NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

February 21, 2024

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

Re: Docket No. E-100, Sub 194 – In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2023

Dear Ms. Dunston:

Attached for filing on behalf of the Public Staff in the above-referenced docket is the **public version** of the Initial Statement of the Public Staff.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. Confidential information is located on pages 24-28, 36, 44, and 47. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
s/ Robert B. Josey
Staff Attorney
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Attachment

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Initial Statement of the Public Staff

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2023

Docket No. E-100, Sub 194

February 21, 2024

INTRODUCTION

On November 9, 1978, the United States Congress enacted the Public Utilities Regulatory Policy Act (PURPA) as part of the National Energy Act. Section 210 of PURPA and the subsequent regulations by the Federal Energy Regulatory Commission (FERC) require electric utilities to purchase electric power from cogeneration and small power production facilities that obtain qualifying facility (QF) status under PURPA. For such purchases, a utility is required to pay avoided cost rates that reflect the costs that it can avoid by obtaining the energy and capacity from QFs, rather than generating the electricity itself or buying it from other suppliers. QFs and the electric utilities use purchased power agreements (PPAs) to set their contractual obligations.

Since the passage of PURPA and the enactment of N.C. Gen. Stat. § 62-156 (entitled "[p]ower sales by small power producers to public utilities") by the North Carolina General Assembly in 1979, the Commission has held biennial proceedings to determine the avoided cost rates, terms, and conditions for North Carolina utilities.

Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC, and together with Duke, the Utilities), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Light and Power Company (NRLP), are parties to the avoided cost proceedings.

On August 7, 2023, the Commission initiated the current avoided cost proceeding in its *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* in the above-captioned docket, which required WCU, NRLP, and the Utilities to file their requested avoided cost rates and standard forms for QFs on or before November 1, 2023. WCU, NRLP, and the Utilities complied with the order.

The Public Staff's comments below are organized as follows:

I. Issues from the E-100, Sub 175, Avoided Cost Proceeding
   a. Inclusion of Solar and Wind Generator Outage Data in the Performance Adjustment Factor
   b. Inclusion of the Carbon Plan in Avoided Cost Rates
   c. QFs Attempting to Avoid the Solar Integration Services Charge
   d. Provision of Ancillary Services by Inverter Based Resources
   e. Direct Current Revenue-Grade Meters and Energy Storage System Retrofits

II. New Issues
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III. Utilities' Proposed Rates
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   b. Avoided Cost of Capacity
   c. CoAvoided Cost of Energy
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IV. WCU's and NRLP's Proposed Rates

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VI. Conclusions and Recommendations

I. Issues from the E-100, Sub 175, Avoided Cost Proceeding

The previous avoided cost proceeding in Docket No. E-100, Sub 175 (Sub 175 Proceeding) resolved certain outstanding issues and raised others. In the Sub 175 Proceeding, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 175 Order) and required that five items be addressed in the next avoided cost proceeding as follows:

> 10. That DEC, DEP, and DENC shall address the inclusion of solar and wind generator outage data in the PAF [Performance Adjustment Factor] calculation in future avoided cost proceedings;
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> …
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> 14. That DEC and DEP shall 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;
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> …
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> 16. That Duke shall file a report on QFs that attempt to avoid the SISC [Solar Integration Services Charge], and include an analysis of actual solar volatility reductions of QFs that avoid the SISC in Duke's service territories in future avoided cost filings, and also address QFs seeking SISC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of SISC credits issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC;
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> …
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> 18. That DEC and DEP shall conduct a preliminary investigatory study of the operating characteristics of inverter-based resources (IBR) at certain of its own IBR facilities to understand which ancillary services can be provided by each resource or combination or resources and shall file a report on its findings with the Commission in a new docket on or before August 1, 2023;
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> …
>
> 27. That Duke shall file in Docket No. E-100, Sub 158 an update advising the Commission when DC [direct current] revenue-grade meters become available for use for energy storage retrofits;

a. Inclusion of Solar and Wind Generator Outage Data in the PAF

The Utilities collect capital costs for their generators even when the generators have outages. The PAF is a per kWh multiplier to avoided cost rates that allows QFs to collect revenues that are adjusted upward for their outages in an effort to approximate the amount of revenue that the Utilities receive during their generator outages. Allowing QFs to collect avoided cost payments plus the PAF allows QFs to be fairly compensated even if they have outages during times of peak demand.

In the current proceeding, Duke stated the following in its Joint Initial Statement:

> Prior to making their initial filing in the 2021 Sub 175 proceeding, [Duke] worked with DENC and the Public Staff to consider the use of appropriate reliability metrics for developing the PAF. These discussions resulted in a consensus to adopt the Weighted Equivalent Unplanned Outage Factor ("WEUOF") metric for each utility's respective generation fleet to calculate the PAF, and the Commission approved this consensus approach in its Sub 175 Order.

To calculate their WEUOF, the Utilities use the Generating Availability Data System (GADS) developed by the North American Electric Reliability Corporation (NERC). GADS did not begin collecting availability data for solar facilities until January 1, 2024.[1] Therefore, the Utilities do not currently have enough information to use solar availability to calculate the PAF. NERC has required wind turbine generators to report outage data to GADS since 2018, but North Carolina has only

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[1] See GADS Solar Generation Data Reporting Instructions, effective date of January 1, 2024, accessible at: https://www.nerc.com/pa/RAPA/PA/Section1600DataRequestsDL/2024_GADS_Solar_DRI.pdf

one wind facility in operation. The Public Staff expects that the Utilities will begin utilizing solar outage data in the calculation of their PAF in the next avoided cost proceeding.

b. Inclusion of the Carbon Plan in Avoided Cost Rates

In the 2020 avoided cost proceeding, Docket No. E-100, Sub 167 (Sub 167 Proceeding), the Commission found Duke's calculation of avoided energy rates using inputs from each company's 2020 IRP, which did not reflect a carbon price, to be appropriate because the Commission had previously directed that only known and verifiable costs should be considered in the avoided cost rates.[2] However, on October 13, 2021, House Bill 951, Session Law 2021-165 (House Bill 951), was enacted. Among other things, House Bill 951 required the Commission to develop a plan no later than December 31, 2022, for Duke to take all reasonable steps to reduce emissions of carbon dioxide from in-state electric generation facilities that it owns or operates. In accordance with House Bill 951, Duke must reduce 2005 emissions by 70% by the year 2030, as well as achieve carbon neutrality by the year 2050.[3]

On November 19, 2021, the Commission issued its Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines in Docket No. E-100, Sub

[2] *See* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020*, Docket No. E-100, Sub 167, at 7 (Aug. 13, 2021).

[3] The law provides some flexibility, specifically allowing the Commission to delay compliance of the 2030 target by two years or more if necessary to maintain the adequacy and reliability of the electric grid or to provide additional time to allow for implementation of solutions that would have a more significant and material impact on carbon reduction.

179. In its Initial Comments in that Proceeding, the Public Staff did not propose a calculation methodology for the avoidable cost of carbon, noting the complexities of determining an accurate avoidable cost of carbon applicable to the avoided energy rate.[4] No other parties proposed a calculation methodology for the avoidable cost of carbon.

On December 30, 2022, the Commission issued its Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan), in which the Commission required Duke to file a new carbon reduction plan on or before September 1, 2023. The Commission also combined Duke's carbon reduction plan requirements with integrated resource plan requirements into a combined Carbon Plan – Integrated Resource Plan (CPIRP) proceeding.

Duke filed its CPIRP on August 17, 2023, in Docket No. E-100, Sub 190 (CPIRP Proceeding).

Since the Sub 167 Proceeding, the costs for reducing carbon emissions have become more known and verifiable. In the present proceeding, Duke addressed the Commission's requirement to include the avoidable cost of carbon in avoided cost rates in its Joint Initial Statement, in which it states: "To appropriately incorporate the CPIRP into [Duke's] avoided costs, [Duke] calculated their avoided energy and capacity costs using data from the 2023 CPRIP Core

[4] *See* Initial Comments of the Public Staff, filed July 15, 2022, at 142-145.

Portfolio P3 Base ("Portfolio P3"), which is the reference portfolio identified in [Duke's] most recent biennial CPIRP filed with the Commission."

On December 18, 2023, Duke filed a letter in the CPIRP Proceeding stating that it intended to update its CPIRP based upon significant and unexpected increases in its load forecast (CPIRP Update) and included a proposed proceeding schedule. In a discussion with the Public Staff on January 10, 2024, Duke stated that it would update the calculated avoided energy rates in this avoided cost proceeding based upon the CPIRP Update. Duke filed its CPIRP Update on January 31, 2024, which is currently under review. In addition, to ensure that the avoided cost rates in this proceeding align with the changes made in the CPIRP Update, Duke filed updated avoided cost rates (Updated Rates) on February 15, 2024.[5]

With regard to the Utilities' efforts to quantify carbon emission reduction benefits, Duke's carbon-constrained capacity expansion plan in CPIRP does consider the carbon cap but may not fully capture the avoided costs of carbon compliance in the future. In its Initial Comments in Docket Nos. E-2, Sub 931; E-7, Sub 1032; and E-100, Sub 179 (DSM/EE Mechanism Review),[6] the Public Staff stated that the generation expansion plans subject to a carbon emission limit would include lower emitting resources that tend to have lower marginal energy costs and higher capital costs per kW of capacity. These lower carbon emitting resources

[5] The Public Staff is currently reviewing the Duke's Updated Rates and will make further comments regarding Duke's Updated Rates in its Reply Comments if necessary.

[6] Public Staff Initial Comments at 43, filed January 26, 2024.

reduce avoided energy costs without a commensurate increase to avoided capacity costs as calculated under the peaker methodology. To address this reduction, the Public Staff noted that the Commission could approve a carbon reduction benefits adder for avoided energy rates, initially set at $0 per MWh as a placeholder, and direct parties to propose a calculation methodology in the next biennial avoided cost proceeding or Duke's next CPIRP filing. This adder could help recognize the full measure of benefits provided by renewable energy QFs and Energy Efficiency/Demand Side Management measures.

DENC does not have any requirements under House Bill 951, but the Commonwealth of Virginia promulgated its Virginia Clean Economy Act (VCEA) in 2020, which, in part:

> Establishes a schedule by which Dominion Energy Virginia and American Electric Power are required to retire electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity and by which they are required to construct, acquire, or enter into agreements to purchase generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind.

DENC calculated the avoided energy rates utilizing its Expansion Plan B from its 2023 IRP filing in Docket No. E-100, Sub 192. Expansion Plan B is a least-cost plan that only partially complies with the VCEA. Expansion Plan E is the least-cost plan that complies with the VCEA. While the Public Staff recommended that the Commission not approve any of the DENC IRP Plans in Docket No. E-100, Sub 192,[7] the Public Staff did recommend that the Commission find DENC's short-term action plan reasonable for planning purposes and these avoided cost rates are based on the energy and capacity needs of the utility over the next ten years. Therefore, the Public Staff believes that Plan E is appropriate for use in calculating its avoided energy rates in this proceeding. In previous avoided cost proceedings, DENC included the carbon emission reduction effects of Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI); however, Virginia exited RGGI on December 31, 2023.

c. QFs Attempting to Avoid the SISC

The SISC provides payment to Duke and its customers for the additional capacity and energy necessary to compensate for the intermittent nature of solar energy and keep the grid stable. At present, no QFs have contracted to sell QF power as a controlled solar generator to avoid the SISC.

d. Provision of Ancillary Services by IBRs

The United States Energy Information Administration (EIA) defines ancillary services as "[s]ervices that ensure reliability and support the transmission of electricity from generation sites to customer loads," including "load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage

[7] Comments of the Public Staff on the 2023 Biennial Integrated Resource Plan of Dominion Energy North Carolina and 2023 REPS Compliance Plan of Dominion Energy North Carolina at 8, filed January 19, 2024.

support." Ancillary services are additional to the customers' need for capacity and energy.

On August 1, 2023, Duke filed its IBR Testing Report (Report) in the Sub 175 Proceeding,[8] which describes Duke's efforts to provide ancillary services using its Elm City and Monroe solar facilities and the Asheville Rock Hill battery. Duke stated in the Report's recommendations that it believes "further study and testing of different Duke-owned IBR resource types such as standalone batteries and solar plus storage, (resource types that will be significant in the future resource mix), will help determine whether a pilot program would be worthwhile."

Attached to these comments as **Appendix 1** is Duke's response to Public Staff Data Request 4-10, which provides a summary of its IBR Testing Report and Duke's future testing plans. In its response, Duke stated that "[r]eactive power management/voltage support is a service based on locational needs" and that "[t]his service has been provided successfully by transmission connected solar following a voltage schedule within power factor limits for several years now." **Appendix 2** is Duke's response to Public Staff Data Request 4-11, which provides a summary of an IBR ancillary service test completed in California. **Appendix 3** is Duke's response to Public Staff Data Request 5-2, which provides more detail on battery system ability to provide ancillary services.

[8] Accessible at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=8dfa4208-c521-4e63-bf25-af8e1ff43424

The Public Staff's review of the IBR Testing Report reveals the need for research using larger scale batteries, which are not subject to the sunlight variations that affect solar facilities. Transmission-connected solar facilities can provide some ancillary services, but energy storage will likely be necessary if QFs are to provide significant ancillary services in the future.

e. DC Revenue-Grade Meters and Energy Storage System Retrofits

In the 2019 avoided cost proceeding in Docket No. E-100, Sub 158 (Sub 158 Proceeding), some intervenors proposed allowing existing QFs to retrofit energy storage systems (ESS Retrofits) and sell energy and capacity to Duke from their ESS Retrofits. On April 15, 2020, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Order), in which the Commission required Duke to hold stakeholder meetings to address the option of QFs adding ESS Retrofits.

Duke held the stakeholder meetings and, on September 29, 2021, in Docket No. E-100, Subs 101 and 158, Duke filed its ESS Retrofit Compliance Filing proposing a framework for ESS Retrofits.

On July 31, 2023, Duke filed an update on participation in ESS Retrofits in Docket No. E-100, Subs 101 and 158. At present, Duke has not received any applications or notices of commitment forms for ESS Retrofits. Duke requested that the Commission allow the rates for ESS Retrofits in the Sub 175 Order to expire and be discontinued. The Public Staff agrees due to the lack of interest by QFs and the adoption of cluster studies under queue reform. Any QF wishing to add battery storage to an existing facility can submit an interconnection request to one of Duke's annual Definitive Interconnection System Impact Study clusters.

II. <u>NEW ISSUES</u>

a. Peaker Method and Type

In past biennial avoided cost proceedings, the Commission has consistently approved use of the peaker method, which estimates avoided capacity costs for the Utilities by using the capital costs of the lowest-cost capacity option available to the utility, typically a peaking unit such as a combustion turbine (CT). CTs combust fuel in a series of blades on a shaft. The resulting force spins the shaft which is connected to a generator producing electricity. CTs were first utilized in the 1940s and typically use letter and/or number designations for generators with increased capacity and efficiency. The Utilities have chosen F-frame CTs as the basis for their peaker-method calculations. F-frame CTs entered service in 1990 and are still widely used for power generation; however, advanced class (or H-Class) CTs are becoming increasingly available and will likely replace F-frame CTs in the future as the preferred source of peaking capacity. The higher efficiency of H-class CTs will likely allow them to be used as a source for energy, not just capacity.

Cost 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. In January 2024, the EIA released its *Capital Cost and Performance Characteristics* *for Utility-Scale Electric Power Generating Technologies* (EIA 2024 Report),[9] which included cost estimates for H-Class CTs. However, H-class CTs currently have limited available data on their operations and actual construction costs. As such, the Public Staff supports the use of an F-frame CT as proposed by the Utilities in this proceeding. However, if no other publicly available cost data exists, the Public Staff recommends that the Utilities calculate their avoided capacity payments based upon more advanced CTs in the next avoided cost proceeding, along with an offset to the cost of the unit based upon the energy value associated with an advanced CT, should such an adjustment be found to be material – a calculation known as the "net peaker" method.

b. Net Excess Energy Credit

On March 23, 2023, the Commission issued its Order Approving Revised Net Metering Tariffs in Docket No. E-100, Sub 180 (Net Metering Order)[10] in which it stated that it will establish the method that the Utilities will use to compensate net metered customers for excess generation in avoided cost proceedings, recognizing that net metered customers sometimes generate excess energy during a billing cycle and should be compensated by receiving a net excess energy credit (NEEC) that is based on avoided costs. Accounting for the benefits of net metered generation, the NEEC reflects avoided energy and avoided capacity

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[9] Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

[10] The Net Metering Order was appealed and is currently awaiting the issuance of an opinion by the North Carolina Court of Appeals (COA), COA No. 23-760. The Commission, however, issued an *Order Denying Motion for Stay Pending Appeal* on June 16, 2023, and therefore, the NEEC should not be affected until and unless the COA reverses or remands the Commission's March 23 Order.

calculated over a five-year term, inclusive of the distribution line-loss adder and fuel hedging value, with energy rates weighted to a generic rooftop solar output profile. The Net Metering Order also requires the Utilities to “net exports against consumption in the same pricing periods, including the CPP [Critical Peak Pricing] periods, and shall be netted monthly.”

To determine the NEEC, Duke has proposed a five-year term in a manner consistent with the two- and ten-year fixed term rates shown on Schedule PP as required by the Commission’s Order Establishing Net Excess Energy Credit for NEM Tariff issued on August 4, 2023, in the Sub 175 Proceeding. In the current docket, Duke presented its NEEC rates for DEP and DEC in their respective Exhibit 11s. Duke updated its NEEC on February 15, 2024. The proposed NEEC included in the update filing is 4.4 cents/kWh for DEC and 3.9 cents/kWh for DEP, on an annualized basis.[11] The Public Staff recommends that the Commission approve the NEEC in the update filing.

c. PAF for Hydroelectric QFs

In the Sub 175 Order, the Commission stated that it “may consider whether to discontinue the 2.0 PAF for run-of-river Hydro QFs based upon evidence presented in the next avoided cost proceeding.” In the past, run-of-river hydroelectric QFs have had a PAF of 2.0[12] based upon the Commission’s Order

[11] In its Initial Filing, DEC proposed a NEEC of 3.99 cents/kWh and DEP proposed a NEEC of 3.77 cents/kWh.

[12] Prior to Session Law 2017-192’s (House Bill 589) enactment, the statutory definition of small power producer was limited to hydroelectric renewable resources. *See* 2017 N.C. Sess. Laws 2017-192, Part I (amending N.C.G.S. § 62-3(27a)).

Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 79, issued on June 19, 1997. In the avoided cost proceeding in Docket No. E-100, Sub 140, Duke agreed in a stipulation to continue the 2.0 PAF in avoided cost proceedings filed before December 31, 2020. Since this portion of the stipulation has expired, Duke requests that the PAF for hydroelectric QFs be the same as for other QFs. To preserve fairness to other QFs and to Duke's customers that pay for QF power, the Public Staff supports Duke's request.

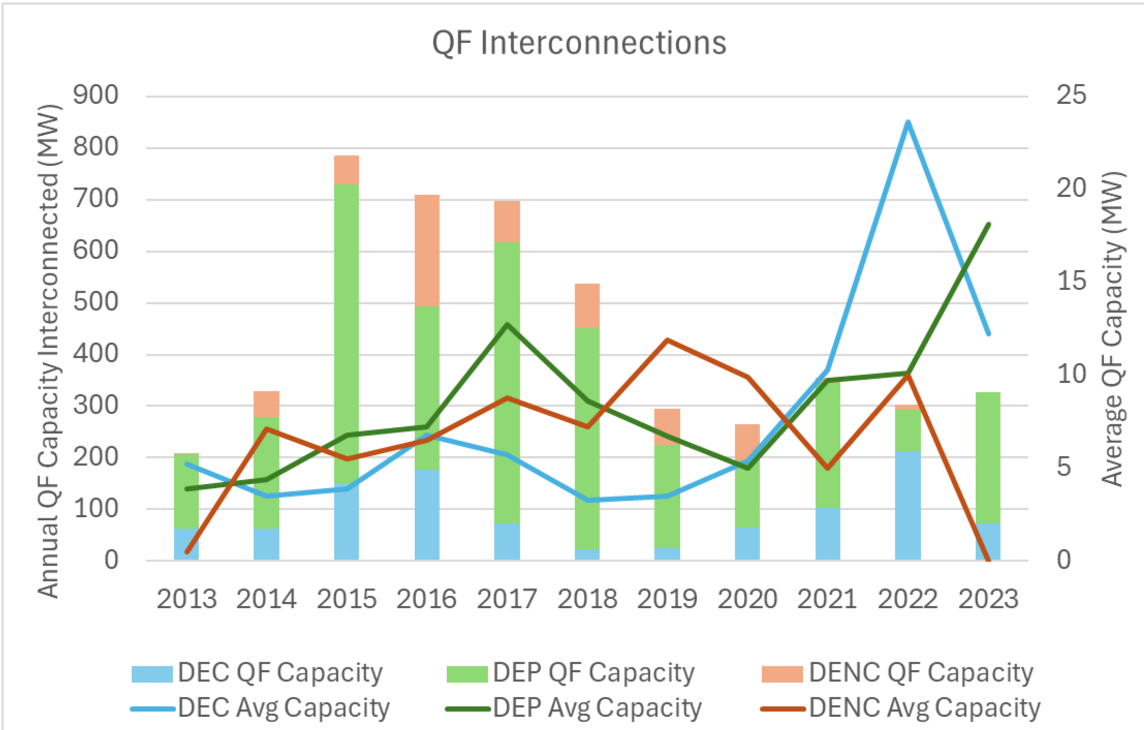
d. Reduction in Number and Capacity of New QFs

The number and capacity of new QFs being paid avoided cost rates in the Utilities' territories has decreased over time, with only 38 QFs with a combined capacity of 630 MW interconnecting in 2022 and 2023.[13] This decreasing trend is shown in **Figure 1**, below. This decrease is likely due to a variety of factors, including: (1) the expiration of the State's renewable energy investment tax credit in 2016; (2) the passage of House Bill 589 in 2017, which reduced the standard offer term length to ten years and limited QFs eligible for the standard offer to 1 MW; (3) a general reduction in avoided cost rates from 2018 through 2022; (4) the competitive procurement of large-scale transmission connected solar facilities through the recently concluded Competitive Procurement of Renewable Energy (CPRE) program; and (5) the ongoing competitive procurements under House Bill 951 and Duke's Carbon Plan requirements. Most QF capacity is uncontrolled

[13] This figure includes approximately 500 MW of projects procured through the Competitive Procurement of Renewable Energy Program, as those projects are designated as QFs but are paid less than avoided cost rates.

solar,[14] which makes up 100% of DENC QFs, 97% of DEP QFs, and 94% of DEC QFs.

Figure 1: QF Interconnections, 2013 - 2023



[14] Uncontrolled solar is defined as solar generation where the QF cannot or does not demonstrate its ability to reduce average daylight volatility to 6% or less of its average daylight power output. Uncontrolled solar is subject to the Solar Integration Service Charge. The utility must purchase 100% of a QF's output except in instances where it must be curtailed due to system emergencies. QFs that sell power under the CPRE Program can be economically curtailed up to an annual limit, currently 5% of annual power output in DEC and 10% in DEP.

III. UTILITIES' PROPOSED RATES

a. Summary of Avoided Cost Rates

The Utilities have calculated the two-year or variable rate[15] and ten-year capacity and energy rates in the same manner as approved in previous avoided cost proceedings. For ease of comparison, the Public Staff uses the avoided capacity rates and avoided energy rates for QFs interconnected to the distribution system. The rates for QFs interconnecting at the transmission level can be calculated by applying the appropriate adjustment for line losses. The Utilities' proposed changes in avoided energy and capacity rates is best shown by comparing the Utilities' proposed rates with their currently approved annualized rates, which assume QF generation during all on-peak and off-peak energy and capacity hours as identified in their rate schedules.

Duke also provides an "as-available" rate for QFs that do not wish to commit to a two-year or ten-year contract that aligns with FERC Order 872. These rates do not include a capacity component and will be calculated at the end of the month for each hour in a given month with the prices determined based on the incremental cost of production of the next megawatt-hour. QFs will, therefore, be compensated accurately for the price of energy "at the time of delivery," minimizing the risk of overpayment or underpayment. Duke noted in its Joint Initial Statement that FERC Order 872 permits it to pay a long-term fixed capacity rate based upon the avoided

[15] These comments refer to "variable rate" and "two-year rate" interchangeably.

energy cost calculated at the time of delivery, but that it is not implementing this payment option at this time.[16]

While the Utilities' avoided energy rate schedules contain nine different rates dependent on the generation costs throughout the day and season, the *annualized* proposed avoided capacity and avoided energy rates allow for a single avoided energy rate and avoided capacity rate. The following annualized rates assume that a QF operates for all the prescribed on-peak and off-peak hours for both energy and capacity credits and are interconnected at the distribution system level. The Utilities' total annualized ten-year energy rates and capacity rates are shown in **Table 1**, below, which also contains rate comparisons to the rates approved in the Sub 175 Proceeding.

Table 1: 10-year Annualized Energy and Capacity Rates (cents/kWh) and Percent Change from the Sub 175 Proceeding Approved Rates

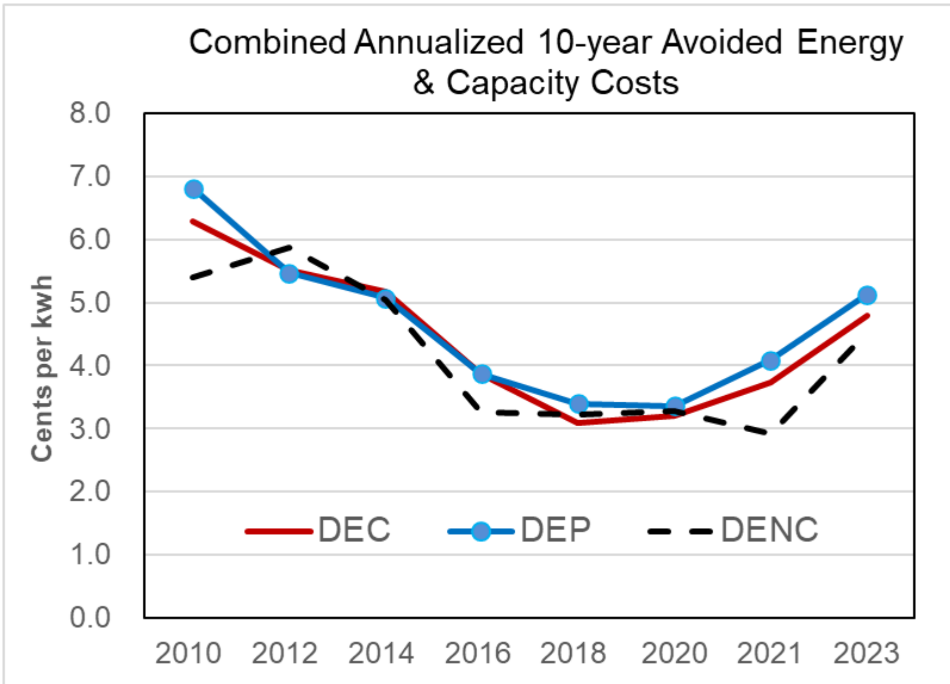
	DEC		DEP		DENC	
	Sub 194 Proposed Rate	% Change	Sub 194 Proposed Rate	% Change	Sub 194 Proposed Rate	% Change
Annualized Energy Rate[17]	4.22	22%	4.08	15%	3.70	45%
Annualized Capacity Rate	0.58	123%	1.05	91%	0.84	127%
Combined Total Rate	4.80	29%	5.13	25%	4.54	56%

[16] Joint Initial Statement, at 33.

[17] The energy rates reflect rates applicable to uncontrolled solar (Duke) and intermittent resources (DENC) connected to the distribution system, and therefore include the SISC (Duke) and Re-Dispatch Charge (DENC).

Figure 2, below, is a graph of the approved combined avoided costs for the Utilities from 2010 through 2021 and the proposed annualized avoided cost rates in this proceeding.

Figure 2: Combined Annualized 10-year Avoided Energy and Capacity Rates (Approved and Proposed)



b. Avoided Cost of Capacity

The Commission's October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 148 (Sub 148 Order) found that avoided capacity value should be recognized beginning with the year that the utility's most recently filed IRP forecast shows a capacity need, consistent with N.C.G.S. § 62-156(b)(3), as amended by House Bill 589.[18] As such, the Utilities' proposed avoided capacity rates provide for the payment of capacity

[18] 2016 Avoided Cost Order, at 10.

costs only when a future capacity need can be avoided. The first year of need is based upon the load forecasts utilized in each Utility's most recently filed IRP (or CPIRP for Duke).

In the Sub 158 Order, the Commission found that it is appropriate for an electric utility to update its avoided capacity calculations to reflect any changes in the utility's first year of avoidable capacity need for negotiated contracts and for use in the CPRE program. In addition, the Commission stated that:

> [b]eginning with the 2020 IRP, the Commission finds that it is appropriate for the Utilities to include a specific statement of undesignated capacity need that is avoidable by QFs in order to remove uncertainty surrounding the exact year of capacity need and to provide a clearer standard for all parties in various regulatory proceedings, especially the next biennial avoided cost proceeding.[19]

The Utilities' CPIRP Update and IRP support that DEC's payments for avoided capacity costs begin in 2025, DEP in 2024, and DENC in 2023.[20] The calculation of avoided capacity rates for each utility reflects the fixed costs of owning a CT beginning in its first year of need for all resources except certain QFs fueled by swine waste and poultry waste, and certain existing hydro power QFs less than 5 MW as discussed more fully below. The General Assembly granted these exceptions in N.C.G.S. § 62-156(b)(3). The Public Staff finds the Utilities' first years of need to be reasonable and based upon the most recently filed Duke CPIRP and DENC IRP.

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[19] 2018 Avoided Cost Order, at 40.

[20] *See* Duke's CPIRP Update, Technical Appendix, at 15-16; DENC 2023 IRP Addendum 5, filed May 1, 2023, in Docket No. E-100, Sub 192. The CPIRP Update resulted in DEC's first year of need accelerating from 2028 to 2025.

i. ***CT Cost Calculations***

The Commission has approved the use of F-frame CT peaker costs as the basis to determine avoided capacity costs in previous proceedings, and the Utilities have continued to use this resource in the instant docket. The projected capital cost for an installed CT is the factor that has the most impact on the avoided capacity rate. In the Sub 140 Order on Inputs, the Commission concluded that:

> [b]ecause the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding … the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.[21]

The Utilities used publicly available information from the EIA specific to Region 16 (SERC Reliability Corporation / Virginia-Carolinas SRVC) to provide the overnight capital cost[22] estimate for a single industrial F-Class CT in simple-cycle configuration on a greenfield (new construction) site as a starting point. The Utilities then evaluated an economy of scale adjustment that takes into consideration common plant items (e.g., land costs, metering station, administration building) that can be allocated to more than a single CT.

The Public Staff agrees with the Utilities' approach in this case on evaluating, calculating, and applying an adjustment to the EIA published data. Simplified, the EIA data utilizes a single CT, while the Utilities model in their IRPs

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[21] *See* the 2014 Avoided Cost Proceeding's *Order on Inputs*, at 48, in Docket No. E-100, Sub 140.

[22] Overnight capital costs are the capital costs assuming the plant could be built "overnight," with no financing costs.

a site comprised of multiple CTs with common or shared plant. The Utilities' approach in this case aligns with IRP planning and typical CT build-out in each of the Utilities' respective generation fleets.

The EIA 2024 Report no longer provides cost estimates for an F-frame CT, but rather utilizes a 419 MW H-class CT.[23] As such, in the Utilities' next biennial avoided cost proceeding, the publicly available EIA estimate will no longer be available for the F-frame CT. The Public Staff strongly supports the continued use of publicly available data for the cost of a CT. If no other publicly available cost data on an F-class CT is available, the Public Staff believes that it would be appropriate in the next avoided cost proceeding to utilize the advanced CT cost estimate from the EIA as the cost basis for avoided capacity, a position the Public Staff has taken in a prior avoided cost proceeding.[24]

In addition, the Public Staff supported the use of an H-class (advanced) CT as the basis for the Demand Side Management/Energy Efficiency (DSM/EE) Mechanism Review largely to align DSM/EE avoided capacity benefits with the CPIRP Proceeding, which does not include F-class CTs as a selectable resource, and to align with Duke's ongoing plans to build H-class CTs at the site of the Marshall generating facility.[25] Complying with the carbon reduction requirements in House Bill 951 will necessitate a significant expansion of variable renewable

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[23] *See* the EIA 2024 Report, at Table 1-2, Case No. 4. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

[24] *See* Initial Comments of the Public Staff in the Sub 175 Proceeding, at 24-25.

[25] *See* DEC Notification of the NCUC of Preliminary Plans to Construct an Electric Generating Facility in Catawba County, NC, Exhibit 1, filed Nov. 1, 2023, in Docket No. E-7, Sub 1297.

energy sources such as wind and solar, and generation flexibility is key. The H-class CTs can provide greater flexibility than the F-class CTs, which has led Duke to focus on H-class CTs in its system planning.

However, the CPIRP Proceeding will not be complete until the end of 2024, and the DSM Mechanism Review will not impact future DSM/EE programs until 2025 at the earliest. The avoided costs in the instant proceeding will be effective for contracts signed between November 2023 through November 2025. This fact, coupled with the recency of the updated EIA cost data, leads the Public Staff to support the use of an F-frame CT in this proceeding.

Table 2, below, includes the Utilities' proposed CT overnight costs ($ per kW) compared to the costs approved in the Sub 175 Proceeding. These costs reflect a 35% overall increase from the published reports identified in the previous Sub 175 Proceeding.

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In addition to increases in the cost of capital, it appears that the technology-specific inflation that occurred from 2022 through 2023 was the predominant factor for increased overnight CT costs. These costs per kW are the single largest component of the Annual Capacity Costs per kW shown in **Table 2**. These costs are then grossed up to account for revenue requirements, allowance for funds used during construction (AFUDC), and a multi-year construction schedule. Both Duke and Dominion rely on EIA's published capital cost per kW for a CT, as approved in prior proceedings.[26] The estimated cost differences are largely due to differences in escalation rates to arrive at current cost estimates.

The second largest factor underlying the avoided capacity costs is the real charge rate, which includes each company's current cost of debt, current capital structure, and allowed rate of return on common equity (ROE). Unlike most regulatory applications, the discount rate is based on a real or inflation adjusted basis. Other factors include depreciation costs, insurance rates, property taxes, and income taxes. Multiplying the installed cost by the real fixed charge rate produces the annual carrying cost of the CT.

Duke's real fixed charge rate reflects its previously approved method of using a weighted overall cost of capital, where the cost of debt and the capital structure as reported in their Commission Form E.S. 1 is combined with the currently approved ROE for each company. **[BEGIN CONFIDENTIAL]** [redacted]

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[26] The use of published overnight capital was first approved in the 2014 Avoided Cost Proceeding.

[27] *See* Docket No. E-2, Sub 1300.

[28] *See* Docket No. E-7, Sub 1214.

[redacted] **[END CONFIDENTIAL] Table 3**, below, shows Duke's approved 2021 and proposed 2023 fixed charge rates and their proposed rates for the Sub 175 Proceeding.

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Similar to the real fixed charge rate methods adopted by Duke, DENC's levelized economic carrying charge rate is calculated over the full book life of the CT and underlies the determination of DENC's avoided capacity rates. The increase in the economic carrying charge includes both a decrease in the discount rate and an increase in DENC's installed cost of capacity relative to the 2020 cost. **Table 4**, below, shows DENC's proposed 2023 economic carrying charge rate compared to the rate approved in the Sub 175 Proceeding. DENC's economic carrying charge rate includes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** discount rate (which is calculated with a weighted average of the North Carolina and Virginia jurisdictional allowed returns on equity), a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** projected construction costs, projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes.

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The Utilities included fixed O&M costs, the primary cost components of which are overhaul costs and staff labor. The remaining costs include minor repairs and administrative costs. **Table 5**, below, shows the Utilities' approved cost rates for fixed O&M per kW approved in the Sub 175 Proceeding, and the proposed approved cost per kW in this proceeding.

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To determine the avoided capacity cost rates for all other QFs, Duke used the combination of the annual CT carrying costs plus fixed O&M and all the adjustments including the impact of the PAF. This calculation produces an annual capacity cost which, when divided by the megawatt rating of the CT, yields a levelized annual capacity cost ($/kW) shown below in **Table 6**.

The below increase in the Company's annual capacity costs per kW is largely a result of the previously discussed increases in EIA's overnight cost per kW.

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ii. Avoided Capacity Rates

The annual capacity costs are levelized by determining the present value of the annual CT capacity costs and multiplying them by a ten-year annuity factor. Using the present values of the future avoided capacity costs, the Utilities generally continued the rate structure introduced and approved in the Sub 175 Proceeding. Duke incorporates allocation factors that attribute 100% of capacity credits to the winter season. In the Sub 175 Proceeding, DEP allocated all of its capacity credits to the winter season while DEC allocated 4% of its capacity credits to the summer season and 96% to the winter season, reflecting the continued shift of loss of load risk to the winter morning hours as demonstrated in the 2023 Astrapé Resource Adequacy Study (2023 Resource Adequacy Study) filed in the CPIRP

Proceeding.[29] The Public Staff finds the seasonal allocation factors proposed in this proceeding to be reasonable.

Table 7, below, provides DEC's proposed ten-year levelized avoided capacity rates during the summer and winter months for QFs connected at distribution.

Table 7: DEC's Schedule PP (NC): 10-year Capacity Rates (distribution only)

	Swine, Poultry, Certain Hydro		All Other Generation	
	Rate	Change	Rate	Change
Summer Months PM	0	-100%	0	-100%
Winter Months AM	21.21	100%	11.27	+216%
Winter Months PM	0	N/A	0	N/A
Annualized	**1.09**	**+43%**	**0.58**	**+123%**

Table 8, below, provides DEP's proposed ten-year levelized capacity rates during the summer and winter months and the percentage change from the Sub 175 Proceeding rates for QFs interconnected at the distribution level.

[29] *See* DEC/DEP Exhibit 8, Section IV. The 2023 Resource Adequacy Study was filed on August 17, 2023, in Docket No. E-100, Sub 190, as Attachment I to the 2023 CPIRP.

Table 8: DEP's Schedule PP (NC): 10-year Capacity Rates (distribution only)

	Swine, Poultry, Certain Hydro		All Other Generation	
	Rate	Change	Rate	Change
Summer Months PM	0	N/A	0	N/A
Winter Months AM	20.39	+95%	20.39	+158%
Winter Months PM	0	N/A	0	N/A
Annualized	**1.05**	**+46%**	**1.05**	**+91%**

The Public Staff has reviewed Duke's capital cost inputs, line losses, seasonal allocations, and other assumptions incorporated in DEC's and DEP's avoided costs and finds them reasonable for the determination of their avoided capacity rates at this time.

Table 9, below, provides DENC's proposed capacity rates and the percent changes from the Sub 175 Proceeding rates for QFs interconnected at the distribution level for fixed rate 10-year contracts.

Table 9: DENC's Schedule 19-FP: 10-year Capacity Rates (distribution only)

	Swine, Poultry, Certain Hydro		All Other Generation	
	Rate	Change	Rate	Change
Summer Month	11.957	+128%	6.487	+131%
Winter Month	10.920	+125%	5.929	+128%
Shoulder Month	2.418	+127%	1.313	+130%
Annualized	**1.546**	**+124%**	**0.839**	**+127%**

DENC does not pay capacity credits to QFs selling power under the variable rate. The avoided capacity rates proposed by DENC are relatively unchanged from the Sub 175 Proceeding.

The Public Staff has reviewed the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates and finds them reasonable for the determination of DENC's avoided capacity rates at this time.

iii. Capacity Rate Seasonal Allocation

Duke allocated the annual avoided capacity cost by season according to the loss of load risk in each hour and month, derived from the 2023 Resource Adequacy Study. This study uses Monte Carlo simulation techniques to perform thousands of hourly simulations using the reliability model SERVM (Strategic Energy and Risk Valuation Model). This model draws different load profiles, weather years, outages, neighbor assistance, and renewable energy outputs to determine the highest risk of load shed. The results of this study indicate that both DEC and DEP have essentially all their loss of load risk in the winter mornings: 100% for DEP and 99% for DEC. Based on these results, both DEC and DEP have allocated all the capacity credits to the winter morning period. The seasonal and hourly distribution of Loss of Load Expectation (LOLE) from the 2023 Resource Adequacy Study for DEC and DEP is shown in **Figure 3 and Figure 4**, respectively. The seasonal allocation of the annual capacity costs is divided by the number of seasonal peak hours, which yields the avoided capacity rates per kilowatt-hour.

Figure 3: DEC's LOLE Hourly Distribution

Season	Hour Ending 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	SUM
Winter	0.6%	0.9%	1.1%	1.3%	2.8%	10%	22%	26%	12%	9.2%	3.3%	0.8%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	1.1%	1.6%	1.4%	1.4%	1.6%	99.0%
Shoulder	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Summer	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 4: DEP's LOLE Hourly Distribution

Season	Hour Ending 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	SUM
Winter	1.4%	2.0%	3.1%	5.5%	10%	16%	20%	17%	9.1%	5.9%	2.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	2.2%	3.2%	1.6%	100.0%
Shoulder	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Summer	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

For weighting capacity value between seasons and calculating avoided capacity rates, DENC allocated CT costs consistent with the Order as follows: 45% summer, 40% winter, and 15% shoulder.

iv. ***Swine, Poultry, and Hydro Avoided Capacity Rates***

In the 2018 Sub 158 Proceeding, the Commission directed that the:

> [u]tilities shall amend their Standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended in House Bill 329 [Session Law 2019-132].[30]

The avoided capacity credits used to calculate avoided cost rates for swine, poultry, and certain hydro QFs begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begin in the first year of a utility's

[30] Sub 158 Order, at 10-11.

capacity need. The Public Staff has reviewed these capacity credits and other assumptions incorporated in Duke's and DENC's proposed rates for swine, poultry, and certain hydro QFs and finds them reasonable for the determination of the Utilities' avoided capacity credits.

c. Avoided Cost of Energy

The avoided cost of energy primarily includes the fuel costs, startup and shutdown costs, and variable operating and maintenance costs that an electric power supplier avoids when purchasing energy from a QF. The Utilities estimate avoided energy costs using a production cost model to analyze marginal system costs with and without a block of "free" QF power. The marginal system costs are the costs necessary to dispatch the next most cost-effective generator available when loads are increasing. The production cost savings attributable to the 100 MW block of "free" QF power represents the system avoided energy costs, which are then allocated to seasons and pricing periods.

i. <u>Duke's Avoided Cost of Energy</u>

In this proceeding, Duke used the Encompass model to estimate marginal avoided energy costs over two- and ten-year periods.[31] Encompass is an hourly chronological model that dispatches generating units in a least-cost manner subject to various constraints such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp

[31] This is the same model used in Duke's CPIRP to perform capacity expansion and detailed production cost modeling.

rates, and minimum run times. The least-cost dispatch is modeled in combination with Duke's energy sales and peak demand forecasts and the resource expansion plan from its 2023 CPIRP, base Portfolio P3, as filed on August 17, 2023, and updated on January 31, 2024. The Public Staff has reviewed the model inputs for the projected operation of Duke's generation units, including the following: variable O&M; price forecasts for delivered natural gas, coal, oil, and uranium; projected prices of sulfur dioxide and nitrous oxide emission allowances; projected MWh generation from renewable energy resources; projected energy purchases; and other inputs.

One significant update to Duke's method from prior avoided cost proceedings is how natural gas forward market price forecasts and fundamental forecasts are blended. In the Sub 175 Proceeding, the Commission approved the use of natural gas forward market prices for no more than eight years before transitioning to fundamental forecasts for the remainder of the planning period.[32] However, in Duke's 2023 CPIRP, it adopted a new method in response to stakeholder input which utilizes five years of forward market prices, followed by three years of blending with fundamental forecasts, before transitioning fully to fundamental forecasts in year nine. The fundamental forecasts are derived from an average of forecasts developed by the EIA and IHS.[33] The Public Staff finds this method reasonable and consistent with the 2023 CPIRP.

[32] 2022 Avoided Cost Order, at 12.

[33] IHS Global insight is an economic forecast produced by IHS Markit, part of S&P Global.

Based on its review, the Public Staff finds that the MW capacities, heat rates, and other inputs that characterize Duke's generation units are reasonably consistent with the 2023 CPIRP. Should the Public Staff make any recommendations to these inputs in the CPIRP Proceeding that are adopted by the Commission, it may be appropriate for Duke to update these inputs in a compliance filing, should those changes be material. In addition, the Public Staff anticipates that Duke will refile its avoided energy rates in this proceeding, taking into account the CPIRP Update.

As to fuel hedging benefits, consistent with the Sub 158 Order, Duke included avoided fuel hedging benefits in avoided energy calculations, based on the Black-Scholes option pricing model using an estimate for gas volatility, risk-free interest rates, and a strike price, which yielded a fuel hedging value of $0.80 per MWh to supplement its avoided energy rates. **Figure 5**, below, displays annualized avoided energy costs, inclusive of the fuel hedging value, projected by Duke. These annual costs serve as the basis for the two-year and ten-year standard offer rates.

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Duke's proposed two-year fixed rate and ten-year levelized energy rates for uncontrolled solar QFs interconnected at the distribution level, along with the proposed annualized rates with the percentage change from the approved rates from the Sub 175 Proceeding, are shown in **Table 10** and **Table 11**, below. These rates are split into nine pricing periods, as approved in the Sub 158 Proceeding.

Table 10: DEC's Schedule PP (NC): Energy Credits

	Variable (Two-Year)		10-year	
	Rate	Change	Rate	Change
Summer Premium Peak	7.40	75%	7.14	81%
Summer PM Peak	4.98	23%	4.64	20%
Summer Off-Peak	3.50	-3%	3.72	10%
Winter Premium Peak	7.83	24%	8.36	45%
Winter AM Peak	4.44	-17%	5.12	8%
Winter PM Peak	5.51	5%	6.26	39%
Winter Off-Peak	3.74	-18%	4.25	12%
Shoulder Peak	4.38	0%	4.64	23%
Shoulder Off-Peak	3.10	3%	3.25	20%
Annualized	**3.99**	**3%**	**4.22**	**22%**

Table 11: DEP's Schedule PP (NC) Energy Credits

	Variable (Two-Year)		10-year	
	Rate	Change	Rate	Change
Summer Premium Peak	7.06	62%	6.92	74%
Summer PM Peak	4.99	26%	4.59	26%
Summer Off Peak	3.41	-3%	3.59	7%
Winter Premium Peak	7.69	11%	8.16	37%
Winter AM Peak	4.27	-13%	5.09	14%
Winter PM Peak	5.39	0%	6.09	24%
Winter Off Peak	3.64	-19%	4.09	2%
Shoulder Peak	4.35	3%	4.66	25%
Shoulder Off Peak	3.02	-7%	3.14	9%
Annualized	**3.87**	**-1%**	**4.08**	**15%**

These energy periods have been largely unchanged since they were approved in the Sub 158 Proceeding, which defined a method to recalculate the energy periods should system load characteristics shift. As described in Duke's Exhibit 8 to its Joint Initial Statement, system load net of solar generation is seeing its peaks shift away from hours with solar generation, and this change since 2018 is causing Duke to request a modification to several pricing periods.

Specifically, DEC and DEP both propose to shift their summer premium peak later into the evening, with DEP also shifting its summer on-peak period to later in the day. Both DEC and DEP are lengthening their winter evening on-peak period and shortening the winter morning on-peak period to focus on earlier hours. A summary of the shift in pricing periods from Duke's Exhibit 8 is presented in **Figures 6** and **7**, respectively. The Public Staff supports these modifications as consistent with the intent of the Sub 158 Proceeding Rate Design Stipulation.

Figure 6: DEC Energy Pricing Periods, 2021 (lower) to 2023 (upper)

DEC Energy Independent Price Blocks (2023)																								
	Summer Premium Peak			Summer On-Peak			Summer Off-Peak		Winter Premium Peak			Winter On-Peak (AM)			Winter On-Peak (PM)			Winter Off-Peak		Shoulder On-Peak			Shoulder Off-Peak	
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)	Off												On					Premium				On		Off
Winter (Dec - Feb)	Off					On	Premium			On	Off							On (PM)						Off
Shoulder (Remaining)	Off						On				Off						On							Off

DEC Energy Independent Price Blocks (2021)																								
	Summer Premium Peak			Summer On-Peak			Summer Off-Peak		Winter Premium Peak			Winter On-Peak (AM)			Winter On-Peak (PM)			Winter Off-Peak		Shoulder On-Peak			Shoulder Off-Peak	
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)	Off												On				Premium				On		Off	
Winter (Dec - Feb)	Off					On	Premium			On	Off							On (PM)					Off	
Shoulder (Remaining)	Off						On				Off						On							Off

Figure 7: DEP Energy Pricing Periods, 2021 (lower) to 2023 (upper)

DEP Energy Independent Price Blocks (2023)																								
	Summer Premium Peak			Summer On-Peak			Summer Off-Peak		Winter Premium Peak			Winter On-Peak (AM)			Winter On-Peak (PM)			Winter Off-Peak		Shoulder On-Peak			Shoulder Off-Peak	
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)	Off														On				Premium				On	
Winter (Dec - Feb)	Off				On		Premium			Off								On (PM)						Off
Shoulder (Remaining)	Off					On				Off								On						Off

DEP Energy Independent Price Blocks (2021)																								
	Summer Premium Peak			Summer On-Peak			Summer Off-Peak		Winter Premium Peak			Winter On-Peak (AM)			Winter On-Peak (PM)			Winter Off-Peak		Shoulder On-Peak			Shoulder Off-Peak	
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)	Off													On			Premium				On	Off		
Winter (Dec - Feb)	Off				On		Premium			On		Off							On (PM)				Off	
Shoulder (Remaining)	Off					On					Off							On						Off

The proposed rates show a significant increase in the summer afternoon and winter morning periods for ten-year contracts with those annualized avoided energy rates increasing significantly for both DEC and DEP. There is little change to the annualized variable (two-year) rate, although in general the summer rates increase and the winter rates decrease. The lack of increase in the variable rates is likely because the Sub 175 Proceeding occurred during a time of extraordinarily high forward market natural gas prices driven by geopolitical supply disruptions. Because of this increase, the Sub 175 variable rates were greater than the ten-year rates, which is unusual.[34] In this proceeding, those supply disruptions are less of a factor, and the relationship between variable and ten-year rates has reverted to the norm (in that the ten-year annualized energy rate is greater than the variable rate).

[34] Typically, the ten-year avoided energy rates are higher than the two-year rates because the 10-year rates take into account escalating natural gas prices captured in the fundamental price forecast.

ii. ***Duke's SISC***

In this proceeding, DEC proposes a SISC of $1.09 per MWh and DEP proposes a SISC of $1.62 per MWh,[35] based upon the Companies' 2023 SISC Study. The 2023 SISC Study built upon the 2021 SISC Study[36] filed in the Sub 175 Proceeding, as well as feedback and recommendations from the Technical Review Committee (TRC), which was ordered by the Commission in the Sub 158 Proceeding.[37] These proposed figures represent a 5% increase in DEC and a 28% decrease in DEP from the SISCs approved in the Sub 175 Proceeding. These charges were calculated based upon 2,738 MW of solar in DEC and 4,392 MW of solar in DEP, which is approximately the amount of solar expected to be interconnected by 2027 (the study year) in Portfolio 3 of Duke's CPIRP.[38]

The changes to the SISC are largely driven by changes to the DEP and DEC systems and incorporation of feedback from the TRC. For example, the amount of energy storage deployed on Duke's systems has increased to 700 MW from 180 MW in the 2021 SISC Study, and DEC has added the flexible Lincoln 17 advanced class CT, both of which will tend to reduce the integration cost of new solar. In the 2023 SISC Study, Duke used feedback from the TRC to model the Joint Dispatch Agreement between DEC and DEP and incorporated energy

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[35] These decrements are reflected in the above tables.

[36] DEC-DEP Joint Exhibit 10 filed on November 1, 2021, in the Sub 175 Proceeding

[37] *See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 93-95 (April 15, 2020), in the Sub 158 Proceeding. The Sub 167 Proceeding did not include an updated SISC Study.

[38] The CPIRP is first able to add economically-selected solar in 2028; solar added in 2027 and earlier represents the Companies' expectations of solar in development. Therefore, the amount of solar in 2027 is consistent across all CPIRP portfolios.

purchases from the Southeastern Energy Exchange Market (SEEM) for the first time,[39] which increases system flexibility by allowing economic trades of excess energy. The Public Staff finds that Duke satisfied the requirements of the Sub 158 Order during the TRC process and incorporated significant feedback from the TRC into the 2023 SISC Study. The Public Staff recommends that the Commission approve DEC's and DEP's proposed SISCs.

Duke has continued to provide a pathway for solar generators to avoid the SISC by reducing their measured volatility,[40] but as previously discussed, no QF has availed itself of the volatility reduction metrics to avoid the SISC yet.

iii. ***DENC's Schedule 19-FP and Schedule 19-LMP Energy Rates***

In its filing, DENC proposes two avoided cost rate schedules: Schedule 19-FP based on the peaker method and Schedule 19-LMP based on Locational Marginal Pricing (LMP). Schedule 19-FP offers QFs fixed levelized avoided energy and avoided capacity payments for variable and ten-year terms.[41] DENC's method for calculating avoided energy costs for Schedule 19-FP is largely consistent with methods employed in the Sub 175 Proceeding, using the PLEXOS production cost model.

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[39] The TRC recommended that the impact from SEEM not be included in the 2022 Avoided Cost rates due to the lack of SEEM operational experience, but that it "should be considered for the future as operational experience in the SEEM becomes available." *See* Exhibit 10 to Duke's Joint Initial Statement in the Sub 175 Proceeding, at III-4.

[40] The criteria and method to avoid the SISC were approved in the Sub 175 Proceeding by the Commission's August 17, 2021 *Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations*.

[41] *See* Initial Statement and Exhibits of Dominion Energy North Carolina, Exhibit DENC-17, filed on November 1, 2023, in Docket No. E-100, Sub 194.

The least-cost dispatch is modeled in combination with DENC's energy sales and peak demand forecasts using its generation expansion plan "B" included in its 2023 IRP. Similar to Duke, DENC incorporated a "without QF" case and a "with QF" case and used the difference in production costs to calculate the avoided energy rates. The Public Staff has reviewed DENC's PLEXOS inputs and believes that the inputs into the model and the output data from the model are consistent with DENC's 2023 IRP and are reasonable for the determination of DENC's avoided energy costs. However, as previously stated, the Public Staff believes DENC should recalculate its avoided energy costs utilizing expansion plan "E" from its 2023 IRP, which is more consistent with Virginia law.

Consistent with the Sub 175 Proceeding, DENC included avoided fuel hedging values in its avoided energy calculations based on the Black-Scholes option pricing model, using an estimate for gas price volatility, a risk-free interest rate, and the strike price, which yielded a net option price of $0.1702 per MMBtu. The hedging benefit was multiplied by the 7.0 MMBtu/MWh heat rate of a natural gas combined cycle unit to yield a hedging value of $1.19/MWh to supplement DENC's avoided energy costs.

DENC's proposed variable and ten-year levelized energy rates for intermittent QFs that are interconnected at the distribution and transmission level, along with the percentage change from the approved rates in the Sub 175 Proceeding, are shown in **Table 12**, below. Due to a continued finding of backflow on the North Carolina substations, it is appropriate that DENC not be required to pay a marginal line loss adder for its transmission and distribution facilities.

Table 12: DENC's Schedule 19-FP: Energy Credits

	Variable		10-year	
	Rate	Change	Rate	Change
Summer – Premium Peak	5.83	36%	4.82	28%
Summer – On Peak	4.51	43%	3.73	36%
Summer – Off Peak	3.06	43%	2.88	37%
Winter – Premium Peak	6.59	30%	5.49	43%
Winter – On Peak (AM)	5.63	29%	4.61	43%
Winter – On Peak (PM)	5.46	26%	4.47	39%
Winter – Off Peak	4.68	40%	4.00	53%
Shoulder On-Peak	3.69	26%	3.00	38%
Shoulder Off-Peak	2.96	43%	2.62	45%
Annualized	**4.25**	**41%**	**3.70**	**45%**

Figure 8 displays annualized avoided energy costs projected by DENC. These costs form the basis for the calculation of variable and ten-year avoided energy rates.

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[END CONFIDENTIAL]

In Docket No. E-100, Sub 106, the Commission approved DENC's LMP method for DENC in addition to the peaker method. The LMP method is based on market clearing prices of power in PJM.

DENC's proposed Schedule 19-LMP energy is based on the hourly PJM Day Ahead LMPs at the nearest PJM-defined nodal location to the QF. To derive the cents per kWh price, the dollars per MWh PJM Dominion Zone Day-Ahead hourly LMPs are divided by ten and then multiplied by the QF's hourly net generation. The Public Staff agrees with DENC's method for calculating avoided cost energy rates but recommends that DENC use the results of its IRP Expansion Plan E as the cost basis for the rates as described above.

iv. ***DENC's Re-Dispatch Charge***

The Re-Dispatch Charge (RDC) provides payment to DENC and its customers for the additional capacity and energy necessary to compensate for the intermittent nature of solar energy and keep the grid stable, similar to Duke's SISC. DENC continues to apply the RDC that was originally approved in the Sub 158 Order. DENC estimates that the RDC associated with intermittent solar and wind generation is 0.365 cents per kWh and is reflected in the above tables. The Public Staff has reviewed DENC's RDC calculation method and finds it to be reasonable for use in this proceeding.

In addition, the Commission has approved DENC's proposed protocol for avoidance of the RDC.[42] The approved protocol allows a QF to reduce the RDC "to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD)."[43] The Public Staff finds the protocol reasonable for this proceeding. As of the filing of DENC's Initial Statement, no QFs in DENC's territory are currently avoiding the RDC. The RDC avoidance protocol is specifically described in Section VI of DENC's schedule 19-FP tariff and requires the use of an ESD to reduce output variability. DENC does not charge an RDC to facilities selling power under the schedule 19-LMP tariff.

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[42] *See* 2020 Avoided Cost Order, at 48.

[43] DENC Initial Statement, at 15.

d. Performance Adjustment Factor

Table 13, below, shows the PAF the Utilities applied to all QFs. Consistent with the agreement reached by the Utilities and the Public Staff in the Sub 175 Proceeding, the Utilities used the WEUOF metric to calculate the PAF. The Utilities used five years of historic generation outage information while taking into consideration maintenance and forced outages that occur in alignment with the peak period months of the respective utility.[44]

Table 13: Utilities' PAFs

Utility	All QFs
DEC	1.05
DEP	1.07
DENC	1.09

The Public Staff supports the PAFs proposed by the Utilities.

e. Line Loss Adjustment

Line losses include energy lost from electrical resistance in power lines and transformers. Energy from the Utilities' generators has higher line losses than energy from distribution-level QFs because it must travel through transmission lines and transmission-to-distribution transformers first before it reaches customers. The Commission has required the Utilities to pay distribution-level QFs a line loss adder to give them credit for the savings they create. However, QF

[44] For Duke, the peak period months are December through February. For DENC, the peak period months are January, February, and June through August.

energy at distribution level has increased over the past several years to the point where some of it is backfeeding onto the transmission system before being consumed by a customer, thus creating higher line losses. In this proceeding, as in prior proceedings, Duke offers line loss adders in its standard offer contracts.

For QFs with a capacity greater than 1 MW that must negotiate avoided cost rates, Duke proposed the following criteria to determine if a line loss adder is appropriate:

> (i) the substation bank that serves the distribution point-of-interconnection has distributed energy resources ("DER") backflow of greater than or equal to 50%; or (ii) the addition of the QF would cause the DER backflow to become greater than or equal to 50%. If these criteria are met, the QF will receive the transmission rates that exclude marginal loss factors for capacity and energy.

Table 14, below, shows Duke's adjustments for marginal on-peak distribution and transmission line losses, which support the line-loss adjustment. At this time, QFs located in Duke's service areas are somewhat geographically concentrated, but over a relatively large area in the southeast part of the state, and the level of backflow into its transmission systems is not enough to offset the avoided cost benefits from reduced line losses for standard offer-eligible QFs.

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[END CONFIDENTIAL]

In the Sub 167 Order, the Commission found that power backflow on substations in DENC's service territory from solar generation on the distribution grid was high enough that avoided line loss benefits associated with distributed generation have been reduced or negated, and it was appropriate that DENC not include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network. DENC has a higher QF generation-to-load ratio in its North Carolina service territory than Duke. DENC applies a negative adjustment to its avoided energy rates that reflects the lower LMPs in its North Carolina service territory relative to the DOM Zone in PJM. DENC proposes a nine percent average reduction to its avoided energy rates, with each pricing period assigned an individual reduction that is proportional to the gap between the North Carolina LMP and the DOM Zone LMP.[45]

The Public Staff finds that Duke's line loss adjustment factors shown in **Table 14** are consistent with previous avoided cost proceedings and recommends that the Commission approve them. Given the continued increased backflow on DENC's transformers, the Public Staff agrees that a negative adjustment for LMP price differentials is appropriate and should be approved.

[45] *See* Table 1 of DENC's Joint Initial Statement.

IV. WCU's and NRLP's Proposed Rates

WCU and NRLP filed an application for avoided cost rates jointly because they have the same wholesale supplier of energy and capacity, Carolina Power Partners (CCP), and they base their avoided costs upon CCP's costs. In this proceeding, NRLP included the avoided cost options: Schedule PPR for the sellers of solar photovoltaic energy and Schedule NBR for net metering that the Commission approved on October 16, 2023, in its Order Accepting Stipulation, Granting Partial Rate Increase, and Requiring Public Notice in Docket No. E-34, Subs 54 and 55.

CPP charges WCU and NRLP a wholesale rate that varies every year; therefore, WCU and NRLP set avoided cost rates based on formulas as shown in their Exhibits 1 through 3. WCU currently has three solar energy suppliers, with one to be interconnected soon. NRLP has 24 solar energy suppliers and one wind energy supplier.

The Public Staff does not object to WCU's and NRLP's proposed rate formulas in this proceeding.

V. Review of Modifications to Tariffs and to Terms and Conditions

Duke

DEC and DEP have made the following modifications to their tariffs and their terms and conditions:

1. Minor revisions to Schedule PP
2. Replaced the term "Marginal Cost Rate" with "As-Available Rate"

3. Replaced the term “Variable Rate” with “Two-Year Fixed Rate”
4. Minor revisions to their Standard Offer PPAs as shown in DEC’s and DEP’s Exhibit 3
5. Minor revisions to their Terms and Conditions as shown in DEC’s and DEP’s Exhibit 4
6. Minor revisions to their Notice of Commitment forms for QFs up to 1 MW as shown in DEC’s and DEP’s Exhibit 6
7. Minor revisions to their Notice of Commitment forms for QFs greater than 1 MW as shown in DEC’s and DEP’s Exhibit 7

DENC

DENC is not proposing any changes to its standard offer contracts for QFs up to 1 MW or its Legally Enforceable Obligation forms, which are similar to DEC’s and DEP’s Notice of Commitment forms.

The only change that DENC made to its PPA contracts for Schedule 19-FP rates and Schedule 19-LMP rates is updating the docket numbers to the current proceeding.

VI. Conclusions and Recommendations

In summary, the Public Staff recommends that the Commission:

(1) approve Duke’s avoided energy and capacity rate methods using Portfolio P3 Fall Base from the 2023 CPIRP Update, subject to the other recommendations below;

(2) direct DENC to use its generation IRP Expansion Plan E production cost models as the cost basis to calculate its avoided energy rates in this proceeding;

(3) allow Duke's rates for ESS Retrofits in the 2022 Avoided Cost Order to expire and be discontinued;

(4) require the Utilities, in the next avoided cost proceeding, to calculate avoided capacity payments, at least as an alternative, based upon advanced class CTs ;

(5) require the PAF for hydroelectric QFs be the same as other QFs;

(6) find the Utilities' first years of need to be reasonable;

(7) approve DEC's and DEP's proposal to shift their summer premium peaks later into the evening, with DEP also shifting its summer on-peak period to later in the day, and their lengthening of the winter evening on-peak period and shortening the winter morning on-peak period to focus on earlier hours;

(8) approve DENC's avoided capacity rates;

(9) approve the PAFs proposed by the Utilities;

(10) approve the updated NEEC proposed by Duke;

(11) direct Duke and DENC to address the inclusion of solar generator outage data in the calculation of the PAF in their next avoided cost filings, including the current status of outage reporting requirements set by NERC;

(12) direct Duke to 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 Duke's service territories in its future avoided cost filings;

(13) direct Duke to specifically address QFs seeking SISC avoidance 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;

(14) approve DEC's and DEP's proposed SISC;

(15) approve DENC's RDC avoidance protocol;

(16) direct DENC to file a report on the types of forecasts and the ESD dispatch behavior for QFs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of QFs, in DENC's service territory in its future avoided cost filings;

(17) direct DENC to specifically address QFs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the RDC;

(18) approve DEC's and DEP's line loss adjustment factors; and

(19) approve both Duke's proposed revisions to its NOC and DENC's proposed revisions to its LEO Forms;

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

Respectfully submitted this the 21st day of February, 2024.

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DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please describe any future plans of Duke Energy to test the ability of inverter-based resources to provide ancillary services.

Response:

The following quote is referencing page 17 of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Inverter Based Resources Testing Report filed on August 1, 2023 in Docket No. E-100, Sub 175:

"Based on the short timeline (January – June 2023) to design and conduct the testing , additional testing with different, larger Duke-owned IBR resource types (standalone batteries and solar plus storage) could allow for design of the testing with plans to record more parameters for post testing data analytics to thoroughly evaluate the capabilities of IBRs to provide certain ancillary services. Additional testing would also allow for assessing the costs for the testing and the IBR design/modifications needed to provide the ancillary service. Duke Energy believes that further study and testing of different Dukeowned IBR resource types such as standalone batteries and solar plus storage, (resource types that will be significant in the future resource mix), will help determine whether a pilot program would be worthwhile."

The Companes continue to believe that the best course of action is further study and testing of different Duke-owned IBR resource types such as utility-scale, transmission connected standalone batteries and solar plus storage, resource types that will be significant in volume in the future resource mix as evidenced in the August 2023 resource plan filings. This future testing of different resource types will help determine whether a pilot program would be worthwhile.

Also as stated in the report in the Conclusions section on page 17, Reactive power management/voltage support is a service based on locational needs. This service has been provided successfully by transmission connected solar following a voltage schedule within power factor limits for several years now and will continue to be utilized from transmission connected IBRs in the future to some degree as the locational need is determined by Transmission Planners. The commissioning and monitoring of the IBR controllers will be extremely important for ensuring this reactive power management/voltage support will be provided to the system when needed.

Responder: Sammy Roberts, GM Transmission Planning and Operations Strategy

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please describe any other studies known by Duke Energy regarding the ability of inverter-based resources to provide ancillary services.

Response:

The only other US-based utility-scale PV ancillary service documented testing known by Duke Energy at this time was conducted by NREL and CAISO in cooperation with First Solar's 300 MW Desert Stateline Solar Facility located near the California – Nevada state line in CAISO. As stated by Duke Energy in Public Service Commission of South Carolina Docket No. 2019-185-E and No. 2019-186-E, Rebuttal Testimony of John Samuel Holeman III on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, even with the seemingly perfect blue-sky weather for forecasting the capability of this solar facility to provide a regulation and load following service, this facility solar output was interrupted for two short periods with the passage of a couple of clouds; the first instance shows the solar output dropped by 60 MW in approximately 1 minute and the second instance shows the output dropped by at least 160 MW in approximately 2 minutes. During these periods, this testing demonstrated the operational uncertainty of this very large 300 MW solar PV plant dropping160 MW in output in an unscheduled manner over a two-minute period under seemingly optimal weather conditions. As demonstrated with the testing of the Duke-owned IBR solar resources, unlike the weather that is experienced by the 300MW First Solar Desert Stateline solar facility, cloud cover is a frequent occurrence in the Carolinas and thus the conclusion that while some IBRs are suitable for providing regulation, maintaining a regulation range with standalone solar on partly cloudy to mostly cloudy days is infeasible. A link to the NREL/First Solar Test Report is available here: https://www.nrel.gov/docs/fy17osti/67799.pdf

Responder: Sammy Roberts, GM Transmission Planning and Operations Strategy

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Regarding the Invertor Based Resources Test Report filed by Duke Energy on August 1, 2023, in Docket No. E-100, Sub 175, please provide Duke Energy's conclusions regarding the Asheville Rock Hill battery.

Response:

Transmission-connected battery systems properly designed and procured with specific warranty parameters and with T-SCADA control and communication systems designed in the right way and coordinated with other regulation resources and system needs can provide regulation service or follow setpoints from a unit commitment generated energy arbitrage profile within the design capabilities of the battery system. Distribution connected resources have more intensive design coordination (e.g., coordination with voltage control resources, station loading, self-healing schemes, power quality considerations for customers) in order to enable the resource to provide ancillary services.

Responder: Sammy Roberts, GM Transmission Planning and Operations Strategy

CERTIFICATE OF SERVICE

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

This the 21st day of February, 2024.

Electronically submitted
/s/ Robert B. Josey