculation of avoided cost rates."[33] The Companies' Joint Initial Statement argues that the Companies complied with this requirement by using the peaker methodology to calculate their avoided energy and capacity costs based on the 2023 CPIRP's Core Portfolio P3 Base (P3 Portfolio).[34] The AGO disagrees.

One of the fundamental principles of avoided cost rates is that they must represent the costs that the electric utility would have been required to spend "but for" the purchase from the QFs.[35] N.C.G.S. § 62-110.9 has altered this calculus by restraining the amount of carbon emitting resources that the Companies are able

[31] Order No. 69, *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, 45 Fed. Reg. 12,214, 12,216, F.E.R.C. ¶ 30,128 (Feb. 25, 1980) (Order 69).
[32] *See e.g.* Sub 140 Order on Inputs at 42-44 (finding "the costs [of carbon legislation] are not sufficiently certain to be included in avoided costs at this time," but that "[i]f and when such costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time.").
[33] Sub 175 Order at 71.
[34] The reference portfolio was subsequently changed to the CPIRP's Portfolio P3 Fall Base, but the Companies' argument on this issue did not change.
[35] Order 69, 45 Fed. Reg. at 12,216; N.C.G.S. § 62-156(b)(2).

to construct. It is no longer the case that the Companies could simply build CTs "but for" the contributions of carbon-free QFs.[36] Not only are there serious concerns regarding the adequacy of natural gas supply,[37] but in order to achieve the carbon emission reduction targets spelled out in N.C.G.S. § 62-110.9, the Companies would be required to account for the carbon emission impact of a carbon-free QF versus a CT.[38] Nevertheless, the Companies' avoided cost calculation does not reflect this fundamental change to resource planning under N.C.G.S. § 62-110.9.

In past avoided cost proceedings, the Commission has rejected arguments that the costs attributable to carbon emissions should be included in the Companies' avoided costs.[39] The Commission's rationale in rejecting those arguments was that only "known and verifiable" costs could be included in avoided costs. N.C.G.S. § 62-110.9 now requires the Commission to adopt—and indeed it has adopted—a plan for achieving the carbon emission reduction targets. Unlike the Companies' 2020 IRPs, which included "carbon price" in the production cost model, the carbon emission reductions in the Companies' 2023 CPIRP are based

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[36] *Californians for Renewable Energy v. California Pub. Utilities Comm'n*, 922 F.3d 929, 937 (9th Cir. 2019) (holding that PURPA "require[s] an examination of the costs that a utility is *actually avoiding*. This comports with PURPA's goal to put QFs on an equal footing with other energy providers. Where a utility uses energy from a QF to meet the utility's RPS obligations, the relevant comparable energy sources are other renewable energy providers, not all energy sources that the utility might technically be capable of buying energy from.").

[37] Concerns about the supply of natural gas supply are fundamental to PURPA's requirements. *Southern Cal. Ed. Co. San Diego Gas & Elec. Co.*, 71 FERC 61269 (FERC June 6, 1995) ("because natural gas and oil were thought to be in short supply, a principal goal of PURPA was to reduce reliance on fossil fuel sources.").

[38] *See e.g. California Pub. Utils. Comm'n S. California Edison Co. Pac. Gas & Elec. Co. San Diego Gas & Elec. Co.*, 133 FERC ¶ 61,059, 61,267 (2010) ("where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement.").

[39] *See, e.g.* Sub 140 Order at 42-44.

on known and verifiable mass caps on carbon emissions.[40] As the Public Staff has previously acknowledged, "setting a mass cap will yield a model result with an implied price on carbon, which is indicative of the cost per ton of carbon abatement."[41] In Docket No. E-100, Sub 175, the Public Staff argued that before a Carbon Plan is adopted, that implied cost of carbon cannot be accurately determined.[42] This is no longer the case—the Companies' cost of carbon can now become known and verifiable.

Moreover, prior to Virginia's withdrawal from the Regional Greenhouse Gas Initiative (RGGI), the Commission allowed the use of carbon pricing in the avoided cost rates offered by Dominion Energy North Carolina (DENC). In its Sub 175 Order, the Commission approved DENC's use of Alternative Plan B, which was the least-cost plan to achieving Virginia state law. DENC's Alternative Plan B included the RGGI's carbon price. In other words, so long as specific carbon emission reduction requirements have been in place, the Commission has found it appropriate to include carbon emission reduction costs in avoided costs rates.

In the last avoided cost proceeding, the Companies "recognize[d] 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" but argued that,

[40] Carolinas Carbon Plan, Appendix C, Docket No. E-100, Sub 190 at 7 (Aug. 17, 2023) ("DEC and DEP used the capacity expansion model with a CO2 mass cap constraint. This modeling approach enforces a limit on the amount of CO2 the particular resource portfolio is permitted to emit in operating the system.").
[41] Public Staff Initial Comments, Docket E-100, Sub 175 at 8.
[42] Sub 175 Order at 27.

at that time, "it would be premature to presume the impact of a future Commission-approved Carbon Plan in advance of such approval[.]"[43] Even so, the Companies acknowledged that upon approval of a Carbon Plan the Commission could "accept[] an avoided cost of carbon as a known and verifiable cost in a future avoided cost proceeding[.]"[44] The Commission has now approved a Carbon Plan but, in spite of this acknowledgment, the Companies' avoided cost methodology has not been updated to include its impact.

FERC has noted that "[a]voided cost rates may also 'differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.'"[45] It has also recognized that avoided costs "need not be the lowest possible avoided cost and can properly take into account real limitations on 'alternate' sources of energy imposed by state law."[46] "This means that environmental costs, if they are real costs that would be incurred by utilities, may be accounted for in a determination of avoided cost rates."[47] Therefore, in order to ensure that the Companies' avoided cost rates equal their

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[43] DEC and DEP Reply Comments, Docket. No. E-100, Sub 175 at 4 (Apr. 1, 2022).
[44] *Id.* at 21.
[45] *Cal. Pub. Utils. Comm. So. Cal. Edison Co.* 113 F.E.R.C. ¶ 61,059, 61,266 (Oct. 21, 2010) (citing 18 C.F.R. 292.304(c)(3)(ii).
[46] *Id.* at 61,262.
[47] *S. California Edison Co. San Diego Gas & Elec. Co.*, 71 F.E.R.C. ¶ 61,269, 62,080 (1995). *See also California Pub. Utilities Comm'n S. California Edison Co. Pac. Gas & Elec. Co. San Diego Gas & Elec. Co*., 134 F.E.R.C. ¶ 61,044, 61,160 (2011) ("Thus, the guidance provided by the Commission in this proceeding simply reflects the reality that states have the authority to dictate the generation resources from which utilities may procure electric energy. Just as, for example, an avoided cost rate may reflect a state requirement that utilities must 'scrub' pollutants from coal plant emissions, so an avoided cost rate may also reflect a state requirement that utilities purchase their energy needs from, for example, renewable resources. And while in theory a utility might have a cheaper source of capacity and/or energy available to it, in calculating an avoided cost rate a state may properly look at the actual sources of capacity and/or energy available to the electric utility, rather than at some theoretical source, which is not permitted by state law, that may be cheaper.").

"full avoided cost," the Commission should direct the Companies, in consultation with the AGO, the Public Staff, and other interested intervenors, to develop a method of deriving the value of carbon emission reductions from the CPIRP to be included in avoided cost rates for carbon free QFs.

The Public Staff recently advocated for a similar approach with regard to valuing carbon reduction benefits in the context of the DSM/EE mechanism. There, the Public Staff argued:

> [T]he increasing role of renewable generation tends to depress avoided energy costs without a commensurate increase to avoided capacity costs as currently calculated with the peaker methodology. A possible solution that would allow for the continued use of the peaker method is the inclusion of a carbon reduction benefits adder in the cost-effectiveness tests for DSM/EE. The Commission could approve a carbon reduction benefit of $0 in this proceeding as a placeholder for future determination in the Avoided Cost proceedings. The Commission could then direct parties to propose a calculation methodology in the next biennial avoided cost proceeding or the Companies' next biannual CPIRP proceedings, where this issue can be investigated with other considerations related to the valuation of avoided costs and included in future DSM/EE program evaluations.[48]

The AGO takes no position on the appropriate method to quantify the value of carbon emission reductions at this time. However, the AGO notes that valuing emissions reductions is not a new concept—the Companies' avoided energy costs have long included the emission allowance costs for many other air pollutants, including NO_X and SO_2.[49] FERC has long acknowledged that accounting for these types of costs is permissible:

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[48] Public Staff's Comments, Docket Nos. E-2, Sub 931, E-7, Sub 1032, and E-100, Sub 179 at 43-44 (Jan. 26, 2024).

[49] *See e.g. Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 100 (Sept. 29, 2005) (noting that Duke "currently includes emissions allowance costs for NOx and SOx in the calculation of its avoided energy

> [E]nvironmental costs, if they are real costs that would be incurred by utilities, may be accounted for in a determination of avoided cost rates. . . . Thus, in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities. A state may, through state action, influence what costs are incurred by the utility. Thus, accounting for environmental costs may be part of a state's approach to encouraging renewable generation.

Southern Cal. Ed. Co. San Diego Gas & Elec. Co., 71 FERC 61269 (FERC June 6, 1995). Therefore, there are methods available to accurately quantify these values and have them reflected in avoided cost rates.

In its Sub 175 Order, the Commission directed all parties "to evaluate before the next biennial proceeding whether to propose an alternative method to calculate avoided costs, including those FERC has recently determined to be reasonable and appropriate for calculating avoided costs in Order No. 872 and that are now included in 18 C.F.R. 292.304(b)."[50] In Sub 175, the Public Staff noted that:

> [T]here may come a time when the peaker methodology is not appropriate for use in North Carolina. As utilities seek decarbonization, generation will increasingly come from renewable resources, such as wind and solar, that have high capital costs and low variable costs. . . . At some point, the Public Staff believes it may be appropriate to either look to other resources to determine the avoided cost of capacity or adopt a new methodology which reflects the changing energy landscape.

The AGO believes it is possible to account for the value of carbon emissions reductions within the peaker methodology. However, if the Commission disagrees and finds it is not possible to accurately reflect carbon emissions reductions using the peaker methodology, then N.C.G.S. § 62-110.9 and PURPA require the Commission to discontinue the use of the peaker methodology rather than

credits" in order to "reflect[] the current economic value of the environmental benefits of renewable resources under North Carolina and federal law.").

[50] Sub 175 Order at 14-17.

approving avoided cost rates that do not accurately reflect their value. N.C.G.S. § 62-110.9 requires that the Commission "shall take all reasonable steps" to meeting carbon emissions reduction targets. Similarly, FERC's regulations mandate that avoided cost rates be set "at a rate equal to the utility's full avoided cost,"[51] and that "State laws or regulations" that do otherwise "fail to provide the requisite encouragement of these technologies, and must yield to federal law."[52]

The continued use of the peaker methodology after the adoption of a Carbon Plan may cause a "mismatch of generation expansion plans and avoided energy inputs" and thus "distort the avoided energy calculations and result in a miscalculation of avoided energy costs."[53] In its Sub 140 Order, the Commission noted this potentially distortive effect, observing that the inclusion of carbon prices in resource planning could result in additional high-capital cost, low-energy cost nuclear generation.[54] This growing disconnect is evidenced by the fact that the Companies' avoided costs calculation is based on the cost of an F-class CT, yet the Companies seem to recognize that an F-class CT is no longer a valid comparative capacity resource under N.C.G.S. § 62-110.9's framework given that they fail to include the same as a selectable resource in the Companies' most recently filed CPIRP.[55] Nor is the use of an F-class CT consistent with the Companies' proposal for calculating system benefits under the demand-side

[51] *Amer. Paper Inst.*, 461 U.S. at 402, 103 S.Ct. at 1923.
[52] Order 69, 45 Fed. Reg. at 12,221.
[53] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 140 at 23 (Dec. 15, 2015) (Sub 140 Order).
[54] *Id.*
[55] Companies Response to Public Staff Data Request 5-11 (attached as AGO Exhibit 1).

management and energy efficiency mechanism, which uses a Hydrogen-Capable Advanced Class CT to calculate avoided capacity costs.[56]

The Companies' NEEC is calculated using the avoided costs rates for uncontrolled solar generators connected at the distribution level and annualized over a 5-year term.[57] As described above, because the NEEC is based on the Companies' avoided cost rates, this rate does not fully reflect the carbon emission reductions that rooftop solar provides to the Companies. This undervaluation of rooftop solar is especially concerning in the context of net metering given that Part IV of House Bill 589, codified as N.C.G.S. § 62-126.4, requires that Commission-established net metering rates reflect the costs and benefits of customer-sited generation. The Companies' have previously stated that the goal of net metering rates is to "send accurate price signals through rate design that recover embedded costs *while encouraging customers to provide the maximum amount of value to the system.*"[58] Without a recognition of the value of carbon emissions reduction, a key benefit of distributed generation is not being valued and customers are not being fully incentivized to provide the maximum value to the system.

Failure to accurately reflect the value of carbon emission reductions in avoided costs rates poses a risk to all ratepayers. Carbon-free QFs and net metered rooftop solar "can avoid air pollution and carbon emissions. The avoided costs of these externalities should be treated consistently. Inconsistency in how these externalities are valued among resources could lead to inefficient investment

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[56] Initial Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket Nos. E-2, Sub 931, E-7, Sub 1032, E-100, Sub 179 (Jan. 26, 2024).
[57] *Order Establishing Net Excess Energy Credit*, Docket No. E-100, Sub 175 (Aug. 4, 2023).
[58] Joint Reply Comments, Docket No. E-100, Sub 180 (May 2, 2022) (emphasis added).

and thus raise electricity prices more than necessary."[59] Therefore, the Commission should establish an avoided cost and NEEC that (1) aligns with the costs the Companies would incur to meet statutory carbon reduction mandates in the absence of carbon-free QFs and residential rooftop solar, and thus (2) places those resources on an even playing field with supply side renewables which the utility must otherwise purchase in their absence.[60]

III. THE COMMISSION SHOULD DIRECT THE COMPANIES TO USE THE CPIRP PORTFOLIO P1 FALL SUPPLEMENT FOR THE PURPOSES OF CALCULATING AVOIDED COST RATES AND FILE UPDATED AVOIDED COST RATES ONCE THE COMMISSION APPROVES AN UPDATED CPRIP.

The Companies' initial proposed avoided cost rates used the 2023 CPIRP's Portfolio P3 Base in order to determine both the next capacity need as well as avoided energy rates.[61] The Companies subsequently changed the reference portfolio to CPIRP Portfolio P3 Fall Base.[62] The Commission has previously required that Dominion Energy North Carolina (DENC) base its avoided energy rates on "the least-cost plan that complies with all applicable state law."[63] The Companies' CPIRP Portfolio P3 Fall Base does not comply with N.C.G.S. § 62-110.9 and therefore cannot constitute "the least-cost plan that complies with all applicable state law."

[59] *The Role of Net Metering in the Evolving Electricity System*, National Academies of Sciences, Engineering, and Medicine (2023), https://doi.org/10.17226/26704.
[60] *See id.* pp 85 n. 60, 90, 170 ("[R]egulators in states with carbon-reduction commitments need to establish the carbon-reduction value of on-site [distributed generation] consistent with the incremental costs to comply with their state's clean energy policy and/or consistent with subsidies or incentives provided to other sources of zero-carbon electricity supply.").
[61] Joint Initial Statement, DEC Exhibit 8 p 2 (Nov. 1, 2023).
[62] *See* Letter to the Commission re: Updates to Avoided Cost Rates, Docket No. E-100, Sub 194 (Feb. 15, 2024).
[63] Sub 175 Order at 28.

As was argued extensively by the AGO in the initial Carbon Plan proceeding, the plain language N.C.G.S. § 62-110.9 requires the development of a plan for reducing the carbon dioxide emissions attributable to electric generating facilities in the State by 70% by the year 2030. CPIRP Portfolio P3 Fall Base does not achieve that target until 2035.[64] The Commission retains limited discretion under N.C.G.S. § 62-110.9(4) to delay the 2030 target: (1) by up to two years "in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction," (3) by more than two years if "the Commission authorizes construction of a nuclear facility or wind energy facility" and if additional time is necessary to complete that facility "due to technical, legal, logistical, or other factors beyond the control of the electric public utility," or (3) by more than two years if "in the event necessary to maintain the adequacy and reliability of the existing grid." The AGO incorporates by reference the arguments on this issue made at pages 7 through 18 of its post-hearing brief to the Commission in Docket No. E-100, Sub 179. The Companies have put forward no evidence demonstrating that the above conditions necessary to delay the 2030 targets have been met.

The Commission's discretion to delay the 2030 carbon emission reduction targets will almost certainly be fiercely litigated in the upcoming Carbon Plan docket and the AGO does not believe it is proper or a prudent use of the Commission's time to attempt to definitively answer that question in this limited proceeding. However, it cannot be appropriate for the Companies to use CPIRP

[64] Carolinas Carbon Plan, Supplemental Analysis, Docket No. E-100, Sub 190 at 35 (Jan. 31, 2024).

Portfolio P3 Fall Base as the basis for its avoided cost calculation given its failure to comply with N.C.G.S. § 62-110.9's statutory mandates. Just as it would be inappropriate to base avoided cost rates on a portfolio that fails to meet NERC reliability standards, it is inappropriate to base them on a portfolio that does not and cannot meet our state's carbon emission reduction targets. Simply put, CPIRP Portfolio P3 Fall Base does not represent "the least-cost plan that complies with all applicable state law."

Given the Companies' CPIRP is the subject of a pending proceeding, the AGO believes it would be more appropriate to use the Companies' proposed CPIRP Portfolio P1 Fall Supplement, which achieves 70% carbon emissions reductions by 2030, as the basis for the Companies' avoided cost rates. The Companies should be directed to recalculate their avoided cost calculations based on Portfolio P1 Fall Supplement.[65]

This issue is complicated by the fact that the Commission is being asked to base avoided cost rates on a CPIRP that will not be approved until nearly 14 months after the Companies filed their initial proposal in this docket. At the time of comment filing, the Commission's initial Carbon Plan is also over 13 months old. Given that the Companies have also filed an updated CPIRP with significant revisions, it is also not appropriate to use the Commission's initial Carbon Plan for the purposes of calculating avoided cost rates. In order to more closely align these avoided cost proceedings with approved—rather than proposed—CPIRPs, the Commission should direct the Companies to recalculate their avoided cost

[65] While the Companies' CPIRP contains a quantification of their next avoidable capacity need for Portfolio P3 Base, it does not contain such a statement for any other portfolio.

calculations within 90 days of the Commission's approval of its next and subsequent CPIRPs.

IV. CONCLUSION

For the reasons discussed in these comments, the AGO respectfully recommends that the Commission:

1. Direct the Companies, in consultation with the AGO, the Public Staff, and other interested intervenors, to develop a method of deriving the value of carbon emission reductions from the CPIRP to be included in avoided cost rates for carbon free QFs;
2. In the alternative, if the Commission determines that it is not possible to accurately reflect the value of carbon emission reductions with the peaker methodology, direct the Companies, in consultation with the AGO, the Public Staff, and other interested intervenors, to propose an alternative method for calculating avoided cost rates;
3. Direct the Companies to use the CPIRP Portfolio P1 Fall Supplement for the purposes of calculating avoided cost rates;
4. Direct the Companies to file updated avoided cost rates based on the Commission's approved CPRIP in Docket No. E-100, Sub 190 within 90 days of the issuance of a final order in that docket;
5. Direct the Companies that in future proceedings, avoided cost rates should be updated based on the most recently approved CPIRPs and updated within 90 days of the Commission's approval of a CPIRP.

Respectfully submitted this the 21st of February, 2024.

JOSHUA H. STEIN
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CERTIFICATE OF SERVICE

The undersigned certifies that he has served a copy of the foregoing COMMENTS OF THE ATTORNEY GENERAL'S OFFICE upon the parties of record in this proceeding by email, this the 21st day of February, 2024.

/s/ Tirrill Moore
Assistant Attorney General

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide a justification for the Company's use of an F-class CT for avoided capacity, given that the 2023 CPIRP does not permit the model to select F-class CTs and the Company appears to no longer consider these viable options.

a. In addition, please also address the Company's proposed use of an advanced class CT in the DSM/EE Mechanism Review, and why the Company does not believe alignment between avoided capacity costs between PURPA QFs and DSM/EE is necessary.

Response:

The Companies are required to use data from publicly available industry sources for the avoided capacity cost of the CT (Docket No. E-100, Sub 140, NCUC Order on Inputs dated December 31, 2014, ordering paragraph 6, at 65). As noted in the Companies' Joint Initial Statement, prior to making their initial filing in the 2021 Sub 175 proceeding, DEC and DEP worked with the Public Staff and DENC to develop the methodology for calculating CT cost estimates using publicly available sources, such as EIA, as directed by the Commission in its Sub 158 Order (Sub 158 Order at 32-33). The parties arrived at a consensus standardized approach to streamline the determination of the avoided CT capacity cost in a manner that fairly values the avoided capacity cost for QFs while ensuring customers do not overpay for capacity. The Commission found the approach to be "reasonable, consistent with prior Commission orders, and appropriate for the purposes of calculating avoided capacity costs[,]" (Sub 175 Order at 14) and the Companies have implemented the same standardized approach in this proceeding.

Duke's avoided capacity cost is based on publicly available EIA data for an F-frame CT. The current EIA publication (EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023) does not include an Advanced Class Frame CT similar to that used in development of the Companies' 2023 Carolinas Resource Plan. However, based on the Companies' technology cost estimates developed by a third-party provider, the difference in the overnight capital cost ($/kW) of an Advanced Class Frame CT and an F-Frame CT is approximately 3%. Due to the larger size of the Advanced Class Frame CT, this comparison assumes a 2-unit Advanced Class Frame CT configuration compared to a 4-unit F-Frame CT configuration. Thus, there is not a significant difference in the overnight capital cost ($/kW) of constructing an Advanced Class Frame CT versus an F-Frame CT, with the cost of the Advanced Class Frame CT being slightly lower than the F-Frame CT. In addition, if public data was available for an Advanced Class Frame CT for use in calculating the avoided capacity cost, the greater efficiency and lower heat rate associated with the Advanced Class Frame CT versus F-Frame CT would necessitate consideration of a net cost of new entry (net CONE) approach which would further lower the avoided capacity cost.

The Companies believe that the publicly available EIA data for an F-frame CT continues to be an appropriate proxy unit to be used as the basis for the avoided capacity cost filed in Docket No. E-100, Sub 194.

a. With respect to using the avoided cost methodology approved in the Commission's biennial Public Utility Regulatory Policies Act ("PURPA") proceedings for evaluating avoided capacity benefits provided by DSM/EE measures, the Commission has previously noted that evaluating the contributions that DSM/EE measures make to a utility's avoided future capacity needs to determine cost-effectiveness is "inherently different" than evaluating the capacity costs avoided through the purchase of electric output from a QF. Order Approving DSM/EE Rider and Requiring Filing of Customer Notice, Docket No. E-7, Sub 1164, issued Sept. 11, 2018 at 44. (But see fn. 17.)
In the Commission's 2022 Carbon Plan Order, the Commission further acknowledged that certain enablers, including an update to the inputs underlying the determination of utility system benefits, were identified by Duke Energy as necessary to achieve greater load reduction for the energy transition. The Companies believe that their proposed update to calculating the value of the avoided capacity benefits in the EE/DSM Mechanism aligns the economic framework with the way that energy efficiency ("EE") creates customer value in the Carbon Plan Integrated Resource Plan ("CPIRP"). The Companies' proposed modernization of the EE/DSM Mechanism with respect to determining system benefits is intended to (i) fully recognize EE as a first priority resource in the CPIRP, resulting in system benefits that EE (as opposed to the Companies investing in a supply-side resource) provides in shrinking the challenge during the energy transition and (ii) enable the Companies to achieve the aggressive, long-term modeling assumptions around EE that the Commission found to be reasonable in the 2022 Carbon Plan Order. (2022 Carbon Plan at 105-06.) Recognizing the increased system benefits resulting from EE in the energy transition will enable additional EE in two ways. First, the higher system benefits will allow the Companies to potentially increase program incentives to promote additional participation while maintaining programs' cost-effectiveness. Second, recognizing the appropriate system benefits under the updated methodology proposed by the Companies will also allow them (with the DSM/EE Collaborative's input and feedback) to offer additional programs and measures that were previously not cost effective. Thus, the proposed methodology for evaluating non-QF contributions to the utility system during the energy transition differs from the methodology proposed for calculating the avoided capacity cost rates for QF contributions to the system under the Commission's PURPA framework.

Responders: 5-11: Tom Davis, Principal Planning Analyst
5-11(a): Kendrick Fentress, Director Regulatory Strategy & Alignment