STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

BY THE COMMISSION: This is the 2021 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. § 824a-3, and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegate responsibilities in that regard to this Commission. This proceeding is also held pursuant to N.C. Gen. Stat. § 62-156, which requires this Commission to determine the rates to be paid by electric public 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 thereto 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).

Section 210 of PURPA requires each electric utility to offer to purchase available electric energy from cogeneration and small power production facilities that obtain qualifying facility (QF) status. For such purchases, electric utilities must 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 by 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 state regulatory authorities. State commissions may implement these rules by issuing regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to FERC's rules. This Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings in conjunction with the process required by N.C.G.S. § 62-156. The instant proceeding is the latest such proceeding this Commission has held since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates electric utilities subject to the Commission's jurisdiction would pay to the QFs with which 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 the General Assembly enacted 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 public 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 (HB 589) and again in 2019 through enactment of Session Law 2019-132 (HB 329).

On April 15, 2020, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 158 (Sub 158 Order), in which it also posed a series of additional issues (Sub 158 Additional Issues) for the utilities involved in that docket to address in future proceedings.[1]

On August 13, 2020, in Docket No. E-100, Sub 167, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing establishing the 2020 Biennial Proceeding. In that order, the Commission made Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (collectively, Duke), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DENC), Western Carolina University (WCU), and Appalachian State University d/b/a New River

[1] The utilities involved in Docket No. E-100, Sub 158 included Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, Western Carolina University, and Appalachian State University d/b/a New River Light and Power Company.

Light and Power Company (New River) (collectively, the Utilities) parties to the proceeding.

On October 20, 2020, DEC, DEP, and DENC filed a Notification of Intended Compliance with N.C.G.S. § 62-156(b), a Request for Continuance of Compliance with Certain 2020 Filing Requirements, and a Request to Prospectively Modify Timing of Biennial Proceedings notifying the Commission of their intent to file streamlined 2020 avoided cost filings that would update the inputs in their avoided energy rates and avoided capacity rates based on the methodological guidelines and requirements the Commission approved in its Sub 158 Order and requesting that the Commission delay until November 2021 the more comprehensive filings that would address the Sub 158 Additional Issues. DEC, DEP, and DENC also proposed that, going forward, the Commission modify the timing of biennial avoided cost proceedings by starting the next full biennial proceeding in 2021 and shifting all future proceedings to odd calendar years.

On October 30, 2020, the Commission granted the continuance and directed DEC, DEP, and DENC to: (1) address the Sub 158 Additional Issues by November 2, 2021; (2) file a list of the Sub 158 Additional Issues and a timeline for how they intended to address those issues by December 7, 2020; and (3) file updates on their progress on the Sub 158 Additional Issues at least every 45 days after the December 7, 2020 filing.

On August 13, 2021, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 167 (Sub 167 Order). In the Sub 167 Order, the Commission determined that DEC, DEP, and DENC had complied with the requirements of the 2018 Sub 158 Order in filing their updates on the Sub 158 Additional Issues, and the Commission directed DEC, DEP, and DENC to continue filing updates on the Sub 158 Additional Issues until the issues were fully addressed or until the filing of proposed rates and terms on November 1, 2021, whichever was earlier and, to the extent relevant to each respective utility, address the Sub 158 Additional Issues in its November 2021 filing.

Also on August 13, 2021, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing (2021 Scheduling Order). In the 2021 Scheduling Order, the Commission made Duke, DENC, WCU, and New River (collectively, the Utilities) parties to the proceeding. The 2021 Scheduling Order stated that 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 9, 2022, as the deadline for interventions by interested persons and for initial comments and exhibits on the Utilities' filings, and March 11, 2022, as the deadline for reply comments. The 2021 Scheduling Order also scheduled a public hearing for February 22, 2022, solely for the purpose of taking non-expert public witness testimony. Finally, the 2021 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 no later than the date of the hearing.

The following parties filed timely petitions to intervene that the Commission granted: the North Carolina Sustainable Energy Association (NCSEA); the Carolinas Clean Energy Business Alliance (CCEBA); the Carolina Industrial Customers for Fair Utility Rates I, II, and III (CIGFUR); Southern Alliance for Clean Energy (SACE); and Appalachian Voices. Participation of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On November 1, 2021, pursuant to the 2021 Scheduling Order, Duke and DENC filed their proposed avoided cost rates, standard power purchase agreements (PPAs), and terms and conditions. On December 21, 2021, WCU and New River jointly made their avoided cost filings in this docket.

On February 24, 2022, the Public Staff, SACE, and Appalachian Voices filed comments. On the same date, CCEBA and NCSEA filed Joint Initial Comments.

On March 1, 2022, New River filed amended proposed rates and contracts. On March 11, 2022, Appalachian Voices filed a response to New River's amended filing.

On March 31, 2022, SACE filed its Reply Comments. The following day, New River, NCSEA, Duke, DENC, and the Public Staff each filed Reply Comments. On the same date, CCEBA and NCSEA filed Joint Reply Comments.

On May 16, 2022, the Commission issued its Order Requiring the Filing of Proposed Orders and Briefs, determining that a full evidentiary hearing was not required.

Based upon the foregoing and the entire record herein, the Commission now makes the following:

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DENC to offer long-term levelized capacity payments and energy payments for ten-year periods as a standard option to all QFs contracting to sell one megawatt (MW) or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option subject to renewal 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 DEC, DEP, and DENC 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 by: (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 as-available energy rate, including either the Marginal Cost Rate or the 2-year contractual Variable Rate. If the utility does not have a competitive bidding 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 parties choose the Marginal Cost Rate option, they may not lock in such rate by a contract term; instead, the rate shall change as the Commission determines 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 the Commission approved in its 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 the Commission modified them 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. The quantification by DEC, DEP, and DENC of their respective avoided capacity costs using the peaker methodology and their resulting avoided capacity rates is reasonable.

5. DEC’s and DEP’s hypothetical avoided combustion turbine (CT) costs for a single F-Class CT constructed at a greenfield site, adjusted to reflect economies of scale are reasonable, based on publicly available United States Energy Information Administration (EIA) data, and appropriate for use in calculating avoided capacity costs in this proceeding.

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

7. DEC’s and DEP’s respective first years of avoidable capacity need are appropriate and are consistent with the 2021 Sub 167 Order and DEC’s and DEP’s 2020 Integrated Resource Plans (IRPs), with updated assumptions to reflect the Commission’s March 31, 2021 Order in Docket No. E-7, Sub 1214 approving DEC’s Integrated Volt/Var Control program.

8. DENC has appropriately identified in its 2021 Integrated Resource Plan Update (IRP Update) its first avoidable capacity need as occurring in 2026, and relied on that identified first avoidable capacity need to determine the first year of avoidable capacity need for purposes of this proceeding.

9. DEC, DEP, and DENC have also appropriately included in their standard offer schedules provisions recognizing that, in certain circumstances, QFs fueled by swine waste, poultry waste, and hydropower less than 5 MW receive capacity payments calculated without incorporating the demonstrated first year of need for future capacity as reflected in their respective IRPs.

10. It is appropriate to require DEC and DEP to continue to utilize a performance adjustment factor (PAF) of 2.0 for run-of-river hydroelectric QFs, and a PAF of 1.04 in their respective avoided cost calculations for all other QFs.

11. 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 calculation for all QFs. DENC's calculation of a PAF of 1.07 for this proceeding is reasonable and appropriate.

12. It is appropriate in this proceeding to require DEC and DEP to continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period.

13. DEC's and DEP's use of their respective 2020 IRP natural gas transportation and pricing assumptions are reasonable for purposes of calculating avoided costs in this proceeding.

14. DEC's and DEP's fuel hedging adjustment is reasonable and appropriate for purposes of this proceeding.

15. DENC's proposed input assumptions to be used in determining its avoided energy cost related to fuel forecasting, fuel hedging activities, and the locational marginal price (LMP) adjustment, are appropriate for use in this proceeding.

16. DEC's and DEP's calculation of avoided energy rates, using inputs from their 2020 IRPs, is appropriate for this proceeding.

17. DEC's and DEP's proposed distribution line loss adder included in their standard offer Schedule PPs is appropriate for distribution-interconnected QFs in the DEC and DEP service territories.

18. For QFs greater than 1 MW, DEC's and DEP's proposal to assess, on a case by case basis, the individual characteristics of the QF and address through

negotiation of the PPA whether retaining or eliminating the line loss adjustment from the avoided energy value on a case-by-case basis is reasonable and appropriate.

19. 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.

20. DEC's and DEP's solar integration decrements of $1.05 per MWh for DEC and $2.26 per MWh for DEP, based on the analysis in the 2021 Solar Integration Services Charge Study prepared by Astrapé Consulting which incorporated the findings in the independent technical report of the Technical Review Committee, are reasonable and appropriate for purposes of this proceeding.

21. DEC's and DEP's proposed solar integration services charge (SISC) avoidance protocols and process are appropriate and in compliance with the Commission's Sub 158 SISC Avoidance Order.

22. DENC's proposal to charge $1.87/MWh to recover costs incurred to integrate intermittent, non-dispatchable QFs in its service territory is reasonable and appropriate for purposes of this proceeding.

23. At this time, it is not appropriate for utilities to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid DEC's and DEP's SISC.

24. It is reasonable and appropriate for DENC to maintain its proposed re-dispatch charge (RDC) avoidance protocol as approved in the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on August 13, 2021, in Docket No. E-100, Sub 167 (Sub 167 Order).

25. It is reasonable and appropriate for DEC and DEP to use the hourly marginal cost of producing energy to calculate avoided costs for QFs that elect to sell energy to DEC and DEP on an "as-available" basis.

26. DEC's proposed seasonal allocation weightings of 96% for winter and 4% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

27. DEC's and DEP's avoided cost rates and rate design are reasonable and appropriate.

28. DENC's proposal to continue to use the energy and capacity rate design approved in the Sub 167 Order is reasonable and appropriate for purposes of this proceeding.

29. 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 167 Order is reasonable and appropriate for purposes of this proceeding.

30. DEC's and DEP's updates and minor administrative revisions to Schedule PP are reasonable and appropriate for the purposes of this proceeding.

31. DEC's and DEP's updates to the Standard Offer PPA are reasonable and appropriate for the purposes of this proceeding.

32. DEC's and DEP's revisions to the Notice of Commitment form appropriately incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872, align the Legally Enforceable Obligation (LEO) process with the new Definitive Interconnection System Impact Study (DISIS) process, and establish a more standardized and efficient process for QFs to proceed from a Notice of Commitment Form to a PPA.

33. DENC's proposed Retrofit Storage LEO Forms are reasonable and appropriate for use by QFs seeking to secure eligibility for a specific avoided cost rate or methodology when adding storage to an existing facility.

34. DENC has reasonably and appropriately revised its LEO Forms to implement FERC Order No. 872.

35. DEC's and DEP's Energy Storage System (ESS) Retrofit avoided cost rates are reasonable and appropriate.

36. The Public Staff's bifurcated rate proposal reflects a compromise consensus among stakeholders and is reasonable and appropriate.

37. It is appropriate to require WCU and New River to offer variable rates to all QFs contracting to sell 1 MW or less based upon their wholesale cost of power that reflect the wholesale rates paid to Carolina Power Partners (CPP).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

The evidence supporting these findings of fact is found in Duke's verified Initial Statement and the exhibits, DENC's Initial Statement and exhibits, the Initial Statement of the Public Staff, and the entire record herein. These findings are essentially jurisdictional and administrative and are not contested.

<u>Summary of the Comments</u>

In its Initial Statement, Duke filed updated standard offer avoided cost rates available to all QFs that meet the eligibility requirements set forth in DEC's and DEP's respective Schedule PPs and that establish LEOs committing to sell the output of their

QF generating facilities to DEC or DEP on or after November 1, 2021, but prior to the initial filing in the next biennial avoided cost proceeding in November 2023. As provided in these schedules:

> In order to be an Eligible Qualifying Facility and receive Energy Credits under this Schedule, the Qualifying Facility must be a hydroelectric or a generator fueled by trash or methane derived from landfills, solar, wind, hog or poultry waste-fueled or non-animal biomass-fueled Qualifying Facility with a Contract Capacity of one (1) megawatt or less, based on the nameplate rating of the generator(s), which are interconnected directly with the Company's system and which are Qualifying Facilities as defined by the Federal Energy Regulatory Commission pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978.

Duke's Schedule PP further states that, pursuant to N.C.G.S. § 62-156(b)(3), electric generation fueled by swine waste and poultry waste may be eligible for a different avoided capacity rate "if Seller sells the output of its facility, including renewable energy credits" to Duke for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements set forth in N.C. Gen. Stat. § 62-133.8(e) and (f).

DENC filed Schedule 19-FP and Schedule 19-LMP, with its Initial Statement, to be available to any QF eligible for these tariffs that has (a) submitted to the Commission a report of proposed construction pursuant to N.C. Gen. Stat. § 62-110.1(g) and Rule R8-65, (b) submitted to DENC an Interconnection Request pursuant to Section 2 or Section 3 of the North Carolina Interconnection Procedures (NCIP), and (c) submitted to DENC a duly executed "Notice of Commitment to Sell the Output of a Qualifying Facility of No Greater Than 1 Megawatt Maximum Capacity to Dominion Energy North Carolina" by no later than the date on which proposed rates are filed in the next biennial avoided cost proceeding.

DENC proposes to continue to offer Schedule 19-LMP to QFs as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at the avoided cost rates determined by the Commission. Under Schedule 19-LMP, DENC would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kilowatts (kW) would be the PJM Dominion Zone (DOM Zone) Day-Ahead hourly locational marginal prices (LMPs) divided by 10 to convert LMP from $/MWh to cents/kWh, and multiplied by the QF's hourly generation in kWh, while the smaller QFs that elect to supply energy only would be paid the average of the PJM DOM Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (kWh) rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DENC used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs shown as the prices per megawatt per day from PJM's Base Residual Auction for the DOM Zone. As in prior proceedings, DENC also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations.

In its Initial Statement, the Public Staff reviews and summarizes the rate schedules proposed by DEC, DEP, and DENC but does not recommend any changes to their proposed standard offer term and eligibility thresholds. No other party proposed changes to the standard offer term and eligibility thresholds or otherwise raised objections to the approval of the rate schedules proposed by DEC, DEP, and DENC.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity.

In past biennial avoided cost proceedings, the Commission determined that, absent an approved, active solicitation, negotiations between a utility and a QF not eligible for the standard offer are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved. Therefore, the Utilities shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, 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 as-available energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during 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.

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 and demonstration that the solicitation meets the Competitive Solicitation Price criteria established under 18 C.F.R. § 292.304(b)(8). Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the parties choose the Marginal Cost Rate option, they may not lock in such rate by a contract term, but instead the rate shall change as the Commission determines in the next biennial proceeding. The Commission recognizes the competitive procurement option for renewable energy facilities provided under N.C.G.S. § 62-110.8, and the ongoing competitive procurement of solar resources pursuant to Session Law 2021-165 (HB 951). *See* Order Authorizing a Competitive Procurement of Solar Resources Pursuant to House Bill 951 and Establishing Further Procedures, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268 (May 26, 2022). The Commission has not received a motion, or issued an order, addressing the exact points when an active solicitation shall be regarded as beginning or ending, nor has the Commission addressed whether any current procurement that it has authorized is considered an active solicitation for PURPA compliance purposes. Accordingly, it is appropriate for the arbitration option to remain available for issues arising during negotiations between a utility and a QF.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for DENC to continue to offer, 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, including the payment of capacity credits based on the PJM RPM, subject to the same conditions as approved in the Sub 106 Order and restated in the Sub 148 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, DENC's Initial Statement and Reply Comments, the Public Staff's Initial Statement and Reply Comments, the Initial Comments of CCEBA/NCSEA and SACE, and the entire record herein.

<u>Summary of the Comments</u>

In its Initial Statement, Duke explains that DEC and DEP have continued to use the peaker method to develop their avoided capacity and energy costs for QFs committing to deliver their full capacity and energy output for a specified fixed future term. Duke's Initial Statement notes that the Commission has approved the use of the peaker method as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs. Duke Initial Statement at 13-14.

Duke states in its Initial Statement that it used the installed cost of a CT unit derived from publicly available industry sources such as the EIA. Duke notes that the installed cost of a CT was one of the Sub 158 Additional Issues that the Commission directed the Utilities to evaluate and apply cost increments and decrements to the publicly available CT cost estimates. Duke states that in compliance with the Commission directive, it worked with the Public Staff and DENC to develop the methodology for calculating CT cost estimates. *Id.* at 17.

As previously approved by the Commission in the Sub 167 Order, Duke calculated CT costs using a greenfield economies of scale adjustment. Duke's greenfield economies of scale methodology uses the avoided capacity cost based upon the EIA's most current published overnight cost of a CT unit and applies a percentage decrement to reflect the economies of scale associated with a 4-unit CT site in the Carolinas. This results in an overnight CT capital cost of $619/kW for use in setting avoided capacity rates in this proceeding. For the fixed operations and maintenance (FOM) cost component, DEC and DEP used the publicly available FOM data from the same EIA data source and adjusted using internal data to reflect the FOM economies associated with a four-unit CT project. Duke Initial Statement at 18-19. Duke further states that additional information supporting these calculations is set forth in DEC/DEP Exhibit 8 to the Duke Initial Statement. *Id.* at 18-19.

In its Initial Statement, DENC states that it has used the peaker method to calculate the avoided capacity cost rates for the Schedule 19FP rate schedule since the 2012 biennial avoided cost proceeding in Docket No. E-100, Sub 136 (Sub 136 proceeding). DENC reports that it engaged in multiple discussions with the Public Staff on this topic throughout 2021 and reported on these discussions through the Sub 158 Additional Issues status updates filed in the Sub 167 docket. DENC further notes that it worked with Duke and the Public Staff to develop the consensus methodology for calculating CT cost estimates. DENC Initial Statement at 19. For this proceeding, based on the agreement with Duke, DENC utilized the 2021 EIA Annual Energy outlook costs for an F-class turbine and did not make any adjustments to the CT equipment costs. DENC did make adjustments to reflect economies of scale and the cost benefits associated with building four CTs at a single site. *Id*. at 20-21.

In its Initial Statement, the Public Staff notes the Commission's consistent approval of the peaker method and indicates that it continues to support the use of the peaker methodology for both Duke and DENC in this proceeding. However, the Public Staff observes that the peaker methodology may not always be appropriate for use in developing avoided costs in North Carolina as the utilities pursue decarbonization and increase their reliance on generation from renewable resources. Public Staff Initial Statement at 24.

The Public Staff states that it agrees with Duke's and DENC's utilization of publicly available CT costs and the economy of scale adjustments, finding them both to be reasonable. The Public Staff notes that in the Sub 167 proceeding, it advocated that a brownfield site cost decrement should be applied given the historic build-out of more recent CTs at brownfield sites. However, after multiple discussions with Duke and DENC, the Public Staff states that a brownfield cost decrement is not appropriate for inclusion in the calculation of avoided capacity rates at this time as the peaker method relies on a "hypothetical" CT and there is no certainty that future CTs will be built on brownfield sites. *Id*. at 14-15.

In addition, the Public Staff notes that in developing the CT costs to be used as the basis for the calculation of avoided capacity rates, both Duke and DENC independently calculated adjustments to the published EIA data, and that both Duke and DENC recommend using an average adjustment of 7.0% to determine the appropriate CT costs. The Public Staff agrees with the approach Duke and DENC utilized in this proceeding in evaluating, calculating, and applying an adjustment to the EIA published data. *Id*. at 15, 29-30.

SACE and CCEBA/NCSEA both argue in their respective Initial Comments that the Commission should begin to reconsider the appropriateness of the peaker method for avoided cost determinations because the peaker method does not accurately capture the marginal capacity cost of the changing electric system required by HB 951. SACE Initial Comments at 3-5; CCEBA/NCSEA Initial Comments at 17-18. SACE further contends that the utilization of an F-class turbine to establish avoided capacity is outdated and that a more appropriate peaking resource would be an aeroderivative gas turbine in the very near term, and batteries or a 100% green hydrogen-powered turbine shortly thereafter. SACE Initial Comments at 8-13, 37.

In their Initial Comments, CCEBA/NCSEA state that they agree with SACE that an aeroderivative gas turbine is the appropriate avoided capacity resource in the near term. CCEBA/NCSEA Initial Comments at 4.

In its Reply Comments, Duke argues that the peaker method remains a reasonable and well-accepted method by which to calculate avoided energy and capacity costs. Nevertheless, given the ongoing development of the Carbon Plan, Duke commits to continued evaluation of the appropriateness of the peaker method in the future and states that it will address this topic in the next biennial avoided cost proceeding in 2024, including any new approaches FERC approved in its recent PURPA rulemaking Order, Order Nos. 872 and 872-A. Duke Reply Comments at 35-36.

Duke disagrees with SACE's proposal to use an aeroderivative turbine unit instead of a F-frame CT in applying the peaker methodology, arguing that the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. Duke asserts in its Reply Comments that even if a utility's next planned unit is not a simple cycle peaker, the peaker methodology still accurately represents a valid estimate of the utility's avoided costs as a simple cycle F-frame peaking unit is typically the least expensive type of traditional resource that DEC and DEP can construct to provide capacity for reliability purposes. *Id*. at 10-11.

Duke further notes that while the Carbon Plan developed in compliance with Session Law 2021-165 will necessarily require high levels of renewable resources, it is unknown at this time what resources will be needed to produce a least cost plan, and Duke asserts that CTs will remain a critical part its resource portfolio in the near term. Therefore, Duke believes that CTs are the appropriate peaking unit for use in this proceeding. *Id*. at 11-12.

In its Reply Comments, DENC asserts that the peaker method is appropriate for this proceeding but acknowledges that the Commission may need to consider additional factors or methods for determining avoided costs in the future. DENC Reply Comments at 3.

Regarding CT costs, DENC asserts in its Reply Comments that the peaker method provides a hypothetical exercise to value capacity and that it is appropriate to continue to use an F-class CT because a higher proportion of its value is derived from the capacity it provides with less value derived from its other attributes. In contrast, aeroderivative gas turbines provide additional benefits beyond simple capacity, such as faster start-up time, faster ramping, and higher efficiency. DENC believes that these added benefits would need to be netted from the avoided capacity cost if any of these three resources were used to model capacity for use with the peaker method. *Id*. at 6-7.

Discussion and Conclusions

Based on the entire record, the Commission finds that the peaker method remains a reasonable method by which to calculate avoided capacity costs at this time. The Commission has approved the use of the peaker method as reasonable and appropriate for deriving forecasted avoided capacity costs in the 2020 Sub 167 proceeding and a number of prior biennial avoided cost proceedings. *See* Sub 167 Order at 60 (Ordering Paragraph 8); 2018 Sub 158 Order at 134 (Ordering Paragraph 10); *see also Order Setting Avoided Cost Inputs,* Docket No. E-100, Sub 140, at 8 (Finding of Fact 6) (issued Dec. 31, 2014) (Sub 140 Phase One Order*)*. The Commission has also developed significant guidance through prior orders in past biennial avoided cost proceedings that inform how the peaker method is applied by utilities in North Carolina and the Commission finds value in retaining this framework for this proceeding.

The Commission further finds based on the entirety of the record that Duke and DENC appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT, a hypothetical F-class CT, and that they developed their respective source information in a manner consistent with the guidance the Commission previously provided. The Commission finds that the approach of Duke and DENC to increase the transparency of the calculation of CT cost estimates is reasonable and appropriate for use in this proceeding. The Commission finds that the use of the 2021 EIA annual energy outlook costs for a F-class turbine, without making any adjustments to the equipment costs, is reasonable. The Commission further finds that the economies of scale adjustment is reasonable and appropriate for this proceeding. The Commission is persuaded by the comments of Duke, DENC, and the Public Staff that a brownfield cost decrement is not appropriate for inclusion in the calculation of avoided capacity rates at this time.

The Commission therefore finds that the CT cost information and adjustments that DEC, DEP, and DENC use are reasonable, consistent with prior Commission orders, and appropriate for purposes of calculating avoided capacity costs in this proceeding. In addition, the Commission determines that it is not appropriate to require DEC, DEP, or DENC to recalculate their avoided capacity costs using an aeroderivative gas turbine as the peaking resource for this proceeding.

The Commission remains open to evaluating the avoided cost method in the future as long as any new or altered method meets PURPA's requirements. In light of the evolving landscape, including the soon to be adopted Carbon Plan that N.C.G.S. § 62-110.9 requires, the Commission directs Duke, DENC, the Public Staff, and other parties to evaluate before the next biennial proceeding whether to propose an alternative method to calculate avoided costs, including those FERC has recently determined to be reasonable and appropriate for calculating avoided costs in Order No. 872 and that are now included in 18 C.F.R. 292.304(b).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, DENC's Initial Statement and Reply Comments, the Public Staff's Initial Statement, and the entire record herein.

Summary of the Comments

Duke's Initial Statement explains that DEC and DEP developed the respective avoided capacity rates consistent with the method the Commission approved in the 2018 Sub 158 Order and the 2020 Sub 167 Order. The Commission's 2018 Sub 158 Order directed each utility to include in future IRPs a clear statement identifying its first year of avoidable capacity need to be used in determining its respective avoided capacity costs. 2018 Sub 158 Order at 10. Duke's Initial Statement and corresponding DEC/DEP Exhibit 8 explain that DEC and DEP generally assess their respective first year of undesignated capacity need as part of the biennial IRP process as well as through annual updates to their IRPs. DEC and DEP last filed their identified first resource needs with the Commission in September 2020 as part of their 2020 IRPs. As the Commission's June 29, 2021 Order in Docket No. E-100, Sub 165 waived DEC's and DEP's obligation to file 2021 IRP updates under Rule R8-60(h)(2), Exhibit 8 to Duke's Initial Statement presents DEC's and DEP's updated first years of undesignated capacity need, calculated as of October 2021. Duke Initial Statement at 15-16; DEC/DEP Exhibit 8 at 2.

DEC's first year of avoidable undesignated capacity need shifts to 2028 from the 2026 designation in the 2020 Sub 167 proceeding, reflecting the additional approximately 175 MW of designated capacity that will be added to the DEC system through the Integrated Volt/Var Control (IVVC) program, which the Commission approved in March 2021. DEP's first year of avoidable undesignated capacity need remains the same in 2024.

Consistent with the 2020 Sub 167 Order and N.C.G.S. § 62-156(b)(3), DEC's and DEP's Schedule PP rates also appropriately include alternative avoided capacity rate calculations, which recognize that certain QFs fueled by swine waste and poultry waste and certain hydro power QFs less than 5 MW are assigned immediate capacity value. Duke Initial Statement at 15.

In its Initial Statement, DENC states that on September 8, 2021, it filed an addendum to its 2021 IRP Update on September 1, 2021, in Docket No. E-100, Sub 165 identifying DENC's next undesignated capacity need as arising in 2024. The calculation of seasonal levelized rates shown in its Initial Statement included no avoided capacity costs through 2023 since DENC's 2021 IRP Update showed the first avoidable capacity in 2024. DENC Initial Statement at 22-23. On January 7, 2022, DENC filed corrected standard avoided capacity rates, explaining that it recalculated its proposed capacity rates to reflect DENC's accurate capacity position as its previous calculations inadvertently excluded approximately 500 MW of solar capacity. As a result, DENC's updated first year of undesignated capacity need is 2026.

In its Initial Statement, the Public Staff sets out its analysis of DEC's and DEP's updated first years of need. The Public Staff states that DEC's and DEP's calculations of avoided capacity rates appropriately reflect the present value of avoided capacity costs beginning in their respective first years 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, and the first year of avoidable undesignated capacity need for DEC, DEP, and DENC is reasonable and based upon each utility's most recently filed IRP. Public Staff Initial Statement at 28-29. No other parties commented on this issue.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission determines that the avoided capacity cost of DEC, DEP, and DENC have been calculated consistently with the North Carolina General Statutes and the Commission's prior orders on this matter.

No party disputed the proposed first year of need of DEC, DEP, or DENC, or their proposed standard offer schedules showing that, in certain circumstances, QFs fueled by swine waste, poultry waste, and hydropower receive capacity payments that 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 capacity need.

The Commission finds DEC's and DEP's updated calculation of their respective first years of avoidable capacity need to be reasonable, and the Commission determines that DEC's and DEP's first year of need and proposed avoided capacity rates are appropriate and therefore approves them. The Commission further determines that DENC's corrected addendum to its 2021 IRP Update submitted on January 7, 2022, in Docket No. E-100, Sub 165 identifies that DENC's next year of undesignated capacity need is 2026, and that DENC appropriately relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, DENC's Initial Statement and Reply Comments, the Public Staff's Initial Statement, and the entire record herein.

Summary of the Comments

Duke's Initial Statement states that the Commission has previously recognized the PAF as a capacity multiplier designed to address the fact that standard avoided capacity rates are paid on a per-kWh basis, such that setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours. According to Duke, this leaves the QF without any reasonable opportunity to experience outages during each peak hour to receive the total avoided capacity payment. Duke explains that the PAF recognizes that the utilities' generating units experience outages during peak periods and thus a QF should not be required to operate during 100% of the on-peak hours to receive a full capacity payment for the year. Specifically, Duke explains, in the 2018 Sub 158 proceeding, the Commission approved the continued recognition of a PAF in determining the appropriate calculation of avoided capacity to be paid to QFs. The 2018 Sub 158 Order reiterated the Commission's finding in the 2016 Sub 148 Order that inclusion of a PAF in avoided capacity rates is appropriate and the PAF should be based upon a metric or metrics that assess generating unit "availability." As Duke explains, the Commission approved Duke's proposed PAF of 1.05 in the 2018 Sub 158 proceeding based upon the equivalent availability (EA) metric and the use of five years of historic outage rate data during Duke's critical peak season months. Sub 158 Order at 41. In accepting Duke's utilization of the EA metric for calculating the PAF, Duke explains, the Commission additionally accepted the Public Staff's recommendation for the utilities to consider reliability metrics other than the EA. The Commission directed Duke and the Public Staff to address the appropriateness of using the Equivalent Unplanned Outage Rate (EUOR) metric in the following 2020 Sub 167 proceeding. Duke Initial Statement at 19.

Duke explains that DEC and DEP continued to utilize the EA metric to calculate the PAF in the 2020 Sub 167 proceeding in an effort to "streamline" the 2020 avoided cost proceeding. Nevertheless, Duke states that it committed to discussing the appropriateness of utilizing the EUOR metric with the Public Staff prior to this avoided cost proceeding. Based on that commitment, Duke explains, the Commission urged the parties to try to reach consensus on the appropriateness of using the EUOR metric prior to their initial filing in the present docket. *Id*. at 20.

In preparation for this avoided cost proceeding, Duke states that it worked with the Public Staff and DENC to consider the use of the EUOR metric and other reliability metrics for developing the PAF. Based on these discussions, Duke explains, Duke, the Public Staff, and DENC reached a consensus to adopt the Equivalent Unplanned Outage Factor (EUOF) metric for developing the PAF. Like the EUOR metric, the EUOF metric includes the impact of maintenance outages that can also occur during peak demand periods and appropriately excludes planned outages from the calculation. Duke explains that it compiled five years (2016-2020) of Generating Availability Data System (GADS) data and calculated the EUOF for the entire generation fleet, excluding DEC and DEP-owned solar resources, which is consistent with the practice of using five years of GADS data in Duke's planning models. According to Duke, use of the EUOF metric also allowed it to align calculation of the PAF with the actual periods that DEC and DEP pay for capacity. For DEC, Duke states, this includes the winter months of December-March and the summer months of July-August. To align with DEP's actual capacity payment period, Duke explains that the DEP data was based only on the winter months of December-March and does not include any summer months. Based upon these calculations and the agreed-upon methodology, Duke states that DEC's and DEP's respective systems weighted

EUOF (WEUOF) during this timeframe averages to approximately 4%, which results in a PAF of 1.04 for both DEC and DEP. *Id*. at 21.

Duke's Initial Statement also provides Duke's position on continuing the PAF for hydroelectric ("hydro") QFs that are eligible for the standard offer (1 MW or less). In past biennial avoided cost proceedings, Duke notes, North Carolina's legacy implementation of PURPA afforded hydro QFs with unique treatment that resulted in the Utilities and the Commission providing run-of-river hydro QFs without storage a 2.0 PAF.[2] Duke Initial Statement at 21. As Duke notes, the Commission approved a 2.0 PAF for run-of-river hydro QFs more than two decades ago in the 1996 avoided cost proceedings in Docket No. E-100, Sub 79. Duke Initial Statement at 22 (citing *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 79, at 19 (issued June 19, 1997)). Based in part on that unique legislative treatment and the Commission's then-existing 2.0 PAF for run-of-river hydro QFs, Duke explains that DEC, DEP, and the NC Hydro Group entered into a stipulation in Docket No. E-100, Sub 140 (Hydro Stipulation), agreeing that, among other things, Duke would continue to include the previously-approved 2.0 PAF in standard offers and to calculate the avoided cost rates for small hydro QFs of 5 MW or less through December 31, 2020. *Id*. at 22 (citing Hydro Stipulation, at ¶¶ 3(a), 4).

Duke notes that the General Assembly amended the State's implementation of PURPA through HB 589 in 2017 and HB 329 in 2019 to no longer designate hydroelectric generating facilities as unique small power producers, while, at the same time, establishing flexibility for Duke to negotiate longer-term avoided cost purchase contracts and to immediately recognize the capacity contributions of certain legacy hydro QFs in calculating future avoided cost rates. *Id*. (citing N.C.G.S. §§ 62-156(b)(3), (c)). Because of these changes, Duke states, the Commission found it appropriate in Docket No. E-100, Sub 158 "to consider again the question of the appropriate PAF to apply in calculating capacity rates to run-of-river hydro QFs after the natural expiration of the Hydro Stipulation." *Id*. (citing Sub 158 Order at 42).

In the 2020 Sub 167 proceedings, when the expiration of the Hydro Stipulation was imminent, Duke stated that it would retain the 2.0 PAF for run-of-river hydro QFs eligible for the standard offer (in effect from November 1, 2020 until October 31, 2021), but noted that the Hydro Stipulation was set to expire on December 31, 2020. *Id*. at 23 (citing *Joint Initial Statement*, Docket No. E-100 Sub 167, at 17-18 (Nov. 2, 2020)). In the 2020 Sub 167 Order, the Commission cited the expiration of the Hydro Stipulation and provided that after December 31, 2020, DEC and DEP "are no longer required to offer a 2.0 PAF to run-of-river hydro QFs greater than 1 MW but less than 5 MWs." Sub 167 Order at 20. In the Sub 167 Order, the Commission further directed Duke to address the appropriate PAF for run-of-river hydro QFs 1 MW or less in this avoided cost proceeding. *Id*. at 23.

[2] Prior to HB 589's enactment in 2017, 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)).

In addressing this issue for this avoided cost proceeding, Duke asserts that it is now appropriate to also discontinue the elevated PAF for run-of-river hydro QFs with capacity of 1 MW or less. Both the Hydro Stipulation and the 2020 Sub 167 standard offer have expired. Thus, in this first avoided cost proceeding following the expiration of the Hydro Stipulation, Duke proposes standard offer avoided cost rates for run-of-river hydro QFs that reflect the same standard PAF of 1.04 for all QFs, not the elevated and outdated PAF of 2.0 for only run-of-river QFs with capacity of 1 MW or less. *Id*.

In its Initial Statement, DENC notes that it discussed with the Public Staff the development of the PAF on multiple occasions. For purposes of this proceeding, DENC reached consensus with the Public Staff that DENC will use the Weighted Equivalent Unforced Outage Factor (WEUOF), which accounts for unit unavailability caused by maintenance and forced outages, to determine the PAF. DENC agreed with the Public Staff to use a 5-year average, instead of the previously used 3-year average, to calculate the WEUOF. DENC and the Public Staff also agreed that DENC will have flexibility to determine the months to be used in the overall PAF calculation and will provide support for use of those months in DENC's Initial Statement. As a result, in this proceeding, DENC calculated a PAF of 1.07 using 5 years of history for the months January, February, June, July, and August and it utilized these months for consistency with PJM's "Peak Period Months" in the PJM Manual 10. DENC Initial Statement at 23-24.

In its Initial Statement, the Public Staff agrees with DEC's, DEP's, and DENC's proposed PAF adjustments and supports the use of the WEUOF metric for each utility's respective generation fleet. The Public Staff notes, however, that the WEUOF is calculated using data from GADs, which does not currently require solar generation reporting. Because neither Duke nor DENC reports outages from their solar generation facilities into GADs, the Public Staff notes that solar outage data is excluded from the WEUOF. The Public Staff recognizes that solar outage data at this time would be unlikely to impact the WEUOF and the PAF, but Duke and DENC are now subject to carbon reduction legislation requiring the construction or acquisition of utility-owned solar assets. Therefore, the Public Staff recommends that Duke and DENC address the inclusion of solar and wind generator outage data in calculating the PAF in their next avoided cost filings and the then-current status of outage reporting requirements set by the North American Electric Reliability Corporation (NERC), which maintains GADS. Public Staff Initial Statement at 15-16. In their Reply Comments, Duke agrees with the Public Staff's recommendation to address solar and wind generator outage data in calculating the PAF in DEC's and DEP's next avoided cost filing. With the expected growth in utility-owned solar and potential wind facilities, Duke believes that including these facilities in the determination of the PAF once the GADs data becomes available is appropriate. Therefore, Duke agrees to address inclusion of the solar and wind generator outage data in the PAF calculation in future avoided cost filings.

In its Reply Comments, DENC does not oppose the Public Staff's recommendation, and stated that if the Commission agrees with the Public Staff, DENC will address the appropriateness of including solar and wind generator outage data in the calculation of the PAF in its initial filing for the next biennial avoided cost proceeding.

DENC also states that it does not oppose providing the status of NERC outage report requirements in the next biennial proceeding, should the Commission find that to be appropriate. DENC states that when the NERC reporting requirements, outage coding protocols, and any updated WEOUF calculation definitions are known, it will best be able to address the appropriateness of including solar outage data in the calculation of its PAF, including whether it could accomplish incorporation of such data in a manner consistent with the peaker method. DENC Reply Comments at 4-5.

Discussion and Conclusions

Based on the foregoing, the Commission finds and concludes that Duke's proposed PAFs of 1.04 for QFs, excluding hydro QFs of 1 MW or less, is reasonable and appropriate. As directed by the Commission, Duke, DENC, and the Public Staff worked together to consider the use of other reliability metrics for developing the PAF. These discussions resulted in a consensus to adopt the WEUOF metric for each utility's respective generation fleet. No party contested this methodology. Accordingly, the Commission finds and concludes that the WEUOF metric is reasonable and appropriate to use in this avoided cost proceeding to calculate the PAF.

At this time, the system WEUOF calculation is based on the performance of the respective DEC and DEP generation fleets, excluding the Company-owned solar facilities. The Commission agrees with the Public Staff that solar outage data, at this time, is unlikely to impact the WEUOF and the PAF. The carbon reduction legislation that explicitly directs Duke to build or acquire utility-owned solar assets, however, will result in growth in Duke-owned solar and potential wind facilities. Duke and the Public Staff agreed that including these facilities in the determination of the PAF once the GADS data for these facilities become available is reasonable and appropriate. The Commission agrees and, therefore, directs Duke to address the inclusion of solar and wind generator outage data in the PAF calculation in future avoided cost proceedings.

Based upon the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to use a PAF of 1.07 in its avoided cost calculations for all QFs and to use the WEUOF method to determine the PAF. The Commission finds that DENC's proposal to use the WEUOF method to calculate its PAF, as agreed to with the Public Staff, is reasonable for purposes of this proceeding. Usage of the WEUOF methodology meets the Commission's directive in the Sub 158 and 167 Orders to consider the appropriateness of using other reliability indices such as the EUOR metric to support development of the PAF. The Commission also finds DENC's and the Public Staff's agreement to use a 5-year average, with DENC determining the months used, in the PAF calculation to be reasonable as the months selected by DENC align with PJM's "Peak Period Months" in the PJM Manual 10.

The Commission is not persuaded by Duke's proposal to discontinue the 2.0 PAF for run-of-river Hydro QFs that are subject to the standard offer. Although the Hydro Stipulation has expired, and no party offered any justification for extending the 2.0 PAF, the parties did not fully litigate this issue in this proceeding. Accordingly, the Commission directs Duke to continue the 2.0 PAF for run-of-river Hydro QFs that are subject to the standard offer. The Commission 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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting these findings of fact is found in Duke's Initial Statement, the Public Staff's Initial Statement, SACE's Initial Comments, CCEBA/NCSEA's Initial Comments, Duke's Reply Comments, the Public Staff's Reply Comments, and the entire record herein.

Summary of the Comments

Duke's Initial Statement outlines the history of the natural gas forecast in prior avoided cost proceedings. Since the 2016 Sub 148 Order, the Commission has determined that DEC and DEP should be required to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before transitioning to fundamental forecast data for the remainder of the planning period. 2016 Sub 148 Order at 109 (Ordering Paragraphs 5-6); 2018 Sub 158 Order at 136 (Ordering Paragraph 20); 2020 Sub 167 Order at 60 (Ordering Paragraph 12). Duke elected to continue that approach in this proceeding. Duke specifies that it is relying upon forward market price data for eight years (2022-2029) as an indicator of the near-term future commodity costs of natural gas for purposes of calculating its avoided energy cost rates before transitioning to fundamental forecast data starting in year nine (2030-2031). Duke explains that it obtained the market prices from an actual forward purchase to determine the market price of gas and forward market liquidity. Duke notes that this approach is consistent with the 2018 Sub 158 Order and the 2020 Sub 167 Order, and it achieved consensus with the Public Staff on this approach. Duke Initial Statement at 25-26.

In its Initial Statement, the Public Staff explains that it has reviewed Duke's Prosym inputs for the price forecasts for delivered natural gas and found them to be reasonably consistent with the 2020 Sub 167 Proceeding and appropriate for this proceeding. Public Staff Initial Statement at 40. The Public Staff expressed concern with Duke's calculation of its 10-Year fixed energy rate due to the over-reliance on lower-priced shale gas in the calculation. The Public Staff notes that the Commission directed Duke to file a Supplemental 2020 IRP portfolio reflecting limited gas from the DS Hub (the Limited DS Hub Gas portfolio). The Public Staff expects to address this issue in the Carbon Plan proceeding and does not recommend the use of the Limited DS Hub Gas portfolio as the basis for the avoided energy rates at this time. *Id*. at 41-42.

In its Initial Comments, SACE states that Duke's natural gas commodity price forecast methodology should be revised, and that an eight-year-forward-contract methodology inherently produces inaccurate results. SACE states that the increase in natural gas prices over the past year shows the potential inaccuracy of forward market prices and the benefit of blending multiple fundamental forecasts to reduce inaccuracies due to commodity volatility. SACE points out that Duke anticipates that it will replace the

10-year-forward-contract methodology used in its prior IRPs in its proposed Carbon Plan with a “natural gas price forecast [that] relies upon five (5) years of natural gas market-based pricing, followed by three (3) years of transitioning from market-based pricing before fully utilizing fundamentals based natural gas pricing forecast starting in 2031 for the remaining study period.” SACE states that the Commission should require Duke to adopt the basic methodology applied by DENC using 18 months of forward market prices, then 18 months of blended prices, before switching fully to fundamental forecasts, averaging the Spring 2021 IHS and EIA 2021 Reference Case data for purposes of the fundamental forecast. SACE states that this approach is essentially identical to the approach required by the South Carolina Public Service Commission in Duke’s recent IRP proceeding. SACE Initial Comments at 22-23.

CCEBA/NCSEA state in their Initial Comments that the Commission has previously found that it is appropriate for Duke to apply the same natural gas forecast methodology in its IRP proceeding that it uses to calculate avoided cost rates. CCEBA/NCSEA recommend that the Commission require Duke to use fewer years of forward market prices, with a transition to fundamental forecasts for the remainder of the applicable planning period. Specifically, CCEBA/NCSEA recommend that the Commission require Duke to adopt the recommendations of CCEBA/NCSEA Witness Kevin Lucas as presented in the 2020 IRP Proceeding in Docket No. E-100, Sub 165, which would require Duke to utilize 18 months of forward market prices before transitioning to a blended fundamentals forecast, using at least two reputable sources, for the remainder of the planning period. CCEBA/NCSEA Initial Comments at 21-22.

In its Reply Comments, Duke notes that its natural gas forecasting method is consistent with the Commission’s orders in the past three avoided cost dockets. Duke states that SACE and CCEBA/NCSEA’s comments largely reiterate the same points that each party made in past proceedings on the issue of natural gas forecasting methodology. Duke Reply Comments at 14-16.

In its Reply Comments, the Public Staff states that it does not recommend Duke recalculate its avoided energy cost in this proceeding using a different natural gas forecasting methodology because the current method technically complies with past Commission orders and is in alignment with the natural gas forecasting methodology in the 2020 IRP Supplemental Portfolio B. The Public Staff does note, however, that, in stakeholder meetings related to the 2022 Carbon Plan, Duke has indicated it intends to use five years of forward market prices followed by a three-year period blending forward market prices with a fundamental price forecast. While the Public Staff states that it supports this approach and recommends that Duke use this forecasting methodology in future avoided cost filings, it does not recommend adoption of the new methodology at this time. The Public Staff believes that the natural gas forecasting methodology should remain consistent between the IRP and avoided cost determinations, and points out that Duke has not yet filed its proposed Carbon Plan utilizing the proposed methodology. Public Staff Reply Comments at 3-4.

Discussion and Conclusions

The Commission acknowledges that this issue has been contentious in the last three avoided cost proceedings. Duke's proposed natural gas forecasting method in this proceeding is consistent with the methodology approved by the Commission in the prior avoided cost proceedings, and the Public Staff has agreed that Duke's proposed method is appropriate for use in this proceeding. Accordingly, after careful consideration, the Commission is not persuaded that a change in the fuel forecasting method is appropriate at this time.

The Commission notes that while Duke stated in stakeholder meetings related to the 2022 Carbon Plan that it plans to use five years of forward natural gas followed by three years of blending before transitioning to fundamental forecasts in its proposed Carbon Plan, Duke has not yet filed its Carbon Plan utilizing the proposed method. The Commission is open to revisiting this decision in the 2023 biennial avoided cost proceeding, which will take place after the Commission has approved an initial Carbon Plan and an updated natural gas forecasting methodology. The Commission further notes that once the Commission approves the Carbon Plan, the natural gas forecasting method proposed by Duke in its Carbon Plan will be more appropriate for use in the subsequent avoided cost biennial proceeding. The Commission agrees with the Public Staff that consistency is appropriate and warranted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, the Public Staff's Initial Statement, and the entire record herein.

Summary of the Comments

The Public Staff's Initial Statement summarizes its general concern regarding Duke's reliance on forecasted lower cost natural gas pricing utilizing the Appalachian basin's lower cost Dominion South hub (DS Hub), which the Public Staff addressed in its Initial Comments in the 2020 Sub 165 IRP Proceeding. The Public Staff explains that the Commission's Sub 165 IRP Order required Duke to file a Supplemental 2020 IRP Limited DS Hub Gas portfolio, which Duke filed on February 9, 2022 (Supplemental Portfolio B). The Public Staff explains that relative to Duke's Portfolio B which had no limits on gas transportation access assumptions, Supplemental Portfolio B contained 2,448 MW fewer natural gas fired combined cycle generation in the 15-year plan, and this reduction was replaced with CTs, solar, solar plus storage, and onshore wind. The Public Staff explains that this shift increased projected total system costs through 2050 by $5.2 billion, or 6.3%. The Public Staff states that it does not recommend the use of Supplemental Portfolio B as the basis for calculating avoided energy, but states that it would address this issue, the appropriate level of reliance on current gas transportation assumptions, and its concerns with the Mountain Valley Pipeline's (MVP) construction delays in its supplemental IRP comments and its comments on Duke's 2022 Carbon Plan. Public Staff Initial Statement at 41-42.

In Reply Comments, SACE states that it shares the Public Staff's concern that Duke's longer-term projections of avoided energy costs may be inaccurate due to potential overreliance on lower-priced shale gas, which depend on the assumption that certain gas pipelines will be constructed. Nevertheless, SACE agrees with the Public Staff's recommendation that Duke not use the Supplemental Portfolio B as the basis for calculating avoided energy rates in this proceeding. SACE recommends close scrutiny of avoided energy calculations in future proceedings to ensure that they are based on accurate assumptions about gas transport. SACE Reply Comments at 6.

In its Reply Comments, Duke acknowledges the concerns raised by the Public Staff regarding DEC's and DEP's reliance upon forecasted lower cost natural gas pricing utilizing the DS Hub. Duke notes that despite these concerns and the uncertain regulatory future for the MVP pipeline, the Public Staff does not recommend the use of Supplemental Portfolio B as the basis for calculating avoided energy rates at this time. Duke finally states that the extent of its reliance on DS Hub gas is an issue that will be further considered as part of the 2022 Carbon Plan and updated as regulatory circumstances surrounding the MVP pipeline provide more clarity regarding its eventual viability. Duke Reply Comments at 16-17.

<u>Discussion and Conclusions</u>

The Public Staff in this proceeding has identified planning uncertainties concerning new natural gas transportation capacity into North Carolina considering the Atlantic Coast Pipeline cancelation as well as the challenging recent regulatory landscape for building newer natural gas pipelines. Duke does not dispute that those planning uncertainties exist. As a result, regarding the reasonableness of Duke's natural gas forecasting transportation assumptions in this proceeding, the Commission finds the Public Staff's and SACE's stated concerns as well as Duke's responses to be reasonable and appropriate for purposes of this proceeding.

In summary, the Commission accepts Duke's use of its natural gas transportation and pricing assumptions as reasonable only for the limited purpose of calculating avoided costs in this proceeding. In its review of the 2022 Carbon Plan in Docket No. E-100, Sub 179, the Commission will further consider the appropriateness of Duke's gas transportation assumptions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, the Public Staff's Initial Statement, and the entire record herein.

<u>Summary of the Comments</u>

Duke's Initial Statement states that after discussing the avoided fuel hedge value of renewable energy with the Public Staff, DEC and DEP have used the Black-Scholes option pricing method to calculate a fuel hedging adjustment that aligns with the method

DENC used and the Public Staff and the Commission accepted in recent avoided cost proceedings. According to Duke, DEC's and DEP's Black-Scholes calculation results in a fuel hedge value of $0.02 per MWh, and DEC and DEP incorporated that value in their avoided energy cost in this docket. Duke Initial Statement at 27.

In its Initial Statement, the Public Staff notes that Duke included 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 $0.02 per MWh to supplement its avoided energy rates. The Public Staff agrees that this was consistent with the Commission's 2018 Sub 158 Order, and it recommends no changes or modifications to Duke's fuel hedging value. Public Staff Initial Statement at 47-48.

Other than DEC's and DEP's acknowledgement that the fuel hedging value was an issue upon which they and the Public Staff had agreed prior to the November 1, 2021 filing of the Duke Initial Statement, no party raised the issue of the fuel hedging value in reply comments.

Discussion and Conclusions

Duke and the Public Staff have agreed upon an appropriate hedging value and methodology for calculating that value. In this proceeding, no party contested Duke's methodology for calculating the fuel hedging value or the fuel hedging value of $0.02 per MWh itself. The Commission agrees with the Public Staff that the calculation was consistent with the 2018 Sub 158 Order. Therefore, based on the foregoing, the Commission concludes that Duke's fuel hedging value is reasonable and approves it.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

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

Summary of the Comments

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 Updated IRP filed on September 1, 2021, in Docket No. E-100, Sub 165 (2021 IRP Update) 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 fall 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). DENC notes that, consistent with the Sub 167 Order, the third category does include RGGI costs but does not include federal carbon 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 167 Order. DENC Initial Statement at 5-6.

Regarding forward commodity prices, DENC states that, consistent with past practice, it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International (ICF) prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the Sub 167 Avoided Cost Case. *Id*. at 7.

DENC explains that, consistent with prior Commission direction, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that locational marginal prices (LMPs) in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs in support of its adjustment. *Id*. at 7-8.

DENC proposes to continue its use of the Black-Scholes Model to determine fuel hedging benefits as the Public Staff proposed in Docket No. E-100, Sub 140, with a resulting fuel price hedging value of $0.02/MWh, which was assumed constant for all years of the Schedule 19-FP contract. *Id*. at 9-10.

In its Initial Statement the Public Staff states that based on its review of the PLEXOS inputs, the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs. The Public Staff confirms that DENC's calculation of avoided energy rates is consistent with the Sub 158 Order, as is DENC's inclusion of fuel hedging values based on the Black-Scholes Model. The Public Staff does not raise concerns with DENC's forecasted natural gas prices or DENC's calculation of the fuel hedge value. Public Staff Initial Statement at 47-48.

In its initial comments, SACE states that DENC's approach to fuel forecasting is reasonable for combining forward prices and fundamental forecast components of an overall price forecast in this proceeding, but asserts that DENC should average multiple fundamental price forecasts rather than use its private ICF fundamentals forecast to calculate its natural gas forecasting. Specifically, SACE argues that the Commission should require DENC to average its ICF fundamentals forecast with the 2021 EIA annual energy outlook reference case. SACE Initial Comments at 38.

In their Initial Comments, CCEBA/NCSEA state that they agree with SACE that the DENC approach to forward gas prices is reasonable. CCEBA/NCSEA Joint Initial Comments at 4.

In its Reply Comments, DENC states that its current approach of using the ICF fundamental forecast, on its own, continues to be appropriate for estimating avoided energy cost rates. DENC explains that ICF conducts regional forecasts for electricity as well as natural gas and other commodities that allow DENC to use relevant and correlated forecasts versus mixing ICF price forecasts for energy and other commodities with an EIA forecast for Henry Hub, which would skew the dispatch and economic value of DENC's natural gas-fired units. DENC Reply Comments at 11-12.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed avoided energy inputs are reasonable for the purposes of this proceeding and are approved.

Based on the comments of DENC and the Public Staff, the Commission determines that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings is appropriate and declines to accept SACE's recommendation to average multiple fundamental price forecasts.

Based on the record in this proceeding including the review of the Public Staff, the Commission concludes that DENC has calculated avoided hedging costs appropriately for purposes of this proceeding and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value.

Additionally, based on the uncontested evidence presented by DENC updating the continued disparity in LMPs in its service territory, the Commission concludes that it continues to be appropriate for DENC to include the historical average congestion differentials for all periods in its calculation of proposed energy costs for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is found in Duke's Reply Comments, DENC's Initial Statement and Reply Comments, the Public Staff's Initial Statement, SACE's Initial Comments, and the entire record herein.

Summary of the Comments

DEC's and DEP's avoided cost calculation method does not include an assumed avoided cost of carbon emissions, and Duke's Initial Statement is silent on the issue. In its Initial Statement, the Public Staff notes that Duke calculated avoided energy rates using Portfolio A from DEC's and DEP's 2020 IRPs, which is the base case without carbon policy.

The Public Staff acknowledges that the Carbon Plan to be implemented pursuant to N.C.G.S. § 62-110.9 imposes a limit on total CO_2 emissions (mass cap), but notes that it does not impose a direct price on CO_2 emissions. Further, while setting a mass cap in capacity expansion models will yield a model result with an implied cost of carbon, the Public Staff notes that not all of the total cost of carbon abatement is avoidable in the context of calculating avoided costs. Public Staff Initial Comments at 8-9. The Public Staff explains that a portion of the implied cost of carbon derived from the Carbon Plan may include higher capital costs associated with the purchase or construction of new renewable generation facilities, but that some of those costs may not be avoided when purchasing incremental renewable energy from QFs. Accordingly, the Public Staff asserts that prior to approval of the Carbon Plan, the implied cost of carbon cannot be accurately determined and recommends that the Commission approve DEC's and DEP's avoided costs rates using Portfolio A without a carbon price at this time. Once the Commission approves a Carbon Plan and determines an avoidable cost of carbon, if any, within those proceedings or in subsequent proceedings, the Public Staff recommends that the Commission direct DEC and DEP to use the Carbon Plan as the expansion portfolio and include any Commission-approved avoidable cost of carbon in its calculation of costs in the next avoided cost filing. *Id*. at 6-9.

As noted above, DENC did not include the federal carbon costs in its avoided energy rates but does include RGGI costs. DENC Initial Statement 5-6.

The Public Staff notes that DENC calculated its proposed avoided energy rates using its generation expansion Plan B from its 2021 IRP Update in Docket No. E-100, Sub 165, and that Plan B is the least-cost plan that complies with all applicable state law, including the Virginia Clean Economy Act and Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI), effective January 1, 2021. The Public Staff states that while there is some uncertainty regarding the projected future cost of RGGI carbon allowances as well as whether Virginia will remain a member of RGGI, the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law. The Public Staff concludes that therefore it is appropriate for DENC to utilize generation expansion Plan B and to include the cost of RGGI carbon allowances in the production cost models that are used to calculate avoided energy rates. Public Staff Initial Statement at 10.

SACE argues that the carbon reduction mandates of N.C.G.S. 62-110.9 are "self-executing" and make it possible to calculate a known and verifiable cost of carbon appropriate to be factored into avoided costs in this proceeding and in advance of a Commission-approved Carbon Plan. Recognizing that the Commission has not finalized and approved a Carbon Plan, SACE argues that the Commission could look to Duke's base case with carbon policy in their respective 2020 IRPs as a reasonable proxy for the price of carbon. SACE further argues that HB 951's mandate to "take all reasonable steps" to achieve the stated carbon reduction mandates "arguably requires the Commission to include a cost of carbon in avoided cost rates" since establishing a cost of carbon in avoided cost rates would increase the cost of carbon-emitting generation and encourage zero-emitting generation and reduce emissions. For these reasons, SACE argues that the Commission should order Duke to recalculate its avoided costs using Duke's 2020 IRP base case with carbon policy or RGGI allowance cost as a reasonable proxy for the applicable cost of carbon, starting at $5/ton in 2025 and escalating at a rate of $5/ton per year thereafter. SACE Initial Comments at 33-34.

Duke addresses SACE's argument in its Reply Comments. Similar to the Public Staff, DEC and DEP note that the Commission has previously determined that carbon emission-related cost would only be avoidable where such costs are "known and verifiable."[3] Duke argues that SACE fails to explain how incorporation of a hypothetical backward-looking carbon cost adder that is not based on any known or measurable carbon price or tax into the avoidable costs to be paid by ratepayers to QFs contracting under the Schedule PP is reasonable – let alone needed – to achieve HB 951's carbon reduction goals. Instead, Duke agrees to the solution proposed by the Public Staff – that it should use the future base portfolio selected in the Carbon Plan proceeding to calculate avoided cost rates in the next biennial avoided cost proceeding. Duke notes that because the Commission will formally approve the Carbon Plan, the modeled cost of the resources identified to meet HB 951's carbon reduction goals will then be known and verifiable. Duke Reply Comments at 17-21.

In its Reply Comments, SACE opposes the Public Staff's proposal that the Commission should wait until after it approves the Carbon Plan to include a cost of avoided carbon emissions in DEC's and DEP's avoided costs calculations. SACE argues that the Carbon Plan will continue to evolve and suggests that the Commission should not wait until all inputs are absolutely certain before including an avoided cost of carbon in avoided cost rates. SACE Reply Comments at 2-3. CCEBA/NCSEA, in their Reply Comments, agree with SACE that it would not be appropriate to delay the modeling of Carbon Plan compliance for avoided cost purposes until 2030, the deadline for the 70% reduction mandate. CCEBA/NCSEA do not object to the Public Staff's proposal to further evaluate the appropriate application of the Carbon Plan in the calculation of avoided costs after approval of the Carbon Plan. However, CCEBA/NCSEA propose that it would be appropriate for the parties to address this issue *before* DEC and DEP make their 2023 avoided cost filings, in either this proceeding, the Carbon Plan proceeding, or another docket in the Commission's discretion. CCEBA/NCSEA Reply Comments at 4.

Discussion and Conclusions

Based upon the foregoing evidence and the entire record in this proceeding, the Commission finds that it is not appropriate to include an implied cost of avoided carbon emissions in DEC's and DEP's avoided costs calculations at this time. As the Commission has previously concluded, utilities should base their avoided costs on "known and verifiable" costs, and the "known and verifiable" costs do not yet include the cost of carbon emissions. The Commission notes its findings in the 2020 Sub 167 Order and the earlier Sub 140 Phase One Order that avoided costs should be calculated using only "known and verifiable" costs, and that "speculative costs" that are not "sufficiently certain" to be avoided by customers should not be included in avoided costs at this time. The Commission determines that DEC and DEP have appropriately calculated avoided energy costs that do not include carbon emissions-related costs in this proceeding.

The Commission does not agree with SACE's assertions that carbon emission costs now are "known and verifiable" simply in light of the North Carolina General

[3] *2020 Sub 167 Order* at 7, 33 (recognizing that "ratepayers should not bear speculative or uncertain costs that are not avoided through purchase of power from a QF through the avoided cost rates that they ultimately pay"); *see also Sub 140 Phase One Order* at 8 (Finding of Fact 14), 42–44.

Assembly's passage of N.C.G.S 62-110.9, and the Commission is not persuaded that Duke's 2020 IRP base case with carbon policy portfolios could serve as a reasonable proxy for an implied cost of carbon in advance of developing the Carbon Plan. As both Duke and the Public Staff note, there is no certainty regarding the resources to be developed or any future implied cost of carbon to be included in the approved Carbon Plan and, therefore, there are no real or known and verifiable costs associated with future carbon emission reductions under the Carbon Plan that are avoidable at this time.

The Commission does anticipate that the next avoided cost proceeding will address the cost of carbon and the approved Carbon Plan. The Commission directs DEC and DEP to explain in their next biennial avoided cost filings how they have incorporated the Carbon Plan into avoided cost calculation and rate design.

The Commission further determines that it is reasonable for purposes of this proceeding to approve DENC's avoided energy rates based on modelling that includes RGGI costs and excludes federal CO2 costs, as DENC's RGGI costs are sufficiently "known and verifiable" based on current law. As the Public Staff notes, there is some uncertainty regarding future RGGI costs; however, the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law and is therefore appropriate to be used in determining DENC's avoided energy rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-18

The evidence supporting this finding of fact is found in Duke's Initial Statement, the Public Staff's Initial Statement, and the entire record herein.

Summary of the Comments

Duke's Initial Statement notes that DEC's and DEP's Schedule PP rates, as the Commission approved in the 2020 Sub 167 proceeding and prior proceedings, include avoided energy credits that vary depending on whether the QF is interconnected with and delivering energy into the transmission or distribution system. In the past, Duke explains, DEC and DEP have consistently supported offering different avoided energy credits based on the point of interconnection to DEC's and DEP's systems, because this approach more accurately reflected differences in DEC's or DEP's actual avoided costs due to differences in avoided energy line losses for transmission level and distribution level QFs. Duke Initial Statement at 27.

In the 2018 Sub 158 proceeding the Commission approved DEC's and DEP's inclusion of a line loss adjustment in Schedule PP and further directed the Utilities to continue to "study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the 2020 Sub 167 avoided cost proceeding." 2018 Sub 158 Order at 36. Duke Initial Statement at 28.

Duke's Initial Statement notes that in the 2020 Sub 167 proceeding, DEC and DEP again conducted an analysis to determine the number of substations that were then currently experiencing or expected soon to experience significant backfeed because of the recent growth in utility-scale QF capacity. Based upon this analysis, Duke explains that it determined that it was appropriate to retain a line loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP. For proposed distribution-connected QFs not eligible for Schedule PP, Duke explains, it committed to continue investigating whether the QF's energy output would continue to backfeed at the substation and inject energy onto the transmission system. The Sub 167 Order approved DEC's and DEP's proposed distribution line loss adder for standard offer-eligible QFs contracting under Schedule PP. 2020 Sub 167 Order at 35, 59-60 (Ordering Paragraphs 5-6). The Commission, at the Public Staff's recommendation, directed DEC and DEP to evaluate and report on: (1) any geographical concentrations of back-feeding substations; and (2) whether a rate design with or without a line loss adder based on the amount of back-feeding at a substation would be appropriate to provide a more accurate avoided cost rate to QFs regarding the value of energy at the selected station. *Id.* at 35. Duke explains that the Commission further directed DEC and DEP to discuss these issues with the Public Staff and other stakeholders prior to filing in the 2021 avoided cost rate proceeding. *Id.* at 29.

Duke's Initial Statement states that prior to its filing in this proceeding Duke evaluated the geographic concentration of backfeeding substations and found that both DEC and DEP are currently experiencing increasing levels of backflow into the transmission system due to increasing QF solar generation. *Id.* Duke states that its updated analysis showed that for DEP, 106 out of 407 substation banks, or 26%, are backfeeding into the transmission system due to distribution-connected generation. For DEC, Duke states that the percentage of substation banks experiencing backfeed due to distribution-connected projects continues to be significantly less – only 48 out of 1048 banks analyzed, or 4.6%, are backfeeding. *Id.*

Duke's Initial Statement includes a map showing the concentrated nature of QF solar development in more rural areas, especially in the DEP eastern North Carolina service territory. However, Duke explains that distribution-connected QFs continue to not be as geographically concentrated in DEC or DEP territory as compared to DENC. *Id.* at 30. While a certain level of backflow into the transmission system is not likely to offset the line loss benefits of distributed generation, Duke states that its analysis suggests that additional generation will start to increase substation losses in the future. Specifically, Duke states that the near-term contribution or impact of adding one or more 1 MW standard offer QFs on substation backflow would not be sufficiently substantial to offset the line loss benefit, while more significant concentrations of larger distribution-connected QFs may increase backflow to the point where the line loss adder is no longer appropriate. *Id*. at 29.

Based upon Duke's most recent analysis, both DEC and DEP propose to maintain the line loss adder for standard offer-eligible QFs contracting under Schedule PP at this time. Duke states that for QFs greater than 1 MW that are not eligible for the standard offer, which could backflow a more significant amount of energy into the transmission system, Duke proposes to assess the individual characteristics of the QF and address through negotiation of the PPA whether retaining or eliminating the line loss adjustment from the avoided energy value is appropriate on a case-by-case basis. Specifically, Duke indicates that DEC and DEP would assess the amount of potential backflow from distribution-connected QFs greater than 1 MW against the following criteria to determine if the line loss adder is appropriate: (1) whether the substation bank that serves the distribution point-of-interconnection has distributed energy resources (DER) backflow of greater than or equal to 50%; or (2) whether the addition of the QF would cause the DER backflow to become greater than or equal to 50%. If these criteria are met, Duke states that the QF will receive the transmission rates that exclude marginal loss factors for capacity and energy. *Id.*

In its Initial Comments, the Public Staff states that it believes Duke's continued inclusion of the line loss adder for the standard offer avoided cost rate is reasonable given the current subscription ratio of distribution connected generation to Duke's distribution system. The Public Staff further states that Duke's proposed method to evaluate the potential for backflow from distribution-connected QFs greater than 1 MW and whether to include the line loss adder is objective and reasonable. Public Staff Initial Statement at 16-17.

Discussion and Conclusions

Based upon the foregoing and the entire record, the Commission finds Duke's inclusion of the line loss adders for the standard avoided cost rates to be reasonable and appropriate. The Commission further approves Duke's proposed method for evaluating the potential for backflow from distribution-connected QFs greater than one MW to be reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

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

Summary of the Comments

In its Initial Statement, DENC states that in the Sub 148 Order, the Commission approved DENC's proposal to eliminate the 3% line loss adder, and that in the Sub 158 Order, the Commission found that it was appropriate that DENC continue not to include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network. DENC notes that prior to its initial filing the in Sub 167 proceeding, DENC updated its evaluation of the amount of backflow on the North Carolina portion of its service area in the Sub 167 Avoided Cost Case (2020 Backflow Study).[4] DENC reports that the 2020 Backflow Study showed that the number of transformers experiencing

[4] DENC notes that it did not include the 2020 Backflow Study in its Sub 167 Initial Statement due to the streamlined nature of that proceeding.

backflow had continued to increase since the Sub 158 Avoided Cost Case: of 41 transformers with connected distributed solar, the study showed 24 realizing consistent backflow (58.5%), an increase from the 16 out of 38 transformers (42%) consistently experiencing backflow in the 2018 study conducted for the Sub 158 Avoided Cost Case. DENC Initial Statement at 10-11.

DENC's Initial Statement presents DENC's updated line loss analysis in Exhibit DENC-12, which shows that, compared to the 2018 Backflow Study and the 2020 Backflow Study, the number of transformers experiencing backflow has continued to increase as more Solar DG has become operational. Of the 42 transformers with Solar DG connected, 34 transformers have consistent backflow. Only 3 transformers have consistent positive flow as compared to 4 transformers in the 2018 and 2020 studies, which indicates that only 3 of the 42 transformers still have capacity for additional load reduction capability. *Id*. at 11-12, Exhibit DENC-12.

In its Initial Statement the Public Staff supports DENC's continuing to exclude a line loss adder from the standard offer avoided cost rate given the high backflow at DENC's substations. Public Staff Initial Comments at 16. No other parties commented on DENC's removal of the line loss adder.

Discussion and Conclusions

Based on the foregoing and the entire record herein, the Commission determines that it is appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer for the purposes of this streamlined proceeding. DENC's updated line loss study demonstrates a continued increase in the number of transformers on the North Carolina portion of DENC's system experiencing consistent backflow and a decrease in the number of transformers with capacity for additional load reduction capability, and predicts this pattern increasing over time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, the Public Staff's Initial Statement, and the Initial Comments of CCEBA/NCSEA, and SACE, and the entire record herein.

Summary of the Comments

In its Initial Statement, Duke notes that the avoided costs and the potential for increased ancillary service costs associated with integrating incremental solar generation has been a significant issue in recent avoided cost proceedings in North Carolina. Duke explains that it first proposed an integration services charge in the 2018 Sub 158 proceeding in response to the Commission's 2016 Sub 148 Order. Duke explains that it calculated these charges based upon a solar integration cost study by Astrapé Consulting (2018 Astrapé SISC Study) and designed them to quantify the impact on operating reserves, or the increased generation ancillary service requirements, necessary to integrate new variable and non-dispatchable solar capacity into the DEC and DEP systems. Duke Initial Statement at 31. Duke notes that the 2018 Astrapé SISC Study showed that, as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases. Duke Initial Statement at 32.

In the 2018 Sub 158 Order, the Commission approved the inclusion of Duke's proposed solar integration services charge values, which the 2018 Astrapé Study supported, as a component of each utility's avoided energy costs. *Id.* Duke explains that the 2018 Sub 158 Order also directed DEC and DEP to undertake an independent technical review of the 2018 Astrapé Study to inform future biennial avoided cost proceedings about DEC's and DEP's ancillary services costs associated with integrating intermittent, non-dispatchable generation. As detailed in each of the Sub 158 Additional Issues 45-Day progress reports Duke filed with the Commission in the Sub 167 docket, Duke initiated the independent technical review of the 2018 Astrapé Study's methodology and modeling used for system simulations. Duke explains that Brattle Consulting led the review as principal consultant with the involvement of technical experts from three national renewable energy laboratories (the Technical Review Committee) as well as participation by the Public Staff and the South Carolina Office of Regulatory Staff as regulatory observers.[5] Taking into account input from the TRC and at Duke's direction, Astrapé Consulting developed an updated 2021 SISC Study that incorporates the TRC Report's findings and updates its modeling and analysis of the integration costs associated with integrating incremental solar into the DEC and DEP systems.[6] Duke explains that based upon Astrapé's updated analysis, DEC and DEP have incorporated solar integration cost decrements of $1.05 per MWh (DEC) and $2.26 per MWh (DEP) into the uncontrolled solar avoided energy rates. *Id.* at 33-34.

In the TRC Report provided as an exhibit to Duke's Initial Statement, the TRC addressed the methodology and inputs of the SISC and found that the 2021 Astrape Report focuses on adding load following reserves to maintain the intra-hour reliability level that the Duke systems are able to achieve in the absence of solar generation. The TRC Report determined this methodology to be a less stringent criterion than the absolute level of loss of load events (LOLE) that was used in the 2018 study. In addition, the current study increases load following reserves on a monthly basis and only during the hours of the day when solar-related flexibility violations are likely to occur each month, which is a different approach than that employed in the 2018 study, which increased reserve requirements by the same amount for all hours of the year. Maintaining no-solar reliability levels and targeting the load following reserves additions to the months and time of day when needed reduces integration costs. The TRC noted that the reserve levels might be adjusted further depending on each day's volatility forecast. For example, required reserves could be higher on partially cloudy days when volatility is the greatest. However, the TRC stated that this forecast-based approach is still in the research stages and, thus,

[5] Duke attaches a copy of the TRC Report as DEC/DEP Exhibit 10 to Duke Initial Statement.

[6] Duke attaches the 2021 Astrapé SISC Study as DEC/DEP Exhibit 11 to the Duke Initial Statement.

not standard practice among system operators. Therefore, the TRC did not believe it necessary to include it in this study of the SISC

In its Initial Statement, the Public Staff states that it reviewed both the TRC Report and the 2021 Astrapé Study. The Public Staff notes that in addition to addressing methodology and inputs, the TRC also addressed matters raised by intervenors in the Sub 158 proceeding and submitted to the TRC on March 30, 2021, by the Southern Environmental Law Center on behalf of SACE, NCSEA, and CCEBA. Public Staff Initial Statement at 20. According to the Public Staff, the TRC Report provides an in-depth discussion of the specific issues discussed during the TRC meetings and addresses how each recommendation from the TRC is incorporated into the 2021 Astrapé Study. Overall, the Public Staff notes that the TRC found the estimated cost of reserves to be reasonable given the size of DEC and DEP relative to PJM Interconnection, L.L.C. and given the relative inflexibility of Duke's generation fleet. Public Staff Initial Statement at 20-21.

The Public Staff states that DEC proposes a SISC of $1.05 per MWh and DEP proposes a SISC of $2.26 per MWh, and that these proposed figures represent a 5% decrease from the SISCs approved in the Sub 158 and Sub 167 proceedings Public Staff Initial Statement at 45. The Public Staff additionally highlights several changes to the SISC methodology adopted based upon the input of the TRC and stakeholders. First, the Public Staff notes that a major criticism of Duke's proposed SISC methodology in the Sub 158 proceeding was that DEC and DEP were modeled separately. Because the Joint Dispatch Agreement (JDA) allows DEC and DEP to share load following reserves at least cost in the event of intra-hour net load variations, the Public Staff explains that the 2021 Astrapé SISC Report includes a SISC calculated under the JDA assumptions at the TRC's recommendation. The Public Staff states that it finds the SISC derived under the JDA assumptions to be reasonable and appropriate, and it supports Duke's proposal to utilize the SISC with those assumptions. Public Staff Initial Statement at 21-22.

Similarly, the Public Staff notes that Astrapé's use of the Loss of Load Expectation (LOLE) flexibility standard (which approximated NERC reliability standards) was another contested issue in the Sub 158 proceeding. The Public Staff notes that the 2021 Astrapé SISC Report focuses on returning the system to pre-solar levels of reliability rather than on incorporating the NERC reliability standards into the model. The Public Staff agrees with this approach and notes that the TRC also supports the approach. *Id.* at 22.

Next, the Public Staff notes that the 2021 Astrapé SISC Study employed a targeted approach to adding load following reserves, adding reserves when they are most likely to be needed (i.e., in hours of high solar volatility). The Public Staff agrees with this approach and notes that the TRC also supports the change, finding that adding load following reserves only when solar volatility is a factor better represents actual system conditions and operations. *Id.* at 22-23.

Finally, the Public Staff notes that the TRC considered whether it was appropriate to include the effects of the proposed Southeastern Energy Exchange Market (SEEM) in calculating the SISC. According to the Public Staff, the TRC found that incorporating

SEEM would be at least partially speculative since the design, implementation, and actual operations of the SEEM are still uncertain. Accordingly, the Public Staff recommends that Duke consider the effect of the SEEM on the calculation of the SISC in any avoided cost filings that occur six months or more after SEEM operations commence. *Id*. at 24.

The Public Staff recommends in the interest of transparency around SISC avoidance that the Commission 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 future avoided cost filings. In addition, the Public Staff recommends that the Commission 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 credits issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC. *Id*. at 46.

In its Initial Comments, SACE states that it believes that the TRC process had been productive, pointing out that the TRC discussed and incorporated several concerns that SACE raised. SACE Initial Comments 23. SACE recommends building on the success of this approach and requiring third-party independent technical review, informed by stakeholder input, of Duke's analyses in the avoided cost and other proceedings in the future. *Id*. SACE states there were three errors in the proposed methodology, the TRC's findings, and the updated SISC methodology and rate inputs, as calculated in the 2021 Astrapé SISC Study. *Id.* First, the 2021 Astrapé Study assumed that solar load-following reserves are required during multiple hours during which there is no solar generation. *Id.* Second, the "combined case" designed to approximate the functioning of the JDA failed to account for the reduction in the amount of solar load-following reserves that are required under actual JDA operations, which allow "netting" the DEC and DEP systems' dispatch needs to meet real-time balancing requirements. *Id.* at 24. Third, the 2021 Astrapé Study applied a five-minute "flexibility violation" metric that is more stringent than the 30-minute balancing required by the NERC reliability standards. *Id.* SACE recommends that the Commission require Duke to revise the 2021 Astrapé Study to correct these errors. *Id.* at 25.

In their Joint Initial Comments, CCEBA and NCSEA object to the SISC on the grounds that under Session Law 2021-165 and the resulting Carbon Plan variable clean-energy resources must be the norm, not the exception, and Duke must plan and operate its system to optimally integrate large quantities of interconnected clean energy resources. CCEBA and NCSEA Joint Initial Comments 3. CCEBA and NCSEA also agree that the SISC is flawed in the ways SACE identified. *Id*. at 4.

In its Reply Comments, Duke states that the 2021 Astrapé SISC Study considered and tested Duke's load following requirements iteratively to determine the least cost way to resolve flexibility excursions and highlights a number of improvements to the 2021 Astrapé SISC Study over the 2018 study that were recognized by the TRC. DEC/DEP Reply Comments at 40. Duke also addresses each of SACE's three criticisms.

First, Duke notes that the 2021 Astrapé SISC Study appropriately considered and tested Duke's solar incremental load-following reserve requirements iteratively to determine the least cost way to resolve flexibility excursions. According to Duke, Astrapé examined the 12x24 flexibility excursions from the cases with solar and added reserves to remove the aforementioned excursions. Based on this assessment, Astrapé removed some of the flexibility excursions in the pre-solar and post-solar hours. Using this methodology, Duke explains that the overall excursions are still reduced to the level of the no solar Base Case, and the TRC found Astrapé's approach to be a "significant improvement" over the approach used in the previous study.

Second, Duke asserts that SACE's assertion that "the JDA nets the DEC and DEP systems' dispatch needs to meet real-time balancing requirements" is an not an accurate representation of its obligation under the JDA. According to Duke, while the JDA allows economic exchanges to reduce the costs of additional load following requirements, each Balancing Authority (BA) must continue to plan for and maintain its own operating reserves. *See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct,* Docket Nos. E-2, Sub 998 and E-7, Sub 986, at Appendix A, Regulatory Conditions Section 4.1 (June 29, 2012). Duke asserts that it used input from both the TRC and Duke subject matter experts to ensure its model accurately reflected the true operation of the JDA in Astrapé's "combined case." Duke Reply Comments at 41. Duke notes that the TRC found this methodology to be appropriate to ensure resources in DEC and DEP are jointly committed and dispatched and that the 2021 Astrapé SISC Study models the JDA through lower fuel and operations costs, while ensuring each BA maintains its respective operating reserves.

Finally, Duke explains that the TRC accepted the 2021 Astrapé Study's modeling approach to address flexibility violations and that it is not unreasonably stringent. In particular, Duke notes that the TRC supported Astrapé's approach to assessing flexibility violations, finding that increasing the length of the flexibility violations to ten (10) minutes would result in higher rather than lower integration costs. DEC/DEP Exhibit 10. In direct contrast to SACE's contention, the TRC found that the five-minute flexibility violation "results in a lower SISC relative to using a longer flexibility violation." *Id.* As the TRC found, "adjusting the modeling assumptions to reduce the level of reliability to exactly the amount needed to avoid NERC standards implies eliminating any potential reliability cushion that has historically been provided to customers and giving all the benefit of eliminating that cushion entirely to solar resources." *Id.* Accordingly, Duke recommends that the Commission reject SACE's recommendation to modify the SISC methodology.

<u>Discussion and Conclusions</u>

In the 2018 Sub 158 Order, the Commission directed Duke to assemble a technical review committee to provide a review of the Astrapé Study. 2018 Sub 158 Order at 95. In doing so, the Commission further directed that the review committee should be comprised of individuals not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke or its affiliates is a member, including at least one person employed by the National Laboratories with relevant experience and expertise. With respect to scope, the

Commission directed that the purpose of the work was to provide an in-depth review of the study methodology and the model used for system simulations. *Id*. The Commission has been following the work of the TRC through reports Duke has filed documenting the progress on this issue, among others. Based on its review of both the 2021 Astrapé SISC Report and the TRC Report, in addition to the comments and filings of parties to this docket, the Commission finds that the 2021 Astrapé SISC Report contains several improvements over the 2018 Astrapé SISC Study, and the Commission agrees with the TRC and the Public Staff that the 2021 Astrapé Study reasonably quantified solar integration costs for DEC and DEP. The Commission commends Duke and the TRC for the work undertaken to comply with this directive.

The Commission notes the TRC's statement that Duke's reserve levels might be able to be adjusted further in the future depending on each day's volatility forecast, and the Commission directs Duke to address whether its reserve levels might be further refined in the next avoided cost proceeding.

Accordingly, the Commission approves Duke's SISC as presented in the 2021 Astrapé Report and declines to accept the critiques presented by SACE. The Commission further directs Duke to continue to evaluate the appropriate method for quantifying integration costs based on the method supported by the TRC and used to develop the 2021 Astrapé SISC Report and that the Commission determines to be reasonable in this proceeding. The Commission agrees that Duke should consider the effect of the SEEM, if any, on the calculation of the SISC in future avoided cost proceedings.

The Commission also agrees with the Public Staff's recommendation about the need for transparency around SISC avoidance. The Commission therefore directs 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 future avoided cost filings, and also directs Duke to 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.

Based upon the foregoing and the entire record, the Commission finds the solar integration cost decrements of $1.05 per MWh (DEC) and $2.26 per MWh (DEP) to be reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

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

Summary of the Comments

In its Initial Statement, DENC proposes an update to the re-dispatch charge (RDC) to reflect the costs of the integration of intermittent, non-dispatchable QFs on its system. DENC states that, as explained in the 2018 Avoided Cost Case, it defines re-dispatch generation costs as additional fuel and purchased energy costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. DENC explains that as more intermittent generation like solar PV or wind is added to the grid, the level of uncertainty about re-dispatch costs increases due to unpredictable cloud cover or changes in wind speed. To assess the re-dispatch costs, DENC used the Aurora planning model with a simulation topology of the Eastern Interconnection to capture the DOM Zone hourly prices interactively as well as the potential system cost impacts from intermittent resources outside DENC's service territory. DENC presented this approach as an improvement over the re-dispatch analysis conducted in the 2018 Avoided Cost Case as it models solar generation across a broader geographical region, models the entire eastern interconnect, and performs a more robust simulation.

DENC explains further that in the 2021 IRP Update, it took a chronological approach to modeling the re-dispatch cost, by utilizing one build plan from the 2020 IRP (Alternative Plan D) and studying 16 years chosen based on when resources were introduced or retired in the 2020 IRP Alternative Plan D 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, it performed an additional 200 simulations but applied different hourly renewable profiles from the National Renewable Energy Laboratory's (NREL's) historical weather pattern studies to reoptimize the system cost.

DENC states that it compared the total system cost for each simulation 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 2021 IRP Update. DENC calculated the average RDC for the ten years 2022-2031 to be $1.87/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 14-15.

Based on its review the Public Staff states that it generally finds DENC's revised methodology to be an improvement over the methodology the Commission approved in the Sub 158 Avoided Cost Case and used in the Sub 167 Avoided Cost Case. The Public Staff explains that the prior methodology focused only on a single year, running multiple PROMOD runs with varying solar output profiles at specific generation sites, to calculate the RDC. The new model, in contrast, uses Alternative Plan D from DENC's 2020 IRP to calculate the RDC in each future year by calculating the cost difference between "day ahead" and "real time" model runs, creating a RDC cost curve using the Aurora model. Public Staff Initial Statement at 49-50.

SACE notes that DENC's RDC has increased from $0.78/MWh in the Sub 158 and Sub 167 Avoided Cost Cases to $1.87/MWh in the current proceeding. SACE asserts that the methodology DENC used to develop the RDC is flawed and does not reflect the actual solar integration costs and may be too high. Exhibit B to SACE's comments (Kirby Report) states that the basic methodology of comparing production cost modeling results from cases without and with solar generation is reasonable but argues that DENC should have time-synchronized solar generation with power system data in order to produce accurate results. The Kirby Report also states that the historic solar data used to derive the RDC comes from twenty-two locations, all but three of which are outside of North Carolina. SACE Initial Comments at 38-41, Exhibit B.

SACE also contends that the increase in DENC's RDC appears to be based at least in part on an error. SACE claims that as more intermittent generation like solar PV or wind is added to the grid, "geographic smoothing" should smooth out the overall variability among renewable generation as generation is added in geographically distinct locations. *Id*. at 39. CCEBA and NCSEA support SACE's positions regarding DENC's RDC. CCEBA/NCSEA Initial Comments at 19.

In its Reply Comments, DENC explains that it considers the RDC methodology to be a reasonable approximation of the re-dispatch costs that result from increased intermittent renewables on its system. DENC points out that SACE's critiques of the methodology overstate the relationship between solar generation output and system load, mischaracterize the impact of using a narrower geographic selection of locations, and appear to mistakenly assert that DENC applied assumptions about geographic diversity within the Aurora model when it did not. DENC Reply Comments at 15.

DENC also explains that it modeled 22 locations across a broad geographic region to represent the entire PJM RTO BA and that including three locations in North Carolina is appropriate as the DENC service area is geographically compact. DENC also indicates that the addition of more locations within North Carolina would not have significant impacts on the model results. *Id.* at 16.

Finally, DENC explains that its statements regarding the increase in the level of uncertainty about re-dispatch increasing as more intermittent generation like solar PV or wind is added to the grid due to unpredictable cloud cover or changes in wind speed was not in reference to geographic smoothing. DENC does not expect geographic diversity to increase re-dispatch costs. DENC clarifies that it did not interpret the effect of geographic diversity to be to cause increased costs or configure the model to increase costs due to geographic diversity, but rather modeled the units and load on its system without applying any inputs regarding diversity at all, and any benefits due to diversity would have showed up as an output of the model. *Id.*

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 methodology for calculating the RDC is an improvement from the method for calculating the RDC is an improvement from the method DENC used in the Sub 158 and Sub 167 Avoided Cost Cases and is reasonable for use in this proceeding. The Commission agrees with DENC and the Public Staff that the new method performs a more robust simulation by modeling solar generation across a broader geographical region for sixteen years rather than the prior method's more limited geographic scope for one year. The Commission also agrees with DENC that it was appropriate to calculate the RDC with 3 of the 22 locations modeled being in North Carolina, as that is more representative of DENC's compact North Carolina service territory.

For the reasons DENC presents in its Reply Comments, the Commission is not persuaded by SACE's comments that DENC inappropriately considered the characteristics of QF power supplies, or that DENC inappropriately applied a presumption against geographic smoothing in its modeling. DENC has explained in detail the derivation of the updated RDC, as well the improvements to the calculation method. The Commission concludes that the updated RDC is reasonable and is approved as it will more accurately reflect DENC's actual avoided costs, as required by PURPA and Section 62156.

The Commission therefore concludes that it is appropriate for DENC to apply an RDC of $1.87/MWh for purposes of Schedule 19FP in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, the Initial Comments of CCEBA/NCSEA and SACE, and the entire record herein.

Summary of the Comments

Duke's Initial Statement explains that it considered the potential for QFs to provide positive ancillary services pursuant to the Commission's direction in the Sub 158 Order. Specifically, Duke assessed changes to system operations necessary to incorporate third-party QF ancillary services while maintaining system reliability. Duke states that it also analyzed approaches in other states and engaged with the Public Staff and interested stakeholders on this issue. Duke Initial Statement at 34.

Duke asserts in its Initial Statement that a fundamental aspect of ancillary services is that system operators must have operational control over the assets to dispatch them quickly as need arises, and because DEC and DEP system operators do not have such control over third-party QF resources, QFs currently do not have the ability to provide positive ancillary services benefits at a lower cost than the utilities' own resources. Further, Duke argues that transitioning the BAs' modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would require a fundamental change in grid operation, along with major technical and financial investments. *Id*. at 36.

Finally, Duke argues in its Initial Statement that the “must-take” PURPA framework is not compatible with the concept of QFs providing positive ancillary services. Duke notes that the “must-take” payment structure assumes that QFs will provide all of their energy and capacity to the purchasing utility, where providing ancillary services to the utility would require QFs to produce less than their maximum energy and capacity. Duke additionally argues that integration of QFs has historically increased the need for ancillaries on the system as solar QF output is variable, intermittent, and dependent on somewhat unpredictable environmental factors.

For these reasons, Duke concludes that a QF selling “must take” energy under PURPA cannot provide incremental positive ancillary services value under current system operations. *Id*.

In its Initial Statement, DENC notes that behind the meter resources do not have the capability to effectively follow direct signals from PJM or relayed instructions by DENC. As a result, such resources are not eligible to participate in ancillary service markets for the benefit of system customers. *Id*. at 13.

In its Initial Comments, the Public Staff states that it had numerous discussions with intervenors and Duke to discuss what ancillary services QFs might provide and whether it is reasonable and cost effective for Duke to procure these services from QFs within the context of PURPA. In addition, the Public Staff notes that it is not aware of any other regulated utility in the country, operating outside of an RTO or Independent System Operator (ISO), that procures ancillary services from a third-party power supplier. The Public Staff notes that while PURPA’s mandatory purchase obligation does not extend to ancillary services, it also does not prohibit the procurement of ancillary services from QFs. Public Staff Initial Statement at 17.

The Public Staff states that as DEC and DEP procure additional renewable generation to comply with the Carbon Plan, inverter-based-resources (IBRs) such as solar PV may provide some ancillary services at least cost – spinning reserve, frequency regulation, and Volt-VAR support. *Id*. However, the Public Staff also acknowledges concerns with implementation of such a program particularly given the relatively small amount of ancillary services required at any given time. In addition, the Public Staff believes it is unlikely a QF would choose to provide ancillary services during most times of the year since QFs must hold back energy and capacity to maintain the ability to ramp up to provide ancillary services, and the rates for ancillary services purchased by RTOs and ISOs are generally much lower than PURPA rates for energy and capacity. *Id*. at 18-19.

Given these uncertainties, the Public Staff in its Initial Statement asks for feedback from Duke, DENC, and other intervenors, on the potential benefits of initiating a proceeding to investigate: (1) the ability of QFs to provide ancillary services; (2) potential benefits, if any, to customers, of QFs providing ancillary services; and (3) potentially establishing a pilot program to procure a small amount of ancillary services from IBRs. *Id*. at 19.

CCEBA/NCSEA and SACE each argue that QFs should be compensated for the provision of ancillary services. First, CCEBA/NCSEA argue that Duke's characterization of operational control of QFs is incomplete, and that the changes necessary to facilitate the provision of ancillary services from QFs are easily attainable. In CCEBA/NCSEA's view, many existing QFs may already be equipped with automatic generation control (AGC) capability that would allow them to provide ancillary services already or with limited modification. CCEBA/NCSEA believe that existing QFs could upgrade their systems to allow them to provide ancillary services without substantial cost and that benefits to the grid outweigh the costs to facilitate their availability. CCEBA/NCSEA Initial Comments at 6-7. In addition, CCEBA/NCSEA argue that modifications to QF operations could incentivize the provision of ancillary services, and that QFs willing to amend their PPAs to sell less than their full output to DEC and DEP and should have the option to do so. CCEBA/NCSEA Initial Comments at 9-10.

CCEBA/NCSEA next state that QFs already provide a type of ancillary service, reactive power, to DEC and DEP without compensation. In particular, CCEBA/NCSEA notes that the Interconnection Agreement (IA) between DEC/DEP and QFs requires Interconnection Customers to maintain a composite power delivery at a prescribed power factor, for which they are not compensated. CCEBA/NCSEA also allege that DEC and DEP provide reactive power from their own renewable facilities in other jurisdictions, referencing comments Duke filed in FERC's ongoing proposed rulemaking on reactive power compensation. *Id*. at 7-8. CCEBA/NCSEA argue that the peaker method does not incorporate the provision of and compensation for ancillary services. According to CCEBA/NCSEA, neither avoided energy nor avoided capacity costs under North Carolina's peaker methodology expressly include ancillary services. *Id.* at 11-12.

For all of these reasons, CCEBA/NCSEA recommend that the Commission initiate a stakeholder proceeding to evaluate how new and existing solar and solar plus storage facilities can provide and receive compensation for ancillary services. In particular, CCEBA/NCSEA note that stakeholders could collaborate to devise a contract and commercial structure for new solar and solar plus storage that allows for QF provision of and compensation for ancillary services. CCEBA/NCSEA point to a dispatchable PPA as one option to allow a solar generator to provide ancillary services to the utility for compensation. *Id.* at 15-16.

SACE reiterates and adopts CCEBA/NCSEA's position that QFs already provide positive ancillary services and could provide more. In addition, SACE argues that QFs are entitled to compensation for ancillary services under PURPA. SACE Initial Comments at 25.

In its Reply Comments, Duke argues that its avoided cost rates fully compensate QFs for delivering energy and capacity. Specifically, Duke asserts that the peaker method inherently provides the operational capacity value of the avoided CT unit, which would include any value of ancillary services the hypothetical CT is capable of providing. Duke asserts that the theory of peaker method is that while there is not a discrete adjustment or “adder” for operating the avoided CT unit to provide ancillary services, avoiding the capital and operating cost of the peaker unit and marginal running costs of the system fully represents the capacity and energy value that can be avoided by purchasing power from a QF. Duke further points out that, under PURPA, utilities may not lawfully pay QFs at rates above the utility’s full avoided capacity and energy costs. Accordingly, while a QF could technically enter into some agreement to provide ancillary services, such costs are only recoverable under PURPA to the extent they are actually avoided. Duke further comments that because the DEC and DEP systems have no present incremental need for ancillary services, payment to QFs for ancillary services would not be appropriate under PURPA. Duke Reply Comments at 25-26.

Duke further argues that no new Commission action or proceeding is currently necessary to further evaluate procuring ancillary services from. In support of this position, Duke’s Reply Comments reiterate that transitioning DEC’s and DEP’s modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would create costs rather than avoid costs and would require a fundamental change in how the grid is operated, along with major technical and financial investments. *Id*. at 31. Duke further notes that the only way to provide regulation up capability would be to curtail solar across the day and then release some of that curtailment to provide upward regulation when needed. According to Duke, no QFs have opted to mitigate their output to avoid the SISC, indicating that the ancillaries quantified to date in the SISC are not of high enough value to forego the energy value. *Id*. at 33.

In its Reply Comments, DENC agrees with the Public Staff that PURPA does not require utilities to purchase ancillary services from QFs, and further clarifies that PURPA does not require utilities to provide QFs with access to ancillary services markets. DENC states that with respect to PJM, for access to spinning reserves, frequency control, and voltage support ancillary compensation is available to QFs through direct market participation, but DENC is not required to achieve market participation on behalf of or for a QF. DENC states that ancillary services should not be part of its avoided cost rates because DENC’s customers already pay for these ancillary services obtained by PJM, and the PJM market structure does not allow for DENC’s customers to avoid any ancillary costs due to a QF providing an ancillary service, even assuming that the QF had the technical ability to provide the service. DENC explains that requiring payment for any ancillary services that a QF were able to provide would therefore contradict the fundamental principle of PURPA that the utility cannot be required to pay more than its avoided cost for QF output. DENC Reply Comments at 24-25.

In their Joint Reply Comments, CCEBA/NCSEA argue that the Commission should require Duke to provide detailed information on how DEC and DEP procure and compensate ancillary services. CCEBA/NCSEA then reiterate their recommendation for a stakeholder process to discuss the technical, contractual, and legal questions related to QFs’ ability to provide and be compensated for ancillary services and, further, express support for the pilot program proposed by the Public Staff. CCEBA/NCSEA Reply

Comments at 7. SACE's Reply Comments likewise support the stakeholder proceeding and pilot program the Public Staff proposes, arguing that all interested parties would benefit from a more detailed understanding of the technical ability of QFs to provide ancillary services and the associated costs. SACE Reply Comments at 4-5.

The Public Staff's Reply Comments state that the issue of ancillary services has expanded beyond a strictly avoided cost issue, particularly as procurement of IBRs is increasingly occurring outside of PURPA contracts. Accordingly, the Public Staff recommends that the Commission open a separate docket to solicit comments specifically related to the proposed pilot or, more broadly, utilization of IBRs to provide ancillary services. Public Staff Reply Comments at 4-5. To support its proposal for a new docket, the Public Staff notes that the energy landscape in North Carolina is shifting, with fewer third-party projects selling power through standard offer and negotiated contracts under PURPA. Instead, large-scale competitive procurements for renewable energy are increasingly responsible for much of the new solar interconnected to Duke's grid. Accordingly, to minimize the amount of regulatory attention that a pilot program would divert, the Public Staff suggests that it may be more beneficial for Duke and stakeholders to focus on potential revisions to future competitive procurements triggered by need identified within the Carbon Plan. *Id*. at 6-7.

Discussion and Conclusions

In response to comments of the Public Staff, the Commission directed the utilities to address the potential for QFs to provide ancillary services and appropriate compensation in the Commission's Sub 158 Order. After investigating the issue and engaging with the Public Staff and stakeholders as described in its Initial Statement, Duke concludes that QFs selling energy and capacity under PURPA cannot provide incremental positive ancillary services value under current system operations. The Public Staff, for its part, recommends that the Commission open a new docket for the purpose of further investigating ancillary services, including considering the merits of a potential pilot program and potential revisions to future competitive procurements to facilitate QF provision of ancillary services. CCEBA/NCSEA and SACE each argue that QFs have the capacity to provide valuable ancillary services and should be compensated for doing so now and support the Public Staff's stakeholder proceeding proposal. While there is disagreement among the utilities and the intervenors regarding compensation for ancillary services, there appears to be agreement that further investigation into ancillary services is warranted.

The Commission agrees with the Public Staff that the energy landscape in North Carolina is changing in a manner that results in fewer QFs selling power through standard offer PPAs while participation in competitive procurements is increasing. In addition, it is likely that Duke will be procuring new solar resources and solar plus storage resources in competitive procurements resulting from the Carbon Plan. The Commission further agrees with the Public Staff that studying the ability of IBRs to provide ancillary services is worthwhile. The Commission directs Duke to conduct a preliminary investigatory study of the operating characteristics of IBRs at certain of its own IBR facilities to understand which ancillary services each resource or combination of resources can provide. Duke shall file a report on its findings with the Commission in a new docket on or before August 1, 2023. In the report, Duke shall also address the potential benefits, if any, to customers, of QFs providing ancillary services and whether a pilot program would be worthwhile. Duke shall share the results of the study with the Public Staff and other interested stakeholders prior to filing the report

The Commission further agrees with DENC that due to DENC's membership in PJM and the market rules and processes already established in that RTO for the provision of and compensation for ancillary services, it would not be appropriate or reasonable to include DENC in any further evaluation of the potential for QFs to provide and receive compensation for ancillary services.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

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

Summary of the Comments

As directed by the Commission in the Sub 158 Order, DENC proposed in the Sub 167 proceeding that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD). DENC defined an ESD as a component of a QF facility that uses energy storage technology, including but not limited to battery storage. DENC proposed to calculate the reduction in variability as the percent reduction in variability from a case without storage to a case with storage. The output for the case without storage will be the actual metered output of the facility excluding the impact of storage, and the output for the case with storage will be the actual metered output for the facility including the impact of storage. DENC noted that determining the impact of storage will require that the storage device is separately metered. DENC explained that for a QF to be eligible for the RDC cost reduction, it must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date (COD) and then for subsequent contract years, the QF may update the forecast on or before 90 days before the start of every calendar year of the contract. If no updated forecast is provided, DENC would use the previously provided forecast to calculate the RDC reduction credit. Every April, DENC would calculate the re-dispatch cost reduction using the prior calendar year forecast and metered data. DENC would provide the RDC reduction as a line item credit with the first payment following the April calculation. DENC Initial Statement at 15-16.

In the Sub 167 Order, the Commission concluded that DENC's proposed RDC avoidance protocol was appropriate and that DENC had complied with the Sub 158 Order directive to file a protocol for the avoidance of the RDC. The Commission found it reasonable to reduce the RDC to the extent a QF reduces the variability of its output using an ESD and that the protocol is a reasonable proxy for estimating that reduction in costs. The Commission also concluded that, if any controlled solar generator (CSG) seeks to avail themselves of the RDC avoidance protocol, it may be helpful for purposes of evaluating the results of the protocol for DENC to monitor and provide information regarding the types of forecasts, dispatch behavior, and solar volatility of CSGs that avail themselves of the RDC avoidance protocol, as requested by the Public Staff. The Commission encouraged DENC and the Public Staff to continue to discuss this information and directed DENC to address its proposed monitoring and reporting of this information in its initial filing in this proceeding. *Id.* at 17.

DENC explains in its Initial Statement that it plans to maintain the RDC avoidance protocol as the Commission approved in the Sub 167 Order for the purposes of this proceeding. DENC notes that regarding the information that it agreed to monitor on an annual basis per the Public Staff's recommendation, no QFs (CSGs) have sought to avail themselves of the protocol, but if any CSGs do avail themselves of the protocol, DENC will continue to monitor the information requested by the Public Staff and will report on that information as needed in a future biennial avoided cost proceeding. *Id*. at 17-18.

The Public Staff does not object to the RDC avoidance protocol, and again recommends that the Commission 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." The Public Staff also repeats its recommendation that DENC "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." Public Staff Initial Comments at 50-51.

While it did not address the RDC avoidance protocol in the Sub 167 Avoided Cost Case, in this proceeding SACE objects to the protocol's annual output forecast requirement. SACE claims that no other type of resource is required to provide or capable of providing such a forecast. SACE also argues that the annual forecast will become outdated, and that the consistency of a solar QF's actual generation over the course of a year with such a projection is not directly relevant to variability or volatility of solar output or any resulting re-dispatch the solar generator may cause. SACE recommends that the Commission "require Dominion to adopt an RDC avoidance protocol that accurately reflects the solar QF's avoidance of the system costs, if any, imposed by solar generation," and requests that the Commission consider requiring review of DENC's compliance with SACE's RDC and RDC avoidance protocol recommendations by an independent technical review committee. SACE Initial Comments at 39-40.

In its Reply Comments, DENC explains that the purpose of the RDC is to account for the increased cost to dispatch onto DENC's system due to the addition of intermittent distributed solar generation QFs and, as a result, the purpose of the protocol is to permit solar generation QFs that want to avoid the RDC through an ESD to do so. As a result, solar generation QFs are the only facilities that must provide this forecast because they are the only facilities that impose the re-dispatch costs on the system. DENC Reply Comments at 20.

DENC notes that no QF is required to guarantee its hourly output over a year or more in advance or provide a perfect forecast. Instead, the RDC avoidance protocol is made available to intermittent QFs that choose to use an ESD to manage the output of the facility and is designed to allow for a proportional reduction of the RDC. *Id*.

DENC further explains that a year-ahead forecast allows a QF to account for the movement of the sun, the design of the QF facility, and some level of expected seasonable cloud cover, which DENC expects to be a smooth profile. DENC considered the deviation from this profile to be more reasonable than deviation from an observed mean, such as average hourly generation across a year, average hourly generation by month, average hourly generation by hour of day, or average hourly generation by hour of day by month. DENC believes the variability relative to the QF-provided profile (in the form of a year-ahead forecast) to be the most reasonable low-burden method to use to calculate a proxy for variability reduction achieved with an ESD. *Id*. at 21.

DENC acknowledges that it could conceivably use a day ahead forecast, but asserts that to do so would be significantly more burdensome than a single annual profile for both DENC and the QF as the QF would need to provide, and DENC would need to verify receipt of, an hourly forecast every day at least 24 hours in advance of the beginning of the day. Failure to provide a forecast would by necessity nullify the protocol for the year to protect customer interests and prevent gaming. DENC explains that an hour-ahead forecast would be even more burdensome and would not be appropriate for implementing the RDC, which is based on re-dispatch between the day ahead market and real time operations. DENC notes that no intervenor has presented evidence indicating that providing an annual hourly generation profile would be burdensome for a QF and expects that the information necessary to construct such a profile is typically available as part of the development of a solar facility. Regarding the “age” of the forecast, DENC considers the QF-provided forecast to be a proxy for a smooth profile, as the QF is in the best position to provide that profile. Considered as a smooth profile, DENC states that the age of the forecast is not relevant unless new information about the movement of the sun, the design of the facility, or seasonal cloud cover becomes available. *Id*. at 21-22.

DENC opposes SACE’s recommendation that the Commission require DENC to adopt a modified RDC avoidance protocol consistent with SACE’s recommendations and establish an independent technical review committee with stakeholder input to verify that the modified protocol meets SACE’s demands. DENC alleges that these requirements are unnecessary due to the appropriateness of the RDC avoidance protocol as presented in DENC’s Initial Statement and defended in its Reply Comments. *Id.* at 22.

Discussion and Conclusions

In the Sub 167 Order, the Commission concluded that DENC’s proposed RDC avoidance protocol was appropriate for use in that proceeding because it allowed the RDC to be reduced to the extent the QF reduces the variability of its output through the use of an ESD. The Commission further concluded that the proposed protocol is a reasonable proxy for estimating the reduction in redispatch costs incurred by CSGs. The

Commission relied on the Public Staff's determination that the protocol is reasonable in part because DENC's QF load reduction estimates incorporate output from the prior day (in addition to other variables), such that over time, as a CSG consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account. Sub 167 Order at 48.

The Commission continues to find DENC's protocol reasonable for the reasons articulated in the Sub 167 Order. In addition, the Commission agrees with DENC that it is not unreasonable to require QFs seeking to avail themselves of the RDC avoidance protocol to submit year-ahead forecast information, because it would be the QFs seeking the benefit of the resulting RDC reduction. The Commission also agrees with DENC that a year-ahead forecast is the most efficient and least burdensome requirement for both DENC and QFs seeking to avail themselves of the RDC avoidance protocol and therefore is appropriate for use in this proceeding. The Commission anticipates that most QFs will have this information, or similar information, available from the development of the solar project and that providing such information should not be overly burdensome. As the Public Staff did not raise any new issues with the RDC avoidance protocol and DENC has not made any changes from the protocol as approved in the Sub 167 Order, the Commission finds that DENC's RDC avoidance protocol continues to be reasonable for use in this proceeding.

The Commission further concludes that, if any QFs seek to avail themselves of the RDC avoidance protocol, the information that the Public Staff requests DENC to monitor and provide may be helpful in evaluating the results of the protocol in the future. The Commission finds that, should any CSGs paired with an ESD seek to avail themselves of the RDC avoidance protocol, DENC should 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 and an analysis of actual solar volatility of QFs in DENC's service territory in its future avoided cost filings. DENC should also 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.

Based on the evidence presented, the Commission concludes that DENC's avoidance protocol is appropriate for use in this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, the Public Staff's Initial Statement, SACE's Initial Comments, and the entire record herein.

Summary of the Comments

In its Initial Statement, Duke explains that the Commission directed it, as one of the Sub 158 Additional Issues, to evaluate real-time pricing tariff options for QFs selling under Schedule PP, specifically focusing on the new rate options FERC prescribes in Order No. 872. Duke explains that in Order No. 872, FERC amended its regulations to provide states greater flexibility to (1) utilize locational marginal prices (where available) or competitive prices to set rates for as available QF energy sales and, (2) mandate that variable avoided energy rates calculated at time of delivery could also be used to set the energy rates for QFs electing to sell energy pursuant to a LEO. 18 C.F.R. §§ 292.304(b)(6-7), (d)(1)(iii). With respect to the latter, Duke quotes Order No. 872 for the proposition that "flexibility to require that energy rates (but not capacity rates) in QF power sales contracts and other LEOs vary in accordance with changes in the purchasing electric utility's as available avoided costs at the time the energy is delivered." *Id*. at § 292.304(d)(2). Duke also states that FERC recognized that such as-available rates ensure that QF rates do not exceed the avoided cost rate cap that PURPA imposes, which balances the risk allocation between QFs and utility customers and allows rates to automatically adjust as avoided costs change. Finally, with respect to Order No. 872, Duke states that FERC's revised regulations permit state regulatory authorities to set as-available rates using either pricing established through a liquid market hub, or "Combined Cycle Prices" established by a state-approved formula incorporating "published natural gas price indices, a proxy heat rate, and variable operations and management costs." Duke Initial Statement at 38-39.

Consistent with FERC's policy goals and analysis in Order No. 872, Duke proposes to update its Schedule PP tariff to use the hourly marginal cost of producing energy (Marginal Cost Rates) to calculate avoided costs for QFs that elect to sell energy to Duke on an as-available basis. Duke explains that it will calculate the Marginal Cost Rates ex-post at the end of the month for each hour in a given month based on the joint dispatch outcomes for DEC and DEP during that month using the incremental cost of production of the next megawatt hour. Duke also explains that because the Marginal Cost Rates are calculated at the end of each calendar month, QF compensation will be based on actual marginal costs rather than market forecasts. Duke states that under this methodology, the "as-available" rates will accurately compensate QFs for the energy they provide based upon the utility's avoided costs calculated "at the time of delivery" in accordance with PURPA, while protecting DEC and DEP's customers from potential overpayment. Duke notes that it currently uses this methodology to calculate transmission and wholesale imbalance billing rates. *Id.* at 40.

Duke explains that it investigated developing a projection of avoided energy cost on a day-ahead basis but determined that QFs putting power to the utility and its customers under the as-available rate already have the option to sell to Duke or other markets, such as PJM, Southern Company, or DENC, in the forward day-ahead market based on the projected wholesale need and value of purchased power at that point in time. If the QF does not sell its output to Duke or other market participants, it can put its power to DEC or DEP under the "as-available" rate and receive the value of the avoided energy created for DEC and DEP's customers at the time of delivery using the ex-post pricing described in the rate. Duke also explains that QFs that commit to sell their full output to Duke, under a LEO, have other PURPA-guaranteed rate options for fixed price power sales of various terms, but for those QFs that elect to sell and deliver power "as-available" and maintain the option to sell off-system to another entity, the ex post methodology most accurately reflects the utility's actual avoided cost at the time of delivery and will best protect customers from over- or under-estimations of the actual costs avoided when the energy is delivered. *Id.* at 40-41.

Duke also explains that it is retaining the 2-year Variable Rates contract option that exists under the Schedule PP approved in the 2020 Sub 167 Order, but this rate option will now require a QF to contractually obligate itself to sell and deliver power for at least a two-year term to reflect that DEC and DEP are forecasting avoided costs over this period. *Id.* at 41.

Finally, Duke notes that, after discussion with the Public Staff and other stakeholders, for this proceeding, it is not proposing to offer a long-term fixed capacity rate and variable energy rate option based upon DEC's and DEP's avoided energy cost calculated at the time of delivery, as now allowed under 18 C.F.R. 292.304(d)(2). Duke states that in future biennial proceedings, it will continue to evaluate this concept along with the other new options for establishing avoided cost rates under FERC's implementing regulations, as updated in Order No. 872. *Id.*

In its Initial Statement, the Public Staff states that it has worked with Duke to develop the as-available rates that Duke proposed in its Initial Statement and notes that because DEP and DEC are not members of a RTO, developing a real-time pricing tariff is more complex. The Public Staff explains that it supports Duke's proposal because it will reduce overpayment risk to QFs that do not contractually obligate themselves to sell and deliver power to Duke for a fixed term. The Public Staff also notes that as of December 2021, only three small hydro QFs are selling power to Duke under "as-available" rates, so the anticipated impact of this proposal will be minimal. Public Staff Initial Statement at 13-14.

In its Initial Comments, SACE argues that Duke's proposal to calculate rates ex-post at the end of the month is not appropriate. SACE explains that in Order No. 872, FERC rationalized allowing states to shift to avoided cost rates with variable energy components while maintaining a fixed capacity component because it determined this was a construct found elsewhere in the electric industry. SACE argues, however, that calculation a month after the fact is not standard in the industry. According to SACE, ex-post calculation creates additional uncertainty and imposes a cost and inflates QF overall project costs which effectively imposes a decrement on the rates a QF receives. SACE notes that this will make QF financing more difficult and weaken the PURPA market. SACE argues that a price set ex-ante and adjustment more frequently is a better alternative. SACE Initial Comments at 31-32.

Duke's Reply Comments note the Public Staff's support for its as-available rates and respond to SACE's comments. Duke explains that SACE's comments focus on the changes Order No. 872 implemented to the LEO option under 18 CFR § 292.304(d)(1)(ii) that recognized the benefits of more accurate avoided energy rates over the term of the QF contract, but that DEC's and DEP's Marginal Cost Rates are intended to meet the "as available" requirements under 18 CFR § 292.304(d)(1)(i) for QFs that elect not to contract to sell their capacity and energy over a specified term. Duke also states that SACE's claim that the ex-post calculation methodology will make QF financing more difficult misses the point that DEC's and DEP's Marginal Cost Rates are "as available" rates where the QF is not contracting to sell its capacity and energy to DEC or DEP for any specified future term. Duke notes that for a QF that desires a short-term rate but seeks a fixed price and commits to deliver capacity and energy over a future term, DEC and DEP offer other PURPA-guaranteed rate options for fixed price power sales of various terms, including the short-term 2-year Variable Rates contract option the Commission approved in the 2020 Sub 167 Order. Duke Reply Comments at 33-34.

Duke also states that SACE is incorrect that DEC's and DEP's proposed method to calculate the Marginal Cost Rates is not utilized in the industry today. Duke notes that the Public Staff acknowledges that DEC and DEP use this same methodology to calculate transmission and wholesale imbalance billing rates. In addition, Duke explains that Duke Florida uses a similar ex-post methodology to calculate as-available avoided energy cost rates to meet its PURPA rate obligations in that jurisdiction. Duke reiterates that the Marginal Cost Rate should be adopted and offered to QFs that elect only to sell as-available energy versus contracting to sell power to DEC or DEP for a specified future term. *Id*. at 34-35.

Discussion and Conclusions

FERC issued Order No. 872, updating FERC's regulations implementing PURPA, on July 16, 2020, and this Commission acknowledged in its 2020 Sub 167 Order that Order No. 872 may "driv[e] additional changes to PURPA implementation and the determination of avoided cost rates in North Carolina." Order No. 872 ultimately gives states more flexibility to set rates for as-available energy sales and requires that variable avoided energy rates calculated at the time of delivery be used to set energy rates for QFs electing to sell energy pursuant to a LEO. 18 C.F.R. §§ 292.304(b)(6-7), (d)(1)(iii). Any rates set, however, still must not exceed the avoided cost rate cap that PURPA imposes.

The Commission acknowledges Duke's attention to Order No. 872 and its impact on this proceeding as shown by multiple stakeholder meetings Duke conducted and its proposal to update its Schedule PP tariff to use the Marginal Cost Rates to calculate avoided costs for QFs that elect to sell energy to DEC and DEP on an as-available basis. The Commission also finds Duke's proposal, as supported by the Public Staff, to calculate the Marginal Cost Rates ex-post at the end of the month for each hour based on the joint dispatch outcomes for DEC and DEP and the incremental cost of production of the next megawatt hour to be reasonable. This methodology ensures that utilities accurately compensate QFs based on the time they provide the energy while also protecting DEC's and DEP's customers from overpayment.

The Commission is not persuaded by SACE's argument that Duke's ex-post calculation will make QF financing more difficult because Duke's as-available rates do not require a QF to contract with DEC or DEP to sell its capacity and energy for any specified future term. Instead, if QFs desire a short-term rate, but seek a fixed price while committing to sell capacity and energy over a future term, they can select other PURPA options for fixed price power sales of capacity and energy over a specified term as provided for in 18 C.F.R. 292.304(d)(1)(ii).

The Commission further finds reasonable Duke's proposal to retain its 2-year Variable Rates contract option under Schedule PP, as approved in the 2020 Sub 167 Order, and to add a requirement that a QF must contractually obligate itself to sell and deliver power for at least a two-year term.

Based upon the foregoing and the entire record, the Commission accepts Duke's use of Marginal Cost Rates to calculate avoided cost rates on an as-available basis and accepts its added fixed term requirement to its two-year Variable Rates contract option under Schedule PP as reasonable for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-27

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments, the Public Staff's Initial Statement, the Initial Comments of SACE, and the entire record herein.

Summary of the Comments

In its Initial Statement, Duke explains that Schedule PP pays QFs on a volumetric rate basis where both energy and capacity rates are paid on a $/kWh basis versus a separate fixed payment for capacity. DEC and DEP note that the Schedule PP rates are designed to credit QFs for avoided energy supplied during pre-designated on-peak and off-peak hours. Duke Initial Statement at 41-42.

Duke's Initial Statement also explains that in the 2018 Sub 158 proceeding, DEC and DEP initially proposed an updated Schedule PP rate design that eliminated the pre-existing Option A and Option B rate structures and proposed more granular rate designs to better recognize the value of QF energy and capacity. In the 2018 Sub 158 proceeding Duke and the Public Staff filed a Partial Settlement on April 18, 2019, to achieve these goals, recommending an energy rate and capacity rate design method for use in the Sub 158 Proceeding and in future proceedings (Sub 158 Rate Design Stipulation). Agreement and Stipulation of Partial Settlement, Docket No. E-100, Sub 158 (Apr. 18, 2019). Duke's Initial Statement explains that the 2018 Sub 158 Order approved the Sub 158 Rate Design Stipulation and found the rate designs included therein to be appropriate for use in calculating DEC's and DEP's avoided energy and capacity rates. Duke states that, for purposes of this proceeding, it is continuing to use the Commission-approved energy rate designs as outlined in the Sub 158 Rate Design Stipulation and as the Commission approved in the 2018 Sub 158 Order and 2020 Sub 167 Order. *Id*.

Duke also notes that, pursuant to the Commission's directive in the 2020 Sub 167 Order, Duke worked with the Public Staff to review DEC's and DEP's approach to inclusion of CT start costs used in production cost modeling. In Exhibit 8 to the Duke Initial Statement, Duke explains that DEC and DEP modified their start cost modeling to resolve unintended impacts on the avoided energy pricing periods. Specifically, Duke explains that start-up and shut-down costs are distributed over the anticipated operation and added to the per MWh and per Hour cost components. Total O&M costs, including start costs, are captured in this approach while providing intuitive and appropriate avoided energy price signals. Duke explains that this method is consistent with the modeling approach utilized in the approved 2018 Sub 158 and 2020 Sub 167 avoided energy rates, and the Public Staff has indicated that it supports Duke's approach to this calculation. Duke Initial Statement at 42-43, Exhibit 8; Sub 167 Order at 40.

Duke explains that, under the Sub 158 Rate Design Stipulation, QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours representing the hours most likely to have capacity value. Duke states that this is consistent with the approach it has historically utilized with respect to QF rate design under prior versions of Schedule PP. Duke explains that it developed DEC's and DEP's seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the 2020 resource adequacy study by Astrapé Consulting as inputs to the capacity rate design in this proceeding. Duke Initial Statement at 44. Duke notes that all of the inputs were updated in the new study, the solar projections were increased compared to the previous study, and Astrapé incorporated an enhancement for modeling load during extreme cold weather which shifted some of the winter loss of load risk from PM hours to AM hours. *Id.*

Duke explains that the Schedule PP capacity rate design in this proceeding reflects updated pricing periods to most accurately reflect the marginal capacity value to customers during each period. Duke specifies that, for DEC, the updated pricing periods include capacity payments during the PM hours in the summer months of July and August and during the AM hours in the winter months of December, January, February, and March. For DEP, the updated pricing periods include AM hours during the winter months of December, January, February, and March and do not include a summer pricing period. Duke notes that no capacity payments apply during the remaining months for either DEC or DEP and that the highest prices are paid in the early morning winter hours in order to recognize the greater loss of load risk and greater value of capacity during those hours. *Id.* at 44-45.

Duke also explains that the seasonal allocation of capacity value remains heavily weighted to winter based on the impact of summer versus winter loss of load risk. Specifically, Duke states that DEP's loss of load risk is 100% winter – unchanged from the approved allocation in the 2018 Sub 158 Order and 2020 Sub 167 Order – and DEC's loss of load risk is 96% winter – an increase from the approved 90% allocation in the 2018 Sub 158 Order and 2020 Sub 167 Order – based on the 2020 Resource Adequacy Study. *Id.* at 45.

Finally, Duke notes that it engaged with the Public Staff prior to filing its Initial Statement in this proceeding and that it plans to continue discussing the accuracy and appropriateness of the rate design with the Public Staff in advance of the next biennial avoided cost proceeding in 2023. *Id.*

In its Initial Statement, the Public Staff states that it reviewed Duke's seasonal allocations and other assumptions incorporated into DEC's and DEP's avoided costs, finds the avoided capacity rates reflected in Schedule PP to be reasonable, and recommends that the Commission approve them. The Public Staff also states that it finds Duke's revised approach for modeling start costs to be reasonable for this proceeding because Duke has produced rates that generally align with the purpose of the Sub 158 Rate Design Stipulation approved in the Sub 158 Proceeding. Public Staff Initial Statement at 37-39, 46-47.

No other party comments on Duke's rate design, start costs, or use of seasonal allocations in this proceeding, or otherwise raises objections with respect to these issues.

Discussions and Conclusions

In the 2016 Sub 148 Order, the Commission observed that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities." 2016 Sub 148 Order at 56. The Commission therefore required the Utilities to consider refinements to the avoided capacity rates and to address these refinements in the Sub 158 proceeding. *Id*. The Commission directed the Utilities to consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." *Id.*

In the 2018 Sub 158 Scheduling Order, the Commission similarly directed the Utilities to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules." 2018 Sub 158 Scheduling Order at 1-2. In response to those directives, Duke and the Public Staff worked together throughout the Sub 158 Proceeding to reach the Sub 158 Rate Design Stipulation, which the Commission approved. 2018 Sub 158 Order at 25. As explained in the 2020 Sub 167 Order, the Commission specifically approved the Sub 158 Rate Design Stipulation because: (1) the Commission found merit in the general approach utilized by the Public Staff to develop granular pricing methods for avoided energy that more accurately reflect Duke's highest production cost hours and loads to increase the likelihood that the interests of ratepayers and developers of QF generators align; (2) the modifications made through discussions between the Public Staff and Duke to further refine the rate design approach, as memorialized in the Sub 158 Rate Design Stipulation, struck an appropriate balance between accurate avoided cost pricing, administrative efficiency, and the general acknowledgment that these factors will continue to change over time; and (3) the stipulated rate design was the result of a methodological approach to evaluate system costs and impacts as described in the Rate Design Stipulation and properly aligned price signals provided in the rate design with Duke's avoided energy costs. Sub 167 Order at 39-40.

In this proceeding, based upon the foregoing and the entire record herein, the Commission finds that Duke has adhered to the Sub 158 Rate Design Stipulation in designing rates and appropriately utilized the loss of load risk identified in Duke's 2020 Solar Resource Adequacy Study for refining the capacity rate design in this proceeding.

The Commission also finds that Duke and the Public Staff have reasonably addressed the Commission's directive in the Sub 167 Order to address the issues associated with modeling start costs in the production cost model by spreading these costs over all hours that the individual unit operates.

For purposes of this proceeding, the Commission approves DEC's and DEP's rate design and resulting avoided energy and capacity rates, as updated using the 2020 Resource Adequacy Study and as presented in Duke's Initial Statement. The Commission also approves DEC's seasonal allocation of capacity value of 100% to winter and DEP's seasonal allocation of capacity value of 96% to winter. The Public Staff supports, and no other parties take issue with, Duke's Initial Statement on these issues.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-29

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

Summary of the Comments

In its Initial Statement, DENC describes the method it used for purposes of calculating energy rates. That rate design, which the Commission approved in the Sub 167 Order, comprises nine pricing periods: summer off-peak; summer on-peak; summer premium peak; winter off-peak; winter on-peak am; winter on-peak pm; winter premium peak; and shoulder on- and off-peak periods. DENC has maintained these pricing periods in calculating energy rates for purposes of this proceeding. DENC has continued to allocate its CT costs using the seasonal allocation weighting approved in the Sub 167 Order of 45% summer, 40% winter, and 15% shoulder. DENC Initial Statement at 4-5, 22.

In its Initial Statement, the Public Staff states that DENC's method for designing energy and capacity rates for Schedule 19FP is largely consistent with methods employed in the 2020 Avoided Cost Case and does not raise any concerns with maintaining this rate design. Public Staff Initial Statement at 47-48. The Public Staff also acknowledges that DENC's weighting capacity value between seasons remains consistent with the Sub 158 Order and does not raise any concerns with maintaining this weighting. *Id*. at 39.

No other party proposes changes to DENC's rate design or seasonal allocation weightings or otherwise raises objections with respect to these issues.

Discussion and Conclusions

In the Sub 158 Order, the Commission required DENC to use the rate design agreed upon by DENC and the Public Staff in that proceeding. The Commission found that the revised rate design was responsive to the directives in the Sub 148 Order and the Sub 158 Scheduling Order by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further found that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40%

for winter, and 15% for shoulder seasons were appropriate for use in weighting capacity value between seasons, as these weightings continued to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder capacity. Sub 158 Order at 98. The Commission concluded it to be appropriate for DENC to continue using this rate design and these seasonal allocation weightings in the Sub 167 Order. Sub 167 Order at 42.

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed rate design, unchanged from the rate design approved in the Sub 158 and Sub 167 Orders, is appropriate to continue using to calculate rates for DENC's nine pricing periods for purposes of this proceeding. No party has raised any concern with DENC's rate design, which continues to provide QFs with granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further concludes that DENC's continued use of the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons, also unchanged from the seasonal allocations approved in the Sub 158 and Sub 167 Orders and without objection in this proceeding, are appropriate for use in weighting capacity value between seasons for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-31

The evidence supporting these findings of fact is found in Duke's Initial Statement and Reply Comments.

<u>Summary of the Comments</u>

In their Initial Statement, DEC and DEP explain the minor modifications made to their Schedule PP Tariff to reflect the updated avoided cost rates and the revised as-available rate structure. These modifications include administrative revisions for improved clarity and consistency, ensuring that references to rates accurately and clearly distinguish between Long-Term Rates, Variable Rates, and new Marginal Cost Rates. Regarding Marginal Cost Rates, Duke explains that in the 2002 avoided cost proceeding, the Commission directed that the two-year variable rate act as the "as available" rate for purposes of the standard offer. Because Duke has proposed an updated methodology for determining the "as available" rates that is consistent with FERC's recent Order No. 872, as well as maintained the two-year variable rate offer, Duke is amending its tariffs to reflect the distinct rate offers. Duke Initial Statement at 46.

Further, Duke explains that it updated and simplified the Capacity Credit schedule to reflect that hydroelectric generation QFs receive the same capacity credits as other QFs. The Capacity Credit schedule reflects that there are two applicable categories for hydro QFs depending upon whether they are a legacy hydro QF or a hydro QF that does not qualify for the statutory exemption and that is eligible for capacity credits beginning in the first year of a utility's capacity need. *Id*.

Duke also explains that it added a new Marginal Cost Rates section to Schedule PP which discusses how such rates are developed and calculated at the end of each calendar month, for each hour of the month, and how eligible QFs may receive the rates after executing a non-disclosure agreement. *Id*. at 47.

Finally, Duke proposes to reduce the monthly Administrative Charge (DEC) or Monthly Seller Charge (DEP) ("seller charges") to $3.00 per month for QFs with capacity of 15 kW (AC) or less. Duke notes in its Initial Statement that it has not proposed an associated increase in seller charges for other QFs to make up for the revenue loss. *Id.*

In the Terms and Conditions for the Purchase of Electric Power, Duke states that it has revised Section 6 to use the Marginal Cost Rates as the benchmark for calculating early termination payments for the period on and after November 1, 2021, which replaces the use of Variable Rates for this purpose. Duke has also modified Section 9 to reflect the new service regulation standard that a "Month" for billing purposes is 26-34 days. *Id.*

Duke's Initial Statement also explains that Duke has made limited revisions to its standard offer PPA forms presented in DEC's and DEP's respective Exhibit 3. The revised standard PPA forms now refer to the new Marginal Cost Rates and clarify that any automatic extension of the Agreement would use the as-available rates, which, in DEC's and DEP's proposal is now the Marginal Cost Rates. For the sake of clarity, because it does not apply to Eligible QFs of 1,000 kW (1MW) and under, Duke has also removed a reporting requirement provision (Section 6 of the PPA form). Duke clarifies in its Initial Statement that it will continue to use the Section 6 requirement in non-standard offer PPAs for larger QFs. Additionally, Duke makes limited clarifying revisions to the Capacity Hour Windows concept in the Exhibit A Energy Storage Protocol. *Id*. at 48.

No other party to this proceeding commented on Duke's proposed revisions to its Standard Offer documents, including the proposed revisions to DEC's and DEP's respective Schedule PPs, Standard Offer Terms and Conditions, and Standard Offer PPA.

Discussion and Conclusions

Based on the foregoing and the entire record herein and given that no party expressed any objection to the revisions Duke proposes, the Commission finds that the revisions to DEC's and DEP's respective Schedule PPs, Standard Offer Terms and Conditions, and Standard Offer PPA are reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting this finding of fact is found in Duke's Initial Statement and Reply Comments, the Public Staff's Initial Statement, the Initial Comments of CCEBA/NCSEA, the Reply Comments of SACE, and the entire record herein.

Summary of the Comments

Duke presents DEC's and DEP's updated Notice of Commitment Forms in DEC/DEP Exhibit 6 (for QFs up to 1 MW eligible for Schedule PP) and DEC/DEP Exhibit 7 (for large QFs). In its Initial Statement, Duke explains that it is proposing to update DEC's and DEP's Notice of Commitment Forms to accomplish three primary objectives: (1) incorporating the new commercial viability and financial commitment requirements established in FERC Order No. 872; (2) aligning the Notice of Commitment Form with the now-approved queue reform process under the North Carolina Interconnection procedures; and (3) updating the non-standard offer Notice of Commitment Form to establish a more standardized and efficient process for QFs to proceed from Notice of Commitment Form to PPA. Duke Initial Statement at 49.

With respect to FERC Order No. 872, Duke explains that FERC adopted 18 C.F.R. 292.304(d)(3), which now requires new QFs to "demonstrate commercial viability and financial commitment to construct its facility . . . as a prerequisite to a qualifying facility obtaining a legally enforceable obligation." FERC Order No. 872, at ¶¶ 684-96. Duke explains that FERC identified several examples of factors that could reasonably demonstrate a QF's commercial viability and financial commitment, including that the QF: (1) is taking meaningful steps to obtain site control adequate to commence construction; (2) has filed an interconnection application with the appropriate entity; (3) has submitted applications, including filing fees, to obtain all necessary local permitting and zoning approvals; and (4) has met objective and reasonable milestones in development that can demonstrate financial commitment. *Id*. at 49-50 (citing FERC Order No. 872, at ¶¶ 685-690).

In line with this guidance, Duke explains that Attachment C to the Notice of Commitment Form requires the QF to show that it: (1) has obtained a CPCN; (2) for new QFs requesting to interconnect to the utility's system, the QF has met all requirements to enter the Definitive Interconnection Study Process under NCIP Section 4.4.1. and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5; (3) has site control for the entire proposed term of delivery under a future PPA; and (4) provides reasonable evidence and documentation of the QF's commitment to develop the project by including a status update on permitting, procurement of any long lead-time materials, execution of third-party engineering, procurement and construction contracts to construct the facility, and executing of any third-party transmission agreements, if applicable. Duke asserts in its Initial Statement that each of these requirements are reasonable, objective, and within the control of the QF Developer. *Id.* at 51.

In addition, Duke states that it has modified DEC's and DEP's Notice of Commitment Forms to align with the new Definitive Interconnection Study Process, which restructures the traditional North Carolina Interconnection Procedures (NCIP) Section 4.3 serial System Impact Study into a multi-step Cluster Study process under NCIP Section 4.4.7. Duke explains that a key objective of queue reform is to reduce the number of speculative projects entering the interconnection process by increasing study deposits, commercial readiness requirements and financial commitments for non-ready projects as they progress through the interconnection study process. Duke explains that a new QF proposing to interconnect and sell and deliver power to DEC or DEP, must demonstrate that it has: (1) submitted an interconnection request to become an Interconnection Customer of the Company; (2) provided initial security requirements under NCIP Section 4.4.1; and (3) executed a DISIS Agreement pursuant to NCIP Section 4.4.5. DEC and DEP assert that their updated Notice of Commitment Forms align with the DISIS process as a binding Notice of Commitment and that QF's can be used to demonstrate project readiness at both the M1 and M2 milestones. *Id*. at 52-53.

Finally, Duke also proposes to update the Notice of Commitment Form to provide a more standardized and streamlined process for QFs to progress from a Notice of Commitment Form to a mutually binding PPA. Specifically, Duke has updated Section 3 and Attachment B of the Large QF (those not eligible for Standard Tariff) Notice Commitment Form to now establish a standardized process for the QF to provide all information that DEC and DEP require to develop a negotiated QF PPA and commits that DEC and DEP will deliver an executable PPA back to the QF within 30 days. The QF would then have a period of 90 days to work with the utility to finalize and execute the PPA, with this period being automatically extended to no earlier than 30 days after receiving a Facilities Study Agreement from the Company.

In its Initial Statement, the Public Staff states that it generally supports Duke's revisions to DEC's and DEP's Notice of Commitment Forms. Moreover, the Public Staff agrees with Duke that the revisions incorporate the new commercial viability and financial commitment requirements established in Order No. 872, align the LEO process with the new DISIS process, and establish a more standardized and efficient process for QFs to proceed from the Notice of Commitment to PPA. Public Staff Initial Statement at 56. The Public Staff states that Duke needs assurances that projects entering into the DISIS study process are commercially viable and progressing toward construction and the sale of the project's output to the utility in order to rely on those projects in Duke's planning process. The Notice of Commitment Form, as the Public Staff explains, is designed to provide a more efficient path for QFs to commit themselves to deliver capacity by executing a PPA and imposing a hard deadline for the QFs to do so after receiving a Facilities Study Agreement. Finally, the Public Staff notes that obtaining a LEO allows QFs to show readiness in the DISIS process and to submit a smaller financial commitment to enter and continue through the early stages of the DISIS process. Public Staff Initial Statement at 56.

In their Joint Initial Comments, CCEBA/NCSEA state that they are "generally comfortable" with Duke's proposed changes to its Notice of Commitment Form for QFs larger than 1 MW (AC). However, CCEBA/NCSEA express concern that proposed Section 4 of the Large QF Notice of Commitment Form may make it difficult for QFs to obtain financing. CCEBA/NCSEA explain that Section 4 requires the QF to represent that it will begin delivering output to Duke no later than 365 days after the Notice of Commitment Form Submittal Date. CCEBA/NCSEA point out that, given that Duke's expected timeframe to complete interconnection studies and construct interconnection facilities is approximately four years, Section 4 would prevent a QF from forming a LEO and securing pricing until approximately three years into the interconnection study and construction process. CCEBA/NCSEA Initial Comments at 22. According to

CCEBA/NCSEA, no QF has been financed or built with such a lack of price certainty and none would be in the future. CCEBA/NCSEA further note that Duke's proposed work-around of a day-for-day extension of the 365-day deadline for any days by which Duke's completion of the interconnection facilities and network upgrades exceeds the QF's requested interconnection date is insufficient to remedy the issue. *Id*. at 23. To remedy the issue, CCEBA/NCSEA propose that Duke revise Section 4 to instead require such new QFs seeking interconnection to the DEC or DEP systems to begin delivering energy output within 90 days of DEC's or DEP's completion of all required interconnection facilities and network upgrades. *Id*. at 24.

As Exhibit 1 to its Reply Comments, Duke filed an updated Large QF Notice of Commitment Form. According to Duke, the revisions address CCEBA/NCSEA's concerns. First, Duke explains that the revised Notice of Commitment Form now distinguishes between existing QFs (with existing interconnection agreements) that are already interconnected to DEC's or DEP's system and new QFs seeking interconnection that have not yet achieved commercial operation. Pursuant to the revisions, Duke explains, existing QFs must commence delivery of its output within 365 days after submitting a Notice of Commitment Form; new QFs, however, must only commence delivery no later than 90 days after its in-service date. Duke Reply Comments at 45; Exhibit 1 at 11.

Also, in response to CCEBA/NCSEA's stated concerns, Duke's Exhibit 1 to its Reply Comments modifies Section 4 to allow further extension of the in-service date-where the Seller is making a good faith effort to advance the project but is delayed due to circumstances beyond its control and which do not result from its fault or negligence. Duke Reply Comments at 44-45. In their Reply Comments, CCEBA/NCSEA note that they reached agreement with Duke on revisions to the Notice of Commitment Forms. CCEBA/NCSEA Reply Comments at 1-2. The Public Staff's Reply Comments acknowledge that Duke shared a draft of the revised Notice of Commitment Form before filing it with the Commission. The Public Staff states that it supports the revisions and commends the parties in coming to an agreement. Public Staff Reply Comments, at 7-8.

SACE's Reply Comments state that SACE agrees with CCEBA/NCSEA's critique and recommends revisions to Section 4 of Duke's proposed Notice of Commitment Forms. SACE Reply Comments at 10.

<u>Discussion and Conclusions</u>

In Order No. 872, FERC adopted 18 C.F.R. 292.304(d)(3), which now requires new QFs to "demonstrate commercial viability and financial commitment to construct its facility . . . as a prerequisite to a qualifying facility obtaining a legally enforceable obligation." FERC Order No. 872, at ¶¶ 684-96.

The Commission notes that Duke, CCEBA/NCSEA and the Public Staff worked together to address identified issues and develop an amended Large QF Notice of Commitment Form. In addition to the fact that all parties appear to agree regarding the terms of the Notice of Commitment Forms, the Commission finds that Duke's proposed revisions appropriately incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872. The revised Notice of Commitment Forms further balance Duke's need for assurance that projects entering into the DISIS study process are commercially viable and progressing toward construction and sale of the project's output with QFs' need for reasonable opportunities to obtain financing. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to approve Duke's Notice of Commitment Forms as presented in DEC/DEP Exhibit 6 (for QFs up to 1 MW eligible for Schedule PP) and DEC/DEP Reply Comments Exhibit 1 (for large QFs not eligible for the standard offer).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence supporting these findings of fact is found in DENC's Initial Statement and Exhibits and Reply Comments and the entire record herein.

Summary of the Comments

In its Initial Statement, DENC refers to the Commission's Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations issued on August 17, 2021, in Docket Nos. E-100, Sub 158 and E-100 Sub 101 (Retrofit Storage Order), in which the Commission made several rulings on the Retrofit Storage Stakeholder Group report DENC filed jointly with Duke in that docket in September 2020. As relevant to DENC, in the Retrofit Storage Order the Commission concluded that: (1) a new CPCN is not required for the addition of storage to an existing generating facility, but the facility must file with the Commission written notice of the amendment to either the applicable CPCN or the report of proposed construction consistent with Commission Rules R8-64 and R8-65; (2) the addition of energy storage to an existing generating facility requires an amendment to the existing PPA and does not require execution of a new PPA; and (3) the term for retrofit energy storage shall be the same as the term that remains on the PPA for the facility. DENC Initial Statement at 25.

DENC notes that in the Retrofit Storage Order, the Commission approved the parties' agreement that DC-coupled energy storage systems should be allowed once revenue grade meters are available, and directed the Utilities to provide an update on the status of the availability of DC meters in initial filings in the 2021 avoided cost proceeding. Relevant to this directive, DENC explains that ANSI C12.32 – "American National Standard for Electricity Meters for the Measurement of DC Energy" – was published on March 4, 2021, and outlines the acceptable performance criteria for commercial, revenue-grade, DC meters. DENC states that with this standard published, the next step is for meter manufacturers to have their meters tested to the new standard's requirements. At the time of DENC's Initial Statement, based on DENC's communications with several meter manufacturers, none of those manufacturers have a meter certified under the new standard. DENC states that once an ANSI-compliant DC meter is available, it will need to determine an appropriate method to test its accuracy, both in a lab and in the field. *Id*. at 25-26.

Also, in the Retrofit Storage Order the Commission noted that the parties did not address the procedure for how and the point in time at which a facility secures eligibility for a specific avoided cost rate or methodology when adding energy storage and directed the parties to address this issue for resolution by the Commission. DENC posits that a QF that desires to incorporate energy storage to an existing facility, the output of which the QF has committed to sell to DENC, would submit to DENC a new LEO Form reflecting the retrofitted facility, and the avoided cost rate and methodology that are current at the time the QF submits the LEO Form would apply to the retrofit storage component. DENC proposes new LEO Forms specific to retrofit storage additions to be available to QFs seeking to establish LEOs for such projects. DENC proposes that, consistent with the Commission's conclusion in the Retrofit Storage Order that the addition of energy storage to an existing generating facility requires an amendment to the existing PPA and does not require execution of a new PPA, DENC and the QF would execute an amendment to the existing PPA to account for the retrofit storage. DENC clarifies that, consistent with the Commission's ruling that the term for retrofit energy storage shall be the same as the term remaining on the PPA for the facility, the QF would receive the annual levelized rate as approved in this proceeding for each of the remaining years of the original PPA, even if more than 10 years remains in the term. *Id*. at 26-28.

DENC indicates that, regarding the interconnection of retrofit storage additions, the existing NCIP provides a sufficient framework and process for DENC to study requests to add battery storage at existing distribution voltage sites in DENC's service area. DENC explains that to pursue an energy storage retrofit to a solar farm in operation in a serial study process, the Interconnection Customer will submit an Interconnection Request with a study deposit to study and identify any grid or protection modifications necessary to accommodate the proposed energy storage interconnection. To pursue an energy storage retrofit for an Interconnection Request that is in active study or in construction, the Interconnection Customer would submit a Modification Inquiry so that DENC can determine if the energy storage addition is a Material Modification. If it is a Material Modification, DENC would require the Interconnection Customer to submit a new Interconnection Request and study deposit to pursue the energy storage retrofit under a new queue number. If it is not a Material Modification, the study and any construction parameters would be incorporated under the existing queue number with the Interconnection Customer submitting an Interconnection Request documenting the additional information needed to study the energy storage. *Id*. at 28.

Finally, DENC explains that in the Retrofit Storage Order the Commission encouraged the parties to continue to investigate issues related to retrofit storage additions, "including term and rate design, to incent the addition of storage to uncontrolled generating facilities in the interest of providing value to the utilities' systems." DENC states that the rate design the Commission approved in the 2018 and 2020 Avoided Cost Cases provides a high degree of granularity and incentives for QFs to determine whether to add storage capability to their facilities, and that there is no need to revise that rate design at this time. DENC notes that if a QF desires even greater granularity and price signals than what is offered by the current Schedule 19-FP rate design, DENC's Schedule

19-LMP offers the most precise price signals possible and continues to be available to QFs to select. *Id*. at 28-29.

No parties raised any concerns with DENC's proposed Retrofit Storage LEO Forms or process for addressing QFs seeking to add retrofit storage to their facilities. In its Reply Comments, DENC notes the Public Staff's confirmation that it does not object to DENC's Retrofit Storage LEO Forms. *Id*. at 23, n.49.

Discussion and Conclusions

As DENC describes in its Initial Statement, in the Retrofit Storage Order, the Commission made several rulings regarding the addition of storage to an existing generating facility, and directed the Utilities to provide an update on the status of the availability of DC meters in its initial filings in the 2021 avoided cost proceeding as well as to address the procedure for how and the point in time in which a facility secures eligibility for a specific avoided cost rate or methodology when adding storage. Retrofit Storage Order at 7-8, 10-11.

The Commission finds that DENC's proposed procedure to be applied if an Interconnection Customer adds storage to its existing facility is reasonable and is approved. Specifically, the Commission finds that DENC's proposals to execute an amendment to the existing PPA, provide avoided cost rates as approved in this proceeding for the duration of the existing PPA term, and follow the already-provided framework under the NCIP and the "material modification" process therein are reasonable as they are consistent with the Commission's findings in the Retrofit Storage Order, not contested by any party, and appropriate given DENC's specific circumstances as discussed in its Initial Statement.

The Commission finds that DENC's proposed Retrofit Storage LEO Forms, as modified by the letter and exhibits filed by DENC on June 29, 2022, are reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

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

Summary of the Comments

In its Initial Statement, DENC discusses FERC Order No. 872, issued on July 16, 2020, which updated FERC's regulations implementing PURPA. DENC notes that Order No. 872 imposed new rules with respect to the (1) one-mile rule, given the development of large numbers of affiliated projects, and (2) viability of a project as FERC required that QFs now must "demonstrate that a proposed project is commercially viable and that the QF has a financial commitment to construct the proposed project, pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO." Order No. 872 at ¶ 684.

DENC proposes to revise its LEO Forms to include confirmation that the QF is not less than one mile, or between 1 and 10 miles, of an affiliated facility using the same energy resource. DENC explains that if the QF is located between 1 and 10 miles of an affiliated facility using the same energy resource, the revised LEO Forms allow the QF to provide more detailed confirmations to rebut the presumption that it is located at the same site as the affiliated project. DENC Initial Statement at 29-31.

DENC also proposes to modify its LEO Forms to include a statement by the QF to demonstrate commercial viability and financial commitment, stating that the QF has taken meaningful steps to obtain site control adequate to commence construction of the project at the proposed location and submitted all required applications, including filing fees, to obtain all necessary local permitting and zoning approvals. DENC believes that these modifications, in combination with the existing requirement that the QF must have submitted an Interconnection Request and reached certain milestones in the interconnection process, will ensure that the QF sufficiently demonstrates its commercial viability and financial commitment to justify obtaining a LEO consistent with Order No. 872. *Id*. at 31-32.

In its Initial Statement, the Public Staff generally supports DENC's revisions to its LEO Forms. The Public Staff finds that those modifications are consistent with Order No. 872 and recommends that the Commission approve the revised LEO Forms. Public Staff Initial Comments at 55-57.

In its Reply Comments, SACE objects to DENC's originally proposed revisions to its LEO Form, which required a QF that is located between 1 and 10 miles from an affiliated facility to provide additional information to rebut the presumption that it is located at the same site as the affiliated project. SACE states that the presumption under the one-mile rule is that facilities located between 1 and 10 miles from one another are at separate sites and there is no need to provide DENC with additional information concerning their separateness. SACE also expresses concern that requiring the additional information could result in confusion between the LEO Form and the QF's FERC Form 556. SACE Reply Comments at 7-8.

On June 29, 2022, DENC filed a letter addressing SACE's comments and proposing to revise the changes to DENC's LEO Forms to require only factual statements regarding a QF's geographic location with respect to any affiliates using the same energy resource, but no additional information. DENC represented that it had discussed its revised changes with SACE and that SACE agreed that the changes address its main concern with DENC's updated LEO Forms.

<u>Discussion and Conclusions</u>

Based on the evidence presented herein, the Commission finds and concludes that DENC's revisions to its LEO Forms to include an affirmative statement of commercial viability and financial commitment are reasonable and consistent with Order No. 872 and approves the revisions. The Commission also finds that the revisions to DENC's LEO Forms to incorporate FERC's updates to the one-mile rule, as modified by DENC's June

29, 2022 letter and exhibits, are reasonable and consistent with Order No. 872 and approves those revisions as well.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-36

The evidence supporting these findings of fact is found in Duke's Initial Statement, the Initial Statement of the Public Staff, Duke's Reply Comments, and the entire record herein.

Summary of the Comments

Duke's Initial Statement presents DEC's and DEP's proposed new ESS Retrofit avoided cost rates in DEC Exhibit 12 and DEP Exhibit 12. Duke explains that the forecast data it will use to calculate each published levelized New ESS Retrofit avoided cost rate will begin January 1, 2023 and span the length of time specified for the particular year term of the New ESS Retrofit avoided cost rate. These rates will be available until November 1, 2023. Duke Initial Statement at 54.

Duke explains that DEC and DEP are filing their respective 2, 3, 4, 5, 6, 7, 8, 9, and 10-year ESS Retrofit avoided cost rates in this proceeding pursuant to a commitment Duke made in the Sub 158 and Sub 101 dockets. *Id*. at 4.

In its Initial Statement, the Public Staff explains that Duke's ESS Retrofit avoided cost rates would be made available to QFs that: (1) are currently selling power to DEC or DEP; and (2) established a LEO or entered into a PPA prior to November 15, 2016, and wish to retrofit their facilities with energy storage. Public Staff Initial Statement at 57. The Public Staff notes that Duke used forecast data beginning on January 1, 2023 to calculate the new ESS retrofit avoided cost rates to reflect that QFs retrofitting their facilities with energy storage will proceed through the DISIS, and pursuant to DISIS timelines, will not be online until 2023 at the earliest. Public Staff Initial Statement at 58.

Ultimately, the Public Staff finds the proposed ESS Retrofit rates and eligibility requirements to be reasonable. The Public Staff also recommends that the Commission adopt the bifurcated rate proposal that the Public Staff originally raised in its Initial Comments in the Sub 158 avoided costs proceeding. According to the Public Staff, the bifurcated rate proposal would balance the need to incentivize new technologies with establishing appropriate rates by separately metering any additional output at the then-current Commission-approved avoided cost rates. The Public Staff recommends that the Commission approve both DEC's and DEP's proposed New ESS Retrofit avoided cost rates and the Public Staff's bifurcated rate proposal. *Id*. at 59.

In their Reply Comments, Duke agrees with the Public Staff that their New ESS Retrofit avoided cost rates are reasonable and that the Commission should be approved, and additionally note that no other intervenor submitted comments on this issue. Duke Reply Comments at 47. Regarding the Public Staff's bifurcated rate proposal, Duke explains that the proposal would require utilities to separately meter any additional energy output from the original facility and compensate the additional output at the then-current

Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of the pre-existing PPA. Duke states that it opposed this proposal in the Sub 158 proceeding, and all parties, including the Public Staff, acknowledged potential challenges to implementation. Duke explains that the Commission's Sub 158 Order found that it was "premature" to rule on the Public Staff's proposal absent further "investigation" into the issues." *Id*. at 47-48. Accordingly, Duke explains, beginning in May 2020, Duke worked in good faith with stakeholders to achieve technical and regulatory solutions for modifying existing facilities to add energy storage and reached a compromise consensus regarding the Public Staff's proposed bifurcated rate proposal. Specifically, Duke explains, the parties agreed that: (1) the addition of storage to an existing facility will be accomplished through amendment of the existing PPA, rather than negotiating a new PPA; and (2) metering of the storage addition will be covered by an AC-connected configuration, although integration of DC connected systems will be allowed once DC revenue-grade meters are available and tested. The addition of a second meter will allow Duke to implement a bifurcated rate as proposed by the Public Staff. Accordingly, subject to the caveat that only AC-connected configurations can currently be metered, Duke supports the Public Staff's request for the Commission to approve the bifurcated rate proposal. *Id*. at 48.

Discussion and Conclusions

In both the 2018 Sub 158 Order and the Commission's June 14, 2019 Order Approving Revised Interconnection Standard and Requiring Reports and Testimony in Docket No. E-100, Sub 101, the Commission directed the parties to address issues related to the addition of energy storage at an existing QF, including, but not limited to, developing a streamlined process for interconnecting ESS to existing generation sites and organizing a stakeholder proceeding to address other related issues. 2018 Sub 158 Order at 137 (Ordering Paragraph 31); 2019 Sub 101 Order at 65 (Ordering Paragraph 7). Through the stakeholder process, DEC and DEP subsequently developed their ESS Retrofit Study Process and filed it with the Commission.

On August 17, 2021, the Commission ordered DEC and DEP to, among other things, establish and file "the procedure for how a QF establishes eligibility for the avoided cost rate or methodology applicable to the output of the energy storage addition." Retrofit Storage Order. DEC and DEP set out their proposal for this process in their September 29, 2021 Compliance Filing filed in both the Sub 158 and Sub 101 dockets. ESS Retrofit Compliance Filing, Attachment C (Procedure for Energy Storage System Retrofit at an Existing QF Generation Site to Establish Eligibility for Avoided Cost Rates), Docket. Nos. E-100, Sub 101 and E-100, Sub 158 (N.C.U.C. Sept. 29, 2021). The Commission approved Duke's proposal on May 12, 2022 in Docket Nos. E-100, Sub 101 and E-100, Sub 158. Order Granting Waivers to Implement Energy Storage System Expedited Study Process and Approving Process to Establish Eligibility of Avoided Cost Rates for Retrofit Energy Storage Systems, Nos. E-100, Sub 101, E-100, Sub 158 (N.C.U.C. May 12, 2022). Accordingly, Duke's new ESS retrofit avoided cost rates as well as the Public Staff's bifurcated rate proposal are ripe for Commission consideration in this docket.

Based on the foregoing evidence and the entire record, the Commission finds that DEC's and DEP's respective 2, 3, 4, 5, 6, 7, 8, 9, and 10-year New ESS Retrofit avoided cost rates available to Interconnection Customers proposing to retrofit an ESS at an existing generation site, as set forth in DEC Exhibit 12 and DEP Exhibit 12, are reasonable and hereby approved. The Commission also commends the parties for working together to reach agreement regarding the Public Staff's bifurcated rate proposal and again finds the proposal to be reasonable. As noted in the Retrofit Storage Order, the Public Staff's bifurcated rate proposal was "accepted by the Commission [in the Sub 158 Order] and would allow the facility to continue to receive compensation at the rates established in its PPA for the existing generating facility but would receive compensation for the output of the energy storage system at the avoided cost rate current at the time the energy storage added." Accordingly, the Commission approves the Public Staff's bifurcated rate proposal and finds that: (1) the addition of storage to an existing facility will be accomplished through amendment of the existing PPA, rather than negotiating a new PPA; and (2) metering of the storage addition will be covered by an AC-connected configuration, although integration of DC connected systems will be allowed once DC revenue-grade meters are available and tested. The Commission directs Duke to file in Docket No. E-100, Sub 158 an update advising the Commission when DC revenue-grade meters become available for use for energy storage retrofits.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting this finding of fact is found in the verified Joint Comments and Proposed Rates of WCU and New River, the Initial Comments of the Public Staff and of Appalachian Voices, the Reply Comments of New River, and the entire record herein.

In their Joint Comments, WCU and New River note that, effective January 1, 2022, both companies began taking power supplies from Carolina Power Partners (CPP) instead of DEC. WCU and New River expect to update their avoided cost rates later in 2022 upon a completion of a cost-of-service study. WCU and New River propose to offer variable rates based upon their wholesale cost of power that reflects the wholesale rates paid to CPP. WCU and New River propose three avoided cost rates as follows: (1) small power producers or cogenerators that desire to receive the demand credit (Rate SPP Demand); (2) aggregate customer loads where the customer foregos the demand credit (Rate SPP No Demand); and (3) customer loads where the provider desires a long-term avoided cost rate (SPP-Fixed). WCU and New River also note that neither utility offers net metering, and both have limited QFs operating on their systems. WCU and New River initially filed but later withdrew a $25.00 monthly administrative fee proposal for Rate SPP Demand and a $8.25 monthly administrative fee for its Rate SPP No Demand.

Appalachian Voices filed comments on February 24, 2021, explaining that, based on discovery responses from New River, the newly proposed fees were copied from WCU without any additional analysis or justification. Appalachian Voices Initial Comments at 6-9. Appalachian Voices raised concerns regarding the fees, which would serve as a strong disincentive for customer-sited renewable energy. *Id.*

On March 1, 2022, New River filed Amended Rates and Contracts waiving its proposed administrative fees. In waiving the fees, New River cited: (1) its prior practice of not charging administrative fees; (2) the de minimis impact of the waiver; (3) the small number of SPP customers; (4) SPP customer expectations; (5) a lack of recent cost basis analysis; and (6) the expectation that New River will propose a net billing rate later this year, at which time reimbursement to SPPs would change. New River Amended Rates at 2.

Appalachian Voices filed a letter on March 11, 2022, supporting New River's March 1 filing and confirming that the Amended Rates and Contracts addressed its fee concerns in this proceeding. Appalachian Voices Response at 1.

In Reply Comments, Public Staff supports New River's Amended Rates and Contracts filing as "a reasonable continuation of prior practices, given the relatively small number of customers involved and the issues raised by Appalachian Voices." Public Staff Reply Comments at 8.

The Commission concludes, based upon the foregoing and the entire record herein, that WCU's and New River's proposed rates should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DENC shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs contracting to sell 1 MW or less capacity. The standard ten-year levelized rate option should include a condition making contracts 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. That DENC shall continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's 2006 Sub 106 Order and most recently restated in the 2018 Sub 158 Order;

3. That DEP, DEC, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) 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 or not there is an active solicitation underway, 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;

4. That DEC's and DEP's Schedule PP, as presented in DEC Exhibit 1 and DEP Exhibit 1 to the Duke Initial Statement and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

5. That DEC, DEP, and DENC shall continue to calculate avoided capacity costs using the Peaker Method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3) and shall evaluate whether to continue the use of the Peaker Method in the next biennial avoided cost proceeding;

6. That DENC shall continue to calculate rates that reflect the elimination of the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network;

7. That DEC and DEP shall use a PAF of 1.04 in their respective avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

8. That DEC and DEP shall use a PAF of 2.0 for run-of-river hydro QFs that are subject to the standard offer;

9. That DENC shall use a PAF of 1.07 in its avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

10. That DEC, DEP, and DENC shall address the inclusion of solar and wind generator outage data in the PAF calculation in future avoided cost proceedings;

11. That DEC and DEP shall calculate their avoided energy costs using forward natural gas prices for no more than 8 years before transitioning to fundamental forecasts;

12. That DEC and DEP shall utilize the fuel hedging adjustment as proposed for the purposes of this proceeding;

13. That DENC's proposed input assumptions to be used in determining its proposed energy rates, including those related to fuel forecasting methodology, fuel

hedging activities, and the LMP adjustment shall be used in calculating DENC's rates in this proceeding;

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;

15. That the solar integration services charges proposed by DEC ($1.05 per MWh) and DEP ($2.26 per MWh) shall be used in calculating rates in this proceeding as a decrement to DEC's and DEP's avoided energy rates, which shall apply prospectively for the duration of the contract, consistent with the conclusions reached in this Order;

16. That Duke shall 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 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;

17. That DENC shall use a re-dispatch charge of $1.87/MWh in calculating DENC's rates in this proceeding;

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;

19. That for the purposes of calculating avoided capacity rates in this proceeding, DEC should use seasonal allocation weightings of 96% for winter and 4% for summer, and DEP should use seasonal allocation weightings of 100% for winter;

20. That DENC shall continue to use the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons approved in Docket No. E-100, Sub 158 in calculating rates in this proceeding;

21. That DENC shall continue to use the rate design approved in Docket No. E-100, Sub 158 in calculating rates in this proceeding;

22. That DEC's and DEP's standard offer PPA, as presented in DEC Exhibit 3 and DEP Exhibit 3 to the Duke Initial Statement and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

23. That DEC's and DEP's Terms and Conditions, as presented in DEC Exhibit 4 and DEP Exhibit 4 to the Duke Initial Statement and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

24. That DEC's and DEP's Notice of Commitment Form, as presented in DEC Exhibit 6 and DEP Exhibit 6 to the Duke Initial Statement and in Exhibit 1 to the Duke Reply Comments, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

25. That DENC's proposed revisions to its LEO Forms, as modified by its June 29, 2022 filing, and proposed Retrofit Storage LEO Forms, as modified, are approved;

26. That DEC's and DEP's ESS retrofit avoided cost rates, as presented in DEC Exhibit 12 and DEP Exhibit 12 to the Duke Initial Statement and discussed in this Order, are approved to be offered to QFs that commit to retrofit their existing generating facility to co-locate an ESS;

27. That Duke shall file in Docket No. E-100, Sub 158 an update advising the Commission when DC revenue-grade meters become available for use for energy storage retrofits;

28. That WCU's and New River's proposal to offer all QFs contracting to sell 1 MW or less variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track CPP's wholesale charges to WCU and New River are approved; and

29. That within 30 days after the date of this Order, the Utilities shall file revised versions of their rate schedules and standard contracts in redline and clean versions that comply with the rate methodologies and contract terms approved in this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations are raised.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd day of November, 2022.

NORTH CAROLINA UTILITIES COMMISSION

Erica N Green

Erica N. Green, Deputy Clerk