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May 20, 2024

VIA ELECTRONIG FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: *Separate Proposed Order of Dominion Energy North Carolina*
Docket No. E-100, Sub 194

Dear Ms. Dunston:

Enclosed for filing in the above-referenced proceeding on behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("Company") is the Company's *Separate Proposed Order*, which addresses Findings of Fact Nos. 9 and 10 from the Joint Proposed Order filed on behalf of the Company and the Public Staff contemporaneously in this docket.

Thank you for your assistance with this matter. Feel free to contact me with any questions about this filing.

Sincerely,

/s/Andrea R. Kells

ARK:sbc

Enclosure

cc: Lauren W. Biskie

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 194

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2023	)))))	SEPARATE PROPOSED ORDER OF DOMINION ENERGY NORTH CAROLINA

BY THE COMMISSION: This is the 2023 biennial proceeding held by the North Carolina Utilities Commission (Commission) pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. § 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegate responsibilities in that regard to this Commission. This proceeding is also held pursuant to N.C.G.S. § 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers, as defined in N.C. Gen. Stat. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC prescribe the responsibilities of FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires FERC to adopt such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. In adopting such rules, FERC stated:

> Under Section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards, and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities [QFs], and thus become eligible for the rates and exemptions set forth under Section 210 of PURPA.

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (cross-referenced 10 FERC ¶ 61,150), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state regulation, FERC delegated the implementation of these rules to the state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings as required by N.C.G.S. § 62-156. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

As noted above, this proceeding also results from the mandate of N.C.G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The General Assembly amended N.C.G.S. § 62-156 in 2017 through enactment of Session Law 2017-192 (House Bill 589) and again in 2019 through enactment of Session Law 2019-132 (House Bill 329).

On August 7, 2023, the Commission issued in this docket an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing (2023 Scheduling Order). Pursuant to the 2023 Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke Energy), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC, and together with DEC and DEP, the Utilities), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Light and Power Company (New River) were made parties to the proceeding.

The 2023 Scheduling Order stated that given the recurring nature of the issues and decisions that have traditionally arisen in these proceedings, the

Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules rather than a full evidentiary hearing. The Commission established February 7, 2024, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings; as the deadline for reply comments; and the deadlines for additional comments, additional reply comments and proposed orders to be established by further order of the Commission. The 2023 Scheduling Order also scheduled a public hearing for February 6, 2024, solely for the purpose of taking non-expert public witness testimony. Finally, the 2023 Scheduling Order required the Utilities to publish notice in newspapers having general circulation in their respective North Carolina service areas and submit affidavits of publication to the Commission no later than the date of the hearing.

The following parties filed timely petitions to intervene that the Commission granted: the North Carolina Attorney General's Office (AGO), the North Carolina Sustainable Energy Association (NCSEA), the Carolina's Clean Energy Business Alliance (CCEBA), the Southern Alliance for Clean Energy (SACE), and the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR). Participation of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On November 1, 2023, pursuant to the 2023 Scheduling Order DENC filed its Initial Statement and Exhibits (DENC Initial Statement), along with DENC's avoided cost information as required by 18 C.F.R § 292.302(b)(1)-(3).

On November 1, 2023, WCU and New River filed their Joint Comments and Proposed Rates.

On January 9, 2024, DENC filed a letter providing the Commission and the parties a status update regarding Virginia's withdrawal from the Regional Greenhouse Gas Initiative (RGGI).

On January 30, 2024, NCSEA, CCEBA, and SACE filed a Joint Motion for Extension of Time through and including February 21, 2024, for the parties to file their initial comments and through and including March 27, 2024, for parties to file their reply comments, which was granted by Commission order issued on February 6, 2024.

On January 22, 2024, DENC filed Proof of Publication of the notice of hearing. On February 5, 2024, Duke Energy filed affidavits of publication of notice.

On February 6, 2024, the public witness hearing portion of the proceeding was held as scheduled, and no witnesses appeared to testify.

On February 21, 2024, the Public Staff, AGO, SACE, CCEBA, and NCSEA filed Initial Comments.

On March 27, 2024, reply comments were filed by DENC, Duke Energy, the Public Staff, NCSEA, SACE, and CCEBA.

On April 10, 2024, the Commission issued its Order Requiring the Filing of Proposed Orders and Briefs, determining that a full evidentiary hearing was not required.

On May 7, 2024, the Commission issued its Order Granting Motion for Extension of Time filed jointly by Duke Energy and the Public Staff and ordering that all parties may file proposed orders or briefs in this proceeding on or before May 20, 2024.

On May 20, 2024, proposed orders and briefs were filed by the parties.

Based on the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DENC to offer long-term levelized capacity rates and energy rates for ten-year periods as a standard option to all QFs contracting to sell one MW or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration.

2. It is appropriate for the Utilities to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate

option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding.

3. DENC should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the peaker methodology, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (Sub 106 Order), except as modified by the Commission in its October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148 (Sub 148 Order).

4. It is reasonable and appropriate for the Utilities to continue using the peaker methodology to calculate the avoided capacity cost rates for purposes of this proceeding, and to base that calculation on a combustion turbine (CT).

5. The Utilities should consider, and evaluate, alternative capacity resources such as advanced class CTs in the next biennial proceeding.

6. DENC's proposed installed cost of a CT is appropriate for use in calculating avoided cost capacity costs in this proceeding.

7. DENC has appropriately identified in its 2023 Integrated Resource Plan (2023 IRP) its first avoidable capacity need as occurring in 2024-33 and relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

8. It is reasonable and appropriate for DENC to use a 5-year average Weighted Equivalent Unforced Outage Factor (WEUOF) to determine the Performance Adjustment Factor (PAF) in its avoided cost calculations for all QFs. DENC's calculation of a PAF of 1.09 for this proceeding is reasonable and appropriate.

9. It is reasonable and appropriate for DENC to use Alternative Plan B from its 2023 IRP as the basis for the development of avoided energy costs under Schedule 19-FP for purposes of this proceeding.

10. DENC's proposal to charge $3.65/MWh to recover costs incurred to integrate intermittent, non-dispatchable QFs in its service territory is reasonable and appropriate for purposes of this proceeding.

11. DENC's proposed non-IRP input assumptions to be used in determining its proposed avoided energy rate are appropriate for use in this proceeding.

12. It is reasonable and appropriate for DENC to continue not to include a line loss adder in its standard offer avoided cost payments to solar QFs on its distribution network.

13. It is reasonable and appropriate for DENC to maintain its proposed re-dispatch charge (RDC) avoidance protocol as approved in the Sub 175 Order.

14. DENC's proposal to continue to use the energy and capacity rate design approved in the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 175 Order) issued on November 22, 2022, in Docket No. E-100, Sub 175 (Sub 175 proceeding) is reasonable and appropriate for purposes of this proceeding.

15. DENC's proposal to continue to use seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons that were approved in the Sub 175 Order is reasonable and appropriate for purposes of this proceeding.

16. It is reasonable and appropriate for DENC to continue using Retrofit Storage Legally Enforceable Obligation (LEO) Forms as approved in the Sub 175 Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in DENC's Initial Statement and Reply Comments and the Initial Statement of the Public Staff.

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC used the PLEXOS model for the calculation and used its generation expansion plan "B" from its most recent 2023 IRP filed on May 1, 2023, in Docket No. E-100, Sub 192 as the starting point for its analysis as the "without QF case." DENC ran a second PLEXOS case, the "with QF" case, with an additional QF resource. DENC explains that the input assumptions in this modeling process falls into three categories: (1) assumptions regarding generating unit operating characteristics, (2) purchase power assumptions and non-utility generator sources, and (3) the variable (or dispatch) costs of generating units (including fuel, variable O&M, and emission and start-up costs). With these inputs, the resulting PLEXOS output was used to calculate the levelized long-term fixed energy rates under Schedule 19-FP for each of the nine pricing periods approved in the Sub 175 Order. (DENC Initial Statement at 5-6.)

The Public Staff notes that DENC calculated its proposed avoided energy rates using its generation expansion Plan B from its 2023 IRP in Docket No. E-100, Sub 192. The Public Staff asserts that Plan B is a least-cost plan that only partially complies with all applicable state law, including the Virginia Clean Economy Act

(VCEA) and that Plan E is the least-cost plan that complies with the VCEA. The Public Staff referenced its recommendation in Docket No. E-100, Sub 192 that the Commission not approve any of DENC's IRP plans and instead, find DENC's short term action plan reasonable for planning purposes. (Public Staff Initial Statement at 9-10). The Public Staff concludes that therefore it is appropriate for DENC to utilize generation expansion Plan E for calculating DENC's avoided energy rates in this proceeding. (Id. at 10.)

In its Reply Comments, DENC responds that it continues to support Alternative Plan B as the basis for calculating avoided energy rates proposed for Schedule 19-FP in this proceeding and that it would not be appropriate to base the energy rates on Plan E for several reasons. DENC explains that it provided Plans B and D in its 2023 IRP to show two alternatives to meeting customer demand while meeting the VCEA development targets. Specifically, the VCEA development targets for solar and storage resources and offshore wind are included in the PLEXOS model for both Plans B and D in order to ensure compliance with those requirements. The difference between Plans B and D was in the modeling of unit retirements, with Plan B allowing the model to select unit retirement years on a least-cost optimized basis (in which case the model did not retire any units) and Plan D determining retirement years by retiring all carbon-emitting units between 2039 and 2045, consistent with the VCEA's 2045 target date. DENC clarifies that while thermal generators were not retired under Plan B, the VCEA allows such generators to remain online if their retirement would threaten electric service reliability. DENC concludes that Plan B represents a plausible VCEA compliant pathway if DENC's thermal units are not retired because they would be needed to ensure system reliability. DENC notes in addition that for the 10-year avoided cost period that is relevant to this proceeding, Plans B and D have the same build out and retirement projects. DENC emphasizes that neither of the Alternative Plans retires any thermal generators during the 2024-2033 time period and their retirement assumption differences after 2033 are not relevant for purposes of this proceeding.

DENC explains further that it developed Plans C and E to comply with a stipulation obligation entered into in a Virginia State Corporation Commission proceeding, and that consistent with that stipulation, those plans least-cost optimize annual additions of new resources to meet DENC's need for capacity, energy, and RECs without regard to the VCEA's development targets. Additionally, Plan C unit retirement dates match those of Plan B, and Plan E unit retirement dates match those of Plan D. In summary, DENC states that Plans C and E are timing- and cost-optimized versions of Plans B and D, respectively.

DENC concludes that Plan B complies with the VCEA and does not differ from Plan E with regards to thermal resource retirements over the 2024-2033 period used to determine avoided costs in this proceeding. DENC adds that Plan B is well-studied, making it more reasonable for use in determining avoided cost rates compared to Plan E, which was designed as a sensitivity to Plan D. (DENC Reply Comments at 3-7).

Discussion and Conclusions

Based on the entire record, the Commission finds that DENC appropriately based its calculation of avoided energy rates for Schedule 19-FP in this proceeding on Alternative Plan B from its 2023 IRP. DENC presented evidence showing that Plan B is well-studied and compliant with the VCEA. First, Plan B meets the VCEA development targets. Moreover, while Plan B's modeling of unit retirements was conducted on a least-cost basis, this result is consistent with the VCEA's provision for thermal generators to remain online beyond 2045 if their retirement would threaten electric service reliability. Alternatively, it can be considered that Plan D does retire all thermal generators by 2045 (according to the same schedule as Plan E) and that, for the 10-year avoided cost period that is relevant to this proceeding, Plan B's build out and retirement projects do not differ from Plan D (they are effectively the same). Plan E, on the contrary, was modeled as a sensitivity to other alternative Plans without regard to the development targets of the Virginia law.

The Commission notes in addition that as addressed further in the discussion and conclusions for Finding of Fact No. 10, for the 2023 IRP, DENC modeled the re-dispatch cost by utilizing the Alternative Plan build plan from the 2023 IRP and studying select years chosen based on when resources were introduced or retired in the Alternative Plan B build plan. Utilizing Plan B as the starting point for the calculation of avoided energy costs for Schedule 19-FP is therefore consistent with DENC's modeling of the RDC, which represents an adder to those costs for the determination of Schedule 19-FP avoided energy rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is found in DENC's Initial Statement and the Initial Statement of the Public Staff.

Summary of the Evidence

In its Initial Statement, DENC explains that in the Sub 158 Avoided Cost Case, it proposed to adjust avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs—specifically, re-dispatch costs—caused by these generators, and that the Commission approved the proposed RDC, modified pursuant to DENC's agreement with the Public Staff, to be $0.78/MWh. In the Sub 167 Avoided Cost Case, the Commission approved DENC's proposal to continue to apply the $0.78/MWh RDC that was approved in the Sub 158 Order for purposes of Schedule 19-FP. (DENC Initial Statement at 12.) In the Sub 175 proceeding, DENC updated its proposed re-dispatch charge, which the Commission approved in the Sub 175 Order, finding the updated methodology to be an improvement from the one used previously. (Id.)

For this proceeding, DENC proposes an update to the RDC to accurately reflect its costs of the integration of intermittent, non-dispatchable QFs on its system using the same methodology that DENC used and the Commission approved in the Sub 175 proceeding. (DENC Initial Statement at 12). DENC states that as was the case in the Sub 175 proceeding, for the 2023 IRP, DENC took a chronological approach to modeling the re-dispatch cost, by utilizing one build plan from the 2023 IRP (Alternative Plan B) and studying select years chosen based on when resources were introduced or retired in the 2023 IRP Alternative Plan B build plan. For each simulation year, DENC performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations but applied different hourly renewable profiles from NREL's historical weather patterns studies to reoptimize the system cost. For the 2023 re-dispatch analysis, the Company added onshore wind stochastics to the model and, because impacts to the DOM Zone were de minimis, discontinued modeling ISO New England and the New York ISO. (Id. at 13). DENC states that the total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel, variable operation and maintenance costs, emissions, and purchase/sale of energy and power costs. The re-dispatch cost is the delta of the system cost divided by DENC's expected total renewable generation. Based on these results, DENC constructed a generation re-dispatch cost curve for the entire Study Period reflected in the 2023 IRP. DENC calculated the average RDC for the ten years 2024-2033 to be $3.65/MWh and proposes to use this value to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP. (DENC Initial Statement at 13-14.)

In its initial statement, the Public Staff reports that it has reviewed DENC's RDC calculation method and finds it reasonable for use in this proceeding. (Public Staff Initial Statement at 45).

No party filed reply comments on DENC's proposed RDC.

Discussion and Conclusions

Based upon the foregoing and the entire record, the Commission finds that DENC's updated re-dispatch cost is reasonable and appropriate for purposes of this proceeding. The Public Staff reviewed DENC's RDC calculation method and found it reasonable for use in this proceeding. No other party disputed DENC's proposed RDC. The RDC analysis conducted by the Company represents a significant and well-studied effort, including over 200 simulations, for multiple years and hourly renewable profiles and no evidence has been presented to contradict the reasonableness of DENC's RDC analysis or suggest an alternative. The Commission notes moreover that the RDC is based on the build plan contained in DENC's Alternative Plan B from its 2023 IRP, which is appropriately consistent with DENC's use of Alternative Plan B as the basis for DENC's avoided energy rates. The Commission therefore concludes that it is appropriate for DENC to apply an RDC of $3.65/MWh for purposes of Schedule 19-FP in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That DENC's Alternative Plan B shall be used to calculate DENC's avoided energy rates under Schedule 19-FP in this proceeding.

2. That DENC shall use a re-dispatch charge of $3.65/MWh in calculating DENC's rates in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _______________, 2024.

NORTH CAROLINA UTILITIES COMMISSION

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Separate Proposed Order, as filed in Docket No. E-100, Sub 194, was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 20th day of May, 2024.

/s/Andrea R. Kells
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