



April 23, 2021

Ms. Kim Campbell  
Chief Clerk  
North Carolina Utilities Commission  
430 North Salisbury Street  
Raleigh, NC 27603

Re: Docket No. E-100, Sub 167  
In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility  
Purchases from Qualifying Facilities – 2020  
**Proposed Order of the Southern Alliance for Clean Energy, North Carolina  
Clean Energy Business Alliance, and the North Carolina Sustainable Energy  
Association**

Dear Ms. Campbell,

In connection with the above-referenced docket, please find enclosed for filing the Proposed Order of the Southern Alliance for Clean Energy, North Carolina Clean Energy Business Alliance, and the North Carolina Sustainable Energy Association. Pursuant to Commission Rule R1-25(c), a Microsoft Word version of the proposed order will be emailed to [briefs@ncuc.net](mailto:briefs@ncuc.net). Please let us know if you have any questions or if there are any issues with this filing.

Please let me know if you have any questions or if there are any issues with this filing.

Respectfully yours,

/s/ Peter H. Ledford

/s/ Benjamin Smith

On Behalf of the North Carolina Sustainable Energy Association

/s/ Nick Jimenez

On Behalf of the Southern Alliance for Clean Energy

/s/ Karen Kemerait

On Behalf of the North Carolina Clean Energy Business Alliance



**CERTIFICATE OF SERVICE**

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing documents by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 23rd day of April, 2021.

/s/ Peter H. Ledford  
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STATE OF NORTH CAROLINA  
UTILITIES COMMISSION  
RALEIGH

DOCKET NO. E-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	<b>PROPOSED ORDER OF THE</b>
Rates for Electric Utility Purchases from	)	<b>SOUTHERN ALLIANCE FOR</b>
Qualifying Facilities – 2020	)	<b>CLEAN ENERGY, NORTH</b>
	)	<b>CAROLINA CLEAN ENERGY</b>
	)	<b>BUSINESS ALLIANCE, AND</b>
	)	<b>THE NORTH CAROLINA</b>
	)	<b>SUSTAINABLE ENERGY</b>
	)	<b>ASSOCIATION</b>

BY THE COMMISSION: This is the streamlined 2020 biennial proceeding held by the North Carolina Utilities Commission (“Commission”) pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (“PURPA”), 18 U.S.C. 824a-3, and the Federal Energy Regulatory Commission (“FERC”) regulations implementing those provisions,<sup>1</sup> which delegated to the Commission certain responsibilities for determining each utility’s avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings are also held pursuant to N.C. Gen. Stat. § 62-156, which requires the Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in N.C. Gen. Stat. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC establish the responsibilities of FERC and state regulatory authorities, such as this

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<sup>1</sup> Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30, 128 (1980); *see also* 45 Fed. Reg. 12,214 (1980).

Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring the purchase and sale of electric power by electric utilities to cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become “qualifying facilities” (“QFs”), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

With respect to electric utilities subject to state jurisdiction, FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to FERC’s rules.

The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest to be held

by the Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs that they interconnect. The Commission also has reviewed and made determinations regarding other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also follows the mandate of N.C. Gen. Stat. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that “no later than March 1, 1981, and at least every two years thereafter” the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in FERC regulations regarding factors to be considered in the determination of avoided cost rates. House Bill 589 (“H.B. 589”), S.L. 2017-192, made significant revisions to the state implementation of PURPA, while still leaving a number of implementation issues to the Commission for consideration in these biennial proceedings.

On August 13, 2020, the Commission issued its Order Establishing Biennial Proceedings, Requiring Data, and Scheduling Hearing (“Order”). Pursuant to the Order, Duke Energy Carolinas, LLC (“DEC”), Duke Energy Progress, LLC (“DEP”) (together, “Duke Energy”), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (“Dominion” or “DENC”), Western Carolina University (“WCU”), and Appalachian State University, d/b/a New River Power and Light (“New River”) were made parties to these proceedings.

The following parties filed Petitions to Intervene that were granted by the

Commission: North Carolina Sustainable Energy Association (“NCSEA”), North Carolina Clean Energy Business Alliance (“NCCEBA”<sup>2</sup>), Carolina Industrial Group for Fair Utility Rates I (“CIGFUR I”), Carolina Industrial Group for Fair Utility Rates II (“CIGFUR II”), Carolina Industrial Group for Fair Utility Rates III (“CIGFUR III”) (CIGFUR I, CIGFUR II, CIGFUR III, collectively, “CIGFUR”), Southern Alliance for Clean Energy (“SACE”), and NC Small Hydro Group (“Hydro Group”). Participation of the Public Staff was recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On October 20, 2020, Duke Energy and Dominion filed Duke Energy Carolinas, LLC, Duke Energy Progress, LLC’s and Dominion Energy North Carolina’s Notification of Intended Compliance with N.C. Gen. Stat. 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements, and Request to Prospectively Modify Timing of Biennial Proceedings (“Request for Continuance”).

On October 30, 2020, the Commission entered the commensurate Order Granting Continuance and Establishing Reporting Requirements (“Order Granting Continuance”) allowing for a modified proceeding. The Commission acknowledged the intention of Duke Energy and DENC, as outlined in their October 20, 2020 filing, to comply with N.C. Gen. Stat § 62-156(b) by filing “streamlined” 2020 avoided cost filings that would update the inputs in their avoided cost energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Commission’s April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 158 (“Sub 158 Order”), the 2018 biennial avoided cost proceeding

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<sup>2</sup> NCCEBA recently assumed the prior functions of the South Carolina Solar Business Alliance and is now named the Carolinas Clean Energy Business Association (“CCEBA”). However, it will be referred to as NCCEBA throughout because that is the name it made the relevant filings under.

(“Sub 158”). The Commission also provided instructions for addressing additional issues remaining from the Sub 158 Order that would not be addressed in this “streamlined” proceeding, but rather expressed its expectation that Duke Energy and DENC would make significant effort to address all of the Sub 158 additional issues with interested stakeholders and directed Duke Energy and DENC to file a proposal of how they would address each unresolved item and provide updates at least every 45 days informing the Commission of their progress.

On November 2, 2020, DENC filed its Initial Statement and Exhibits and its confidential avoided cost information. On November 2, 2020 Duke Energy filed a Joint Initial Statement and Exhibits and confidential avoided cost information.

On November 24, 2020, the Commission ordered that the public hearing in this docket would be held remotely and required Duke Energy, Dominion, WCU, and New River to publish notices of public hearing.

On December 7, 2020, pursuant to the Order Granting Continuance, Dominion filed its Dominion Letter Regarding Sub 158 Additional Issues Initial Report (“Dominion Sub 158 Issues Letter”) and Duke Energy filed the Joint Progress Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (“Duke Sub 158 Progress Report”).

On December 16, 2020, DENC filed corrected versions of its November 2, 2020 filings.

On December 22, 2020, WCU and New River filed Joint Comments and Proposed Rates.

On December 23, 2020, DENC filed Corrected Revised Exhibit DENC-16 from its December 16, 2020 filing.

On December 29, 2020, the Public Staff filed a Motion for Extension for Filing of Comments. No party indicated that it objected to the Public Staff's request for an extension. On December 30, 2020, the Commission granted the Motion for Extension for Filing of Comments. The Commission extended the date for the parties to file initial comments to on or before January 25, 2021, extended the date for parties to file reply comments to on or before February 26, 2021, and extended the date for parties to file proposed orders to on or before March 26, 2021.

On January 21, 2021, Duke Energy filed its Second Joint 45-Day Progress Report and DENC filed its Sub 158 Additional Issues Status Update.

On January 25, 2021, Public Staff filed confidential and redacted versions of its Initial Comments. On January 25, 2021, SACE, NCCEBA, and NCSEA filed confidential and redacted versions of its Joint Initial Comments.

On January 28, 2021, DENC filed an Affidavit of Publication to serve as proof of publication of the Public Notice as required in the Commission's November 24, 2020 Order. On February 15, 2021, Duke Energy filed an Affidavit of Publication to serve as proof of publication of the Public Notice as required by the Commission's November 24, 2020 Order.

On February 2, 2021, DENC, CIGFUR, NCSEA, Duke Energy, SACE, NCCEBA, the Public Staff, and Hydro Group consented to a remote hearing. On February 10, 2021, the Public Staff filed a Motion to Cancel Public Hearing, and no party indicated objection to the Motion. On February 11, 2021, the Commission granted the Motion and issued an Order canceling the public hearing.

On February 12, 2021, Duke Energy filed supplemental public and confidential



versions of Revised Energy Rate Calculations and Updated Avoided Energy Rates.

On February 22, 2021, SACE, NCCEBA, and NCSEA filed their Joint Motion for Extension of Time to file reply comments. No party objected to the Joint Motion for Extension of Time. On February 23, 2021, the Commission granted the Joint Motion for Extension of Time. The Commission extended the date for the parties to file reply comments to on or before March 5, 2021.

On February 26, 2021, DENC filed for reference public and confidential versions of all public contracts between VEPCO/DENC and qualifying facilities.

On March 5, 2021, DENC filed Reply Comments. On March 5, 2021, the Public Staff filed confidential and redacted versions of Reply Comments. On March 5, 2021, Duke Energy filed Reply Comments. On March 5, 2021, SACE, NCSEA, and NCCEBA filed Joint Reply Comments.

On March 8, 2021, Duke Energy filed its Third Joint 45-Day Progress Report and DENC filed its Sub 158 Additional Issues Status Update.

On March 17, 2021, Duke Energy filed the Additional Affidavit of Publication.

On March 17, 2021, Duke Energy filed their Joint Motion for Extension of Time for parties to file proposed orders. No party objected to the Joint Motion for Extension of Time. On March 19, 2021, the Commission granted the Joint Motion for Extension of Time. The Commission extended the date for the parties to file proposed orders to on or before April 9, 2021.

On March 17, 2021, Duke Energy filed the Attachment to its Third Joint 45-Day Progress Report filed on March 8, 2021.

On April 5, 2021, Duke Energy filed their Joint Motion for Additional Extension

of Time for parties to file proposed orders. No party objected to the Joint Motion for Additional Extension of Time. On April 5, 2021, the Commission granted the Joint Motion for Additional Extension of Time. The Commission extended the date for the parties to file proposed orders to on or before April 23, 2021.

On April 22, 2021, Duke Energy filed its Fourth Joint 45-Day Progress Report and DENC filed its Sub 158 Additional Issues Status Update.

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

### **FINDINGS OF FACT**

1. Consistent with past avoided cost proceedings, it is reasonable and appropriate for DENC to continue to use two standard avoided cost rate schedules, one based on a fixed price for the duration of the contract term, Schedule 19-FP, and one based on an hourly energy purchase price derived from the day-ahead locational marginal price at the PJM-defined nodal location nearest to the QF, Schedule 19-LMP.

2. DENC's continued use of the rate design agreed upon by DENC and the Public Staff, as presented in the rebuttal testimony of DENC witness Petrie in the Sub 158 proceeding to calculate avoided energy under Schedule 19-FP, is reasonable and appropriate.

3. DENC's use of the PLEXOS utility production costing model to calculate the avoided energy costs contained in Schedule 19-FP is reasonable and appropriate.

4. DENC's input assumptions for its PLEXOS utility production costing model are reasonable and appropriate.

5. DENC's continued use of blended 18-month forward commodity prices is reasonable and appropriate, and DENC's input assumptions for those forward commodity prices are reasonable and appropriate.

6. DENC's continued use of the North Carolina Service Area, rather than the complete Dominion Zone, to determine locational energy value is appropriate. DENC's continued use of the Day Ahead Locational Marginal Price peaker method to determine the avoided cost of energy under Schedule 19-LMP, as determined in previous avoided cost proceedings, is reasonable and appropriate.

7. DENC's continued inclusion of the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy costs is appropriate.

8. DENC's assumptions and the Black-Scholes option pricing method to determine fuel hedging benefits are reasonable and appropriate.

9. DENC's proposal for solar QF avoidance protocols for the solar re-dispatch charge, as modified by the suggestion of the Public Staff, is reasonable and appropriate, and DENC's continued use of a \$0.78/MWh re-dispatch charge as approved in the Sub 158 Order for purposes of this filing under Schedule 19-FP is reasonable and appropriate.

10. DENC's inclusion of RGGI-based carbon dioxide ("CO<sub>2</sub>") prices, and its omission of a federal CO<sub>2</sub> price, are reasonable and appropriate.

11. DENC's continued elimination of the line loss adder, as determined in the Sub 158 Order, is reasonable and appropriate in this limited proceeding. This will be re-evaluated in the 2021 avoided cost proceeding.

12. DENC's continued use of the peaker method to calculate the avoided

capacity cost rates for the Schedule 19-FP rate schedule is reasonable and appropriate.

13. DENC's continued use of the metric Equivalent Availability ("EA"), representing the availability of the unit(s) during the defined period, and accounts for unit unavailability caused by planned, maintenance, and forced outages, to determine the Performance Adjustment Factor ("PAF"), and its continued use of a PAF of 1.07 are reasonable and appropriate.

14. DENC's revised standard contracts and terms and conditions are reasonable and appropriate for the purpose of this limited proceeding, except as modified in this Order.

15. Consistent with past avoided cost proceedings, it is reasonable and appropriate for Duke Energy to continue to utilize Schedule PP for its avoided cost rate schedule in the two Duke Energy territories in North Carolina.

16. Consistent with past avoided cost proceedings, Duke Energy's continued use of the peaker method in this proceeding to determine avoided energy and capacity costs is reasonable and appropriate.

17. Duke Energy's continued use of modeling and assumptions consistent with those used in its most recent 2020 biennial integrated resource plans ("IRPs") and/or utilized Commission-approved inputs and methodologies adopted in the Sub 158 proceeding, to streamline the issues before the Commission in fixing Duke Energy's standard avoided cost rates is reasonable and appropriate.

18. Duke Energy's continued calculation of avoided capacity costs using the peaker method includes 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. This calculation is reasonable and appropriate for this proceeding. Duke

Energy's continued calculation of avoided capacity costs will be re-examined as necessary in future avoided cost proceedings.

19. It is reasonable and appropriate for Duke Energy to have developed its avoided capacity rates consistent with the methodology that it used in the Sub 158 proceeding and that the Commission approved in the Sub 158 Order as appropriately implementing N.C. Gen. Stat. § 62-156(b)(3). As identified in Duke Energy's recently filed 2020 IRPs, DEC's next avoidable undesignated capacity need occurs in 2026, while DEP's next avoidable undesignated capacity need occurs in 2024.

20. It is reasonable and appropriate for DEC and DEP to include provisions in their Schedules that recognize that in certain circumstances, QFs fueled by swine waste, poultry waste, and hydro power, receive capacity payments calculated regardless of the Duke Energy's demonstrated need for future capacity reflected in their IRPs.

21. It is reasonable and appropriate for Duke Energy not to include avoided cost rates for hydro small power producers in excess of 1 MW in their standard offer for only this proceeding. The Commission agrees that Duke Energy must comply with N.C. Gen. Stat. § 62-156(b)(3) with respect to negotiated PPAs with eligible hydro QFs greater than 1 MW but equal to or less than 5 MW.

22. Duke Energy's avoided CT Unit Capital Costs have been calculated consistently with the methodology approved in the 2018 Avoided Cost proceeding.

23. In light of the Order Granting Continuance and the streamlined nature of this proceeding, it is reasonable and appropriate for Duke Energy to use the same equivalent availability ("EA") metric approved in the Sub 158 Order to develop a PAF capacity multiplier, and the updated PAF finding of 1.06 by Duke is reasonable. Pursuant

to the Sub 158 Order, Duke Energy shall address the appropriateness of using the Equivalent Unplanned Outage Rate (“EUOR”) metric in the 2021 avoided cost proceeding.

24. It is reasonable and appropriate for Duke Energy to include a 2.0 PAF in DEC’s and DEP’s standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW. Duke Energy negotiated the Hydro Stipulation in good faith, and its terms and conditions were based both upon North Carolina’s policy of supporting small hydro QFs and the relatively small and finite amount of small hydro capacity in the state.

25. More broadly, Duke Energy’s treatment of treat run-of-river hydro QFs consistent with Commission precedent and the Hydro Stipulation is reasonable and appropriate.

26. Duke Energy’s continued reliance on the PROSYM generation production cost modeling platform to derive its system marginal energy costs is reasonable and appropriate, and its inputs were appropriate except as discussed herein.

27. In light of the Order Granting Continuance and the streamlined nature of this proceeding, it is reasonable and appropriate for Duke Energy to continue to calculate its 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 for this streamlined proceeding. This will be subject to further review in future avoided cost proceedings.

28. It is reasonable and appropriate for Duke Energy to continue to use the Black-Scholes method to determine fuel hedging value for renewables for this proceeding, but Duke Energy shall research other methods, such as those discussed by Witness Tom Beach, and present a comparison in the 2021 avoided cost proceeding.

29. It is appropriate for Duke Energy to retain a line loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP at this time.

30. Duke Energy shall evaluate and report on any geographical concentrations of back-feeding substations and whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate.

31. For proposed distribution-connected QFs that are not eligible for Schedule PP, Duke Energy may continue to consider whether the QF's energy output would backfeed the substation and inject energy onto the transmission system. Duke Energy shall 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. Line loss adder will continue to be evaluated in the next avoided cost proceeding.

32. In light of the Order Granting Continuance and the streamlined nature of this proceeding, and Duke Energy's lack of progress in updating its solar integration services costs ("SISC") analysis, it is reasonable and appropriate for the SISC approved in the Sub 158 Order to remain in effect at \$1.10/MWh for DEC and \$2.39/MWh for DEP for QFs establishing a legally enforceable obligation ("LEO") prior to November 1, 2021.

33. Duke Energy should work with interested parties to reach consensus to the maximum extent possible on the SISC prior to their November 1, 2021 filing.

34. It is reasonable and appropriate for Duke Energy continue to evaluate real-time pricing and other tariffs that could provide more granular rate structures and price signals to QFs for the benefit of customers and to make recommendations in its 2021 avoided cost filing.

35. It is reasonable and appropriate for Duke Energy continue to use the avoided energy and capacity rate designs outlined in the Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and the Public Staff in Docket No. E-100, Sub 158 (“Sub 158 Rate Design Stipulation”) for Schedule PP.

36. The modifications to Schedule PP tariffs, reflecting updated avoided cost rates, are reasonable and appropriate.

37. The limited modifications to Schedule PP PPAs and Terms and Conditions, as approved in the Sub 158 Order, are reasonable and appropriate.

38. The limited revisions to Duke Energy’s standard offer PPA forms are reasonable and appropriate.

39. Duke Energy’s limited ministerial changes to the Schedule PP standard offer Notice of Commitment form, to state that QFs submitting the Notice of Commitment form after the filing of updated rate schedules shall be eligible for the new avoided cost rates filed in this docket, and to make clear that the effective date of the Notice of Commitment form and establishment of a LEO thereunder will be used for purposes of determining the priority of QFs for eligibility for Schedule PP under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW), are reasonable and appropriate.

40. Duke Energy shall revise the production forecast reporting requirements to only apply to QFs greater than one MW in capacity.

41. Duke Energy shall continue using existing Henry Hub differentials and shall delete and not rely upon assumptions of pipeline infrastructure that do not currently exist or are not yet being built.



42. Duke Energy used two private fundamentals forecasts for the calculation of its avoided energy rates and did not include a publicly available forecast. Duke shall recalculate its avoided energy costs using at least one publicly available Henry Hub forecast.

43. Duke Energy undervalued the long-term physical hedge against natural gas price volatility provided by renewable QFs. Duke shall recalculate its avoided energy costs using a more accurate value for natural gas hedging.

44. Duke Energy's choice of combustion turbine for capacity prices is outdated. Duke shall recalculate its avoided capacity costs using the more accurate assumption of an advanced turbine model.

45. Duke Energy's avoided costs omit the cost of CO2 emissions. Duke Energy shall recalculate its avoided costs using the IRPs' Base scenario for carbon emission costs starting in 2025. The Commission will revisit the "known and verifiable" standard in the 2021 avoided cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 & 2**

The evidence supporting these Findings of Fact is found in DENC's Initial Statement and the Initial Comments of the Public Staff.

#### **SUMMARY OF THE EVIDENCE**

As in the 2018 Avoided Cost Case, DENC filed two standard avoided cost rate schedules in this proceeding, Schedule 19-FP and Schedule 19-LMP.

As provided in Section I of the DENC's proposed Schedule 19-FP and Schedule 19-LMP, and consistent with the Sub 158 Order, DENC proposes to make these rate schedules 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 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 proceeding after this Docket No. E-100, Sub 167.

The two proposed rate schedules—Schedule 19-FP and Schedule 19-LMP—are based upon a fixed price for the duration of the contract term and an hourly energy purchase price derived from the day-ahead locational marginal price at PJM-defined nodal location nearest to the QF, respectively.

In the Sub 158 Order, the Commission found it appropriate to require DENC to use the rate design agreed upon by DENC and the Public Staff as presented in the rebuttal testimony of DENC witness Petrie in calculating avoided energy (and capacity) rates in that proceeding. The Commission found that the revised rate design, which became Schedule 19-FP, provided QFs with more granular price signals to incentivize QFs to better match DENC’s generation needs. For purposes of calculating energy rates, that rate design comprised 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 avoided energy cost rates for purposes of this proceeding. The total avoided energy cost rate reflected in Schedule 19-FP is based on the sum of four components: (1) PLEXOS derived avoided energy rates; (2) Congestion Impact; (3) Fuel Hedging Benefit;

and (4) Re-dispatch costs. PLEXOS will be discussed in more depth below.

In the proposed Schedule 19-LMP, energy prices are based on the hourly PJM Day Ahead Locational Marginal Price (“DA LMP”) as discussed more fully below.

In its Initial Comments, the Public Staff noted that DENC proposed two avoided cost rate schedules, Schedule 19- LMP based on LMPs and Schedule 19-FP based on the peaker method. The practice of offering dual tariffs was first established in the 2006 proceeding. Further, the Public Staff noted that in prior proceedings, DENC had stated that this methodology allows QFs to be paid for delivered energy and capacity equivalent to what DENC would have paid PJM if the QF generator had not been generating. The transparency of the LMP method allows QFs to make prudent decisions regarding the running of their facilities to maximize their revenues, and it more accurately reflects DENC’s actual avoided energy costs. Schedule 19-FP offers QFs fixed levelized avoided energy and avoided capacity payments for variable and 10-year terms.

#### DISCUSSION AND CONCLUSIONS

The Commission finds reasonable DENC’s proposed two standard avoided cost rate schedules, Schedules 19-FP and 19-LMP. The Commission finds persuasive the determinations made in the prior Sub 158 proceeding. The Commission further agrees with DENC that it is reasonable and appropriate to utilize two separate rate schedules, one the more traditional contract type and also a day-ahead type, as proposed by DENC here. The Commission further finds that given the nature of this streamlined proceeding and the “inputs-only” discussion, it need not complicate this proceeding by litigating the underlying avoided cost rate tariff proposals methodologies.

Accordingly, the Commission determines that DENC’s proposed 19-FP and 19-

LMP proposed rate schedules are reasonable and appropriate and shall be implemented subject to the remainder of this order.

### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 8**

The evidence supporting these Findings of Fact is found in DENC's Initial Statement, the Initial Statement of the Public Staff, the Initial Comments of SACE, NCCEBA, and NCSEA, and DENC's Reply Comments.

#### SUMMARY OF THE EVIDENCE

According to DENC's Initial Statement, PLEXOS is a utility production costing model leased from Energy Exemplar that DENC uses to calculate the avoided energy costs contained in Schedule 19-FP. Since the 2018 Avoided Cost Case, DENC has moved from using the PROMOD model that it used in previous years to the PLEXOS model. The PLEXOS model incorporates an 8,760 hourly load profile, which is different from the previously used PROMOD model, which incorporated a "typical week by month" profile. DENC claims that the dispatch from the PLEXOS model utilizing the short-term ("ST") module better accounts for dispatch constraints on thermal generating units.

While the production costing model DENC is using has changed, the process for developing the avoided energy costs is the same as in previous filings. The starting point for the analysis is the PLEXOS base case, including the generation expansion plan "B" from DENC's most recent IRP. This first simulation is referred to as the "without QF" case. The new units in the generation expansion plan are listed in the attached Exhibit DENC-5. A second PLEXOS case, referred to as the "with QF" case, was run with an additional QF resource. The additional QF resource was modeled with the following operating parameters: 100 MW unit, must-run, 85% availability, and zero energy cost. All

other assumptions from the base case remained the same. The difference in the annual system production costs between the “with QF” and “without QF” cases represents the DENCs forecasted avoided energy costs.

According to DENC, the input assumptions included in this modeling process can be placed into three major categories. The first category includes purchase power assumptions and non-utility generator sources. DENC relies on ICF International, Inc. (“ICF”) to provide an independent forecast of commodity prices, including gas, coal, oil, power, capacity, and emissions. The power prices utilized by the PLEXOS model are priced at the PJM Interconnection, L.L.C. (“PJM”) Dominion Zone (“DOM Zone”), which represent the average of all the nodes located in the zone. According to DENC, there is no intra-zonal congestion included in the base energy price forecast. The second category includes assumptions regarding generating unit operating characteristics. The third category reflects the variable (or dispatch) costs of the generating units (including fuel, variable O&M, and emission and start-up costs). The resulting output from PLEXOS was used to calculate DENC’s levelized long-term fixed energy rates under Schedule 19-FP for each of the nine pricing periods approved in the Sub 158 Order.

The Public Staff notes DENC’s method for calculating avoided energy costs for Schedule 19-FP is largely consistent with methods employed in the 2018 Proceeding. DENC used PROMOD to calculate avoided costs in the 2018 Proceeding, but switched to PLEXOS, a utility production costing model leased from Energy Exemplar, to calculate the avoided energy costs contained in Schedule 19-FP in this proceeding. In its initial filing, DENC also cites the various improvements as the reason for the switch from PROMOD to PLEXOS. The least cost dispatch is modeled in combination with the utility’s energy sales

and peak demand forecasts using DENC's generation expansion plan "B" included in its 2020 IRP. DENC incorporated a "without QF" case and a "with QF" case using the resulting output to determine the avoided energy rates. The Public Staff has reviewed the PLEXOS inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs.

DENC's proposes to continue its use of blended 18-month forward commodity prices and include the same forward commodity prices it previously used in the Sub 158 proceeding. Regarding the forward commodity prices (for fuels, power, and emission allowances), consistent with past practice, DENC developed the avoided energy cost rates using 18 months of forward market prices, 18 months of blended prices (blend of market and ICF prices), and then ICF fundamental forecast prices exclusively starting in month 37 of the forecast period. In the 2018 Avoided Cost Case, the Public Staff found the Company's approach to developing avoided energy cost rates to be reasonable, and the Commission found that the input assumptions used by the Company to determine its avoided energy cost rates were appropriate.

Regarding DENC's continued use of the North Carolina Service area, rather than the complete Dominion Zone, in the October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 148 ("Sub 148 Order"), the Commission accepted DENC's proposal to adjust its avoided energy rates to reflect the locational energy value of its North Carolina service area as opposed to the entire DOM Zone. The Commission agreed with the Company that as supply increases, locational marginal prices ("LMPs") decrease, and vice versa, and that the avoided cost of added generation or load reduction is therefore equal to the LMP at the location where the

generation or load reduction occurs. The Commission recognized that as more generation is added to DENC's North Carolina service area, a location that the Commission recognized was already "saturated with narrowly concentrated distributed generation," the congestion and marginal loss components increase, reflecting the cost of enabling this generation to "flow" to locations where it is needed to serve load. The Commission concluded that the significant cost of congestion between DENC's North Carolina nodes and the DOM Zone supported using the LMPs associated with the locations where QFs are generating to correctly calculate avoided cost rates. The Commission therefore concluded that DENC's proposal to adjust its avoided energy rates to account for the lower value of generation in its North Carolina service area, as compared to the DOM Zone overall, was appropriate, and that the adjustment would allow rates to better reflect the Company's actual avoided system energy cost, as required by PURPA and the Federal Energy Regulatory Commission's ("FERC") implementing regulations.

In the Sub 158 Order, based on evidence presented by DENC regarding the continued disparity in LMPs in its service territory, the Commission concluded that DENC's continued inclusion of the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy costs was appropriate. DENC has accordingly adjusted the avoided energy cost rates proposed in this proceeding to reflect the fact that LMPs in the North Carolina area of its service territory continue to be lower than the LMPs for the DOM Zone.

The Public Staff notes that the proposed Schedule 19-LMP energy is based on the hourly PJM Day Ahead LMPs at the nearest PJM-defined nodal location to the QF. To derive the cents per kWh price, the dollars per MWh PJM Dominion Zone Day-Ahead

hourly LMPs are divided by 10 and then multiplied by the QF's hourly net generation. The Public Staff further states that DENC maintains that the LMP methodology offers several benefits including transparency to all parties. In prior proceedings, DENC has stated that this methodology allows QFs to be paid for delivered energy and capacity equivalent to what DENC would have paid PJM if the QF generator had not been generating. The transparency of the LMP method allows QFs to make prudent decisions regarding the running of their facilities to maximize their revenues, and it more accurately reflects DENC's actual avoided energy costs.

DENC has also been consistent in its fuel hedging. In its December 31, 2014 Order Setting Avoided Cost Input Parameters in Docket No. E-100, Sub 140 ("Sub 140 Phase 1 Order"), the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. In Phase 2 of that proceeding, the Commission required the Utilities to utilize the Black-Scholes Model, or a similar model, to determine the fuel price hedging value of renewable generation. For the energy rates that it is proposing in this proceeding, and consistent with its proposals in the 2016 and 2018 Avoided Cost Cases, DENC has again used the Black-Scholes option pricing method to determine the fuel hedging benefits that was proposed by the Public Staff in its June 22, 2015 Initial Statement in Docket No. E-100, Sub 140. Consistent with that approach, DENC inputs current Henry Hub gas pricing data into the option pricing model, resulting in a call option value of approximately \$0.2985 per million British thermal units (mmbtu) and a put option value of \$0.2958/mmbtu. The net option price, or difference between the call and put option values, of \$0.0027/mmbtu represents the estimated fuel price hedging benefit. Multiplying the \$0.0027/mmbtu by a gas combined-cycle plant heat



rate of 7.0 mmbtu/MWh results in a fuel price hedging value of \$0.02/MWh, which is assumed constant for all years of the Schedule 19-FP contract.

The Public Staff notes that consistent with the Sub 158 proceeding, DENC included avoided fuel hedging values in its avoided energy calculations based on the Black-Scholes option pricing model, using an estimate for gas price volatility, a risk free interest rate, and the strike price, which yielded a net option price of \$0.0027mmbtu.

More specifically with regard to Black-Scholes DENC has used the same Black-Scholes option pricing method to determine the fuel hedging benefits that was proposed by the Public Staff in its June 22, 2015 Initial Statement in Docket No. E-100, Sub 140. Consistent with that approach, the Company input current Henry Hub gas pricing data into the option pricing model, resulting in a call option value of approximately \$0.2985/mmbtu and a put option value of \$0.2958/mmbtu. The net option price, or difference between the call and put option values, of \$0.0027/mmbtu represents the estimated fuel price hedging benefit. Multiplying the \$0.0027/mmbtu by a gas combined-cycle plant heat rate of 7.0 mmbtu/MWh results in a fuel price hedging value of \$0.02/MWh, which is assumed constant for all years of the Schedule 19-FP contract.

In its initial comments, the Public Staff did not object.

In their initial comments, SACE, NCCEBA, and NCSEA pointed out that the statute requires the avoided cost of energy to include both “the expected cost of fuel and other operating expenses” for alternative sources and, separately, “the expected security of the supply of fuel for the utilities’ alternative power sources.” N.C. Gen. Stat. § 62-156(b)(2). The groups believe that the Commission properly implemented this directive when it required Duke Energy to account for the “added fuel price stability gained through

each year” as a result of purchases from a renewable QF under a long-term PPA.

SACE, NCCEBA, and NCSEA argued that while use of the Black-Scholes Model to determine the fuel hedging value provided by qualifying facilities that use renewable energy meets the minimum requirements of the Commission’s order and has been litigated in prior Commission proceedings, a more accurate methodology would better comply with the Sub 158 Order’s requirement for an appropriate fuel hedging value and with the underlying statute.

Citing the Crossborder Energy Report, SACE, NCCEBA, and NCSEA explained that the Black-Scholes Model undervalues the long-term physical hedge against natural gas price volatility provided by a long-term renewable QF fixed-price PPA, since those PPAs provide added fuel price stability over the full term of the contract, or 10 years, whereas the Black-Scholes Model simulates buying sequential options to purchase an 8-month supply of natural gas at a fixed price over a 10-year period. Because the price of each successive option depends on the then-prevailing market price, the Black-Scholes Model updates the price of natural gas fuel 15 times over the course of the 10-year period. As a result, SACE, NCCEBA, and NCSEA submit that the Black-Scholes Model does not fully capture the added fuel price stability gained over the course of a long-term fixed-price PPA with a renewable QF. SACE, NCCEBA, and NCSEA acknowledged that this could be a methodological issue rather than a compliance issue, and that if it is, the issue should be examined in the full proceeding beginning in November.

In its reply comments, DENC noted that SACE, NCCEBA, and NCSEA’s recommendations were directed at Duke Energy but opposed the recommendations and the Crossborder Energy Report to the extent that the recommendation is considered to apply

to DENC. DENC argued that the alternative methods suggested by the Crossborder Report are not reasonable approaches to calculating avoided hedging costs for North Carolina due to several factors, including DENC's belief that the methods discussed in the Crossborder Report are based on outdated data and would result in inappropriately inflated hedging values, thereby drastically and unreasonably increasing avoided energy cost rates. In addition, the Commission concluded in the 2014 avoided cost proceeding and again in the Sub 158 Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities and as a result the use of ten or twenty year hedging periods as suggested by the Crossborder Report is far in excess of what is appropriate. Since DENC's typical natural gas hedge financial hedge program could extend approximately 18 to 24 months in the future, DENC argued that it is appropriate that DENC calculate assumed avoided hedging costs using this time frame.

#### DISCUSSION AND CONCLUSIONS

DENC's adoption of the PLEXOS utility production cost modeling arguably falls outside the streamlined proceeding that DENC and Duke Energy requested in this proceeding. However, as stated by DENC in its Initial Statement, the underlying process for developing the avoided cost rate is unchanged and the modeling inputs are consistent with those set forth and approved in prior proceedings. For these reasons, and because of the support of the Public Staff and lack of opposition from other parties, the Commission finds reasonable and appropriate DENC's PLEXOS modeling technique to develop Schedule 19-FP and further finds the modeling input assumptions therein reasonable and appropriate, as well.

Regarding forward commodity prices, the Commission again finds 18 months of

forward market prices, 18 months of blended prices (blend of market and ICF prices), and then ICF prices exclusively starting in month 37 of the forecast period as an appropriate way to determine future commodity prices. The Commission finds persuasive the arguments of the Public Staff in making this determination.

As determined in prior proceedings, the Commission agrees with DENC's LMP position. Namely, this is a transparent method that allows a more real-time and allows QFs to benefit and also the utility to make decisions that are most prudent for ratepayers. For these reasons, the Commission finds the LMP method is reasonable and appropriate. Furthermore, the use of nodal techniques, rather than the entirety of the DOM zone, has repeatedly shown to be a more accurate pricing mechanism. The Commission again approves this, as well. Also, as accepted in the Sub 158 Order, DENC's continued inclusion of the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy costs is appropriate.

The Commission continues to recognize that, as stated in its Sub 140 Phase 1 Order, "there are fuel price hedging benefits associated with solar generation" and therefore "[i]t is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation." Sub 140 Phase 1 Order, p. 42; *see also* Sub 158 Order, p.102. The Commission's determination of the avoided cost of energy to the utility must include "the expected costs of the additional or existing generating capacity which could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities' alternative power sources." N.C. Gen. Stat. § 62-156(b)(2). Pursuant to this requirement, in the Sub

158 Order the Commission directed Duke to “include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA.” It specified that the method used must value “the added fuel price stability gained through each year of the entire term of the QF power purchase agreement.” Sub 158 Order, p. 62.

The Commission recognizes that in previous avoided cost proceedings both Duke Energy and Dominion have proposed a hedge value of 0.028 cents per kWh in accordance with a Memorandum of Understanding with the Public Staff filed on February 2, 2016. In its Sub 158 Order, the Commission accepted as reasonable and appropriate for that proceeding DENC’s proposed hedging value of \$0.30/MWh, which it assumed constant for all years of the Schedule 19-FP contract. The revised hedge value of \$0.02/MWh that DENC proposes, \$0.00002/kWh, represents a very significant reduction from these prior values. This proposed value was calculated using the Black-Scholes option pricing method and updated Henry Hub gas pricing data, both of which and the Commission finds reasonable and appropriate for this proceeding. However, the Commission has difficulty understanding how an update to Henry Hub gas pricing data could cause such a dramatic shift in the hedge value and will require DENC to clarify this in a filing within 30 days of this Order.

The Commission finds that the method of calculating the fuel price hedging benefits associated with renewable generation is a methodological issue and under the Order Granting Continuance is outside the scope of this “streamlined” proceeding. However, in light of the very significant reduction in the updated hedge value and the concern with the

Black-Scholes method raised by SACE, NCCEBA, and NCSEA and discussed in the Crossborder Energy Report, the Commission will require DENC to reevaluate the Black-Scholes method in its filing in the 2021 avoided cost proceeding and compare it to alternative methods of valuation.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9**

The evidence supporting this Finding of Fact is found in DENC's Initial Statement, the Initial Statement of the Public Staff, DENC's Reply Comments, and the Joint Reply Comments of SACE, NCCEBA, and NCSEA.

#### **SUMMARY OF THE EVIDENCE**

In the Sub 158 Order, the Commission directed DENC to file a proposed protocol for avoidance of the re-dispatch charge. The Commission approved the proposed re-dispatch charge, modified pursuant to the Company's agreement with the Public Staff to be \$0.78/MWh. In its initial filing, DENC proposes to continue to apply this redispatch charge ("RDC") for purposes of this proceeding. DENC proposes that the re-dispatch charge can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device ("ESD"). DENC defines an ESD as a component of a QF facility that uses energy storage technology, including but not limited to battery storage.

DENC proposes to calculate the reduction in variability as the percent reduction in variability from a case without storage to a case with storage. For each case, on a calendar year basis, DENC will calculate variability as the sum of the hourly absolute output variance from a QF-provided generation forecast. The percent reduction in variability will be calculated by subtracting the ratio of the variability of the case with storage to the variability of the case without storage from one. DENC will then calculate a credit to the

re-dispatch charge as follows: (1) the percent reduction in variability multiplied by (2) the re-dispatch charge rate multiplied by (3) the total calendar year output (MWh) of the case with storage.

DENC proposes that to be eligible for the re-dispatch cost reduction, a QF 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"). 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 will utilize the previously provided forecast to calculate the re-dispatch charge reduction credit. Every April, DENC will calculate the re-dispatch cost reduction using the prior calendar year forecast and metered data. DENC will provide the re-dispatch charge reduction as a line-item credit with the first payment following the April calculation.

In its initial comments, the Public Staff states that it did not currently object to the Protocol as proposed. The Public Staff states that re-dispatch costs incurred by DENC due to intermittent QFs are largely driven by variance between their day-ahead projected load and their real-time actual load, and that the variance occurs because DENC does not bid QF output into the PJM energy and capacity markets; rather, DENC uses a complex combination of forecasting tools to estimate the total load it must secure from PJM as a Load Serving Entity ("LSE"). Accordingly, the calculation attempts to estimate the amount of load reduction that is provided by QF output.

Although it does not expressly object, the Public Staff raises concerns with the RDC. The Public Staff believes that the ideal method to ensure that the avoided re-dispatch

costs match the RDC credit issued is for Controlled Solar Generators (“CSG”) to provide more frequent forecasts (weekly or day-ahead), which DENC would then incorporate into its day-ahead load calculations, which the Public Staff dubbed “Option 1.” However, the Public Staff confirmed that DENC does not use the hourly output forecasts provided by CSGs in estimating total QF load reduction because the current process for estimating QF load reduction is built into the load forecasting model and would require significant effort to modify. In addition, the number of QFs that would seek to avoid the RDC is currently unknown. For these reasons, the Public Staff agrees with DENC that it is not reasonable at this time to modify DENC’s existing load forecasting tools to incorporate QF forecasts.

The Public Staff believes that the next best method to ensure that the avoided re-dispatch costs match the RDC credit issued would be to compare actual CSG output to the QF load reduction estimate utilized in the DENC LSE load forecast, dubbing this “Option 2.” This method would negate the need for the CSG to provide forecasts and would instead evaluate CSG variability against DENC’s estimates for QF load reduction, which is directly tied to the error between the day-ahead load forecasts and real-time load requirements. However, DENC currently cannot extract the QF load reduction estimate from the total load forecast, making this analysis impossible. Due to this limitation, DENC cannot share the QF load reduction estimate with CSGs; thus, a CSG would not be able to modify its output to match DENC’s load reduction estimate. Thus, the RDC credit calculated for each CSG would not be in the CSG’s control.

With these preferred options unavailable, the Public Staff believes that the Protocol proposed by DENC is a reasonable “third best” option for estimating the reduction in re-dispatch costs incurred by CSGs, because DENC’s QF load reduction estimates incorporate



QF output from the prior day (in addition to other variables) and over time, as a CSG consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate will take that predictability into account.

However, the Public Staff raises two related concerns. First, it questions the value of energy shifting. It points out that the RDC credit depends not only on how the CSG dispatches the ESD, but also what type of forecast is provided. The Public Staff anticipates that a CSG which intends to use its ESD to shift energy from off-peak to on-peak hours will likely wish to provide a forecast that anticipates this energy shifting dispatch, rather than a forecast that anticipates simply "smoothing" the CSG's output. According to the Public Staff's calculations, a CSG that forecasts and engages in energy shifting will be eligible for a significantly higher RDC than a CSG that only engages in smoothing. The Public Staff believes it is unclear if ratepayers actually benefit more from energy shifting dispatch than smoothing dispatch. Second, the Public Staff is concerned that CSGs might be able to "game" their forecasts and output to obtain excessive RDC credits. The Public Staff recommends that DENC monitor the types of forecasts and the ESD dispatch behavior for CSGs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of CSGs in DENC's service territory in its future avoided cost filings.

In its reply comments, DENC recognizes the Public Staff's concerns, and reaffirms that it believes its proposed RDC Avoidance Protocol is a reasonable proxy for estimating the reduction in re-dispatch costs incurred by CSGs. DENC states that it does not object to the Public Staff's recommendation that DENC monitor CSG forecasts and behavior and include that information and an analysis of actual solar volatility of CSGs in DENC's

service territory in its future biennial avoided cost filings. However, DENC's acquiescence is conditioned on limiting its monitoring and reporting obligation to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs. DENC also clarifies that it would plan to monitor this information on an annual basis. DENC also did not object to the Public Staff's proposal that it specifically address CSGs seeking RDC avoidance in each future fuel rider proceeding, providing the specific facility(ies) and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on CSGs seeking to avoid the RDC, subject to the same limitation to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs.

In their joint reply comments, SACE, NCCEBA, and NCSEA disagree with the Public Staff. Addressing the first concern, SACE, NCCEBA, and NCSEA point out that shifting energy to peak times generally benefits customers more because it displaces costly on-peak generation, and if a CSG earns a higher RDC as a result of engaging in energy-shifting, that is a natural result of the design and application of the RDC. In addition, because the RDC reduces the avoided-cost rate that a solar QF receives in order to compensate the utility for fuel and purchased energy costs associated with integrating the variable energy, if a controlled solar QF that uses its storage not just to smooth output but to shift energy operates in a controlled manner and does not cause those integration costs, then there is no reason to deduct those costs from the QF's avoided-cost compensation, and indeed, deducting the RDC in that scenario improperly yields a rate less than avoided cost.

Addressing the Public Staff's second concern, SACE, NCCEBA, and NCSEA point out that it is unclear how the Public Staff thinks CSGs could "game" their forecasts; the concern seems to be that a QF would artificially increase its solar-only variability and/or

reduce its combined variability. SACE, NCCEBA, and NCSEA point out that the likelihood of a QF undertaking such a ploy and not being detected is virtually non-existent. The strategy could work at most only in a QF's first year of operation, and would likely be detected even then. Further, if a QF developed a forecast for the coming year that was substantially different from its actual output the previous year, that too would be detected. Finally, estimating output for any year should be straightforward given standard inputs such as nameplate capacity, technology, orientation, public direct normal irradiance ("DNI") data, and how the plant will be operated, such as using storage to shift output.

#### DISCUSSION AND CONCLUSIONS

The Commission finds reasonable DENC's proposed solar QF avoidance protocols for the solar re-dispatch charge, as modified by the suggestion of the Public Staff, as well as DENC's continued use of a \$0.78/MWh re-dispatch charge as approved in the Sub 158 Order for purposes of this filing under Schedule 19-FP.

The Commission is not persuaded that there is any likelihood that CSGs that use their ESD to engage in energy-shifting rather than merely smoothing will receive excessive credit for avoiding the RDC. The RDC reduces the avoided-cost rate that a solar QF receives in order to compensate the utility for fuel and purchased energy costs associated with integrating the variable energy. If a CSG that uses its storage not just to smooth output but to shift energy operates in a controlled manner and therefore does not cause such integration costs then there is no basis on which to deduct those costs from the QF's avoided-cost compensation.

Nor is the Commission persuaded, on the evidence in this proceeding, that there is significant risk that CSGs will "game" DENC's formula or their forecasts. At this point in

time, this risk appears entirely speculative and undefined. Furthermore, SACE, NCCEBA, and NCSEA offer reasons that any such gaming likely would be readily detectable and partly for that reason unlikely to occur.

However, the Commission acknowledges the broader issue raised by the Public Staff, that there might be better methods of measuring the credit a CSG should receive for avoiding the RDC. No party, including DENC, objected to the Public Staff's request that DENC monitor, for CSGs that attempt to avoid the RDC, such CSG's forecasts and behavior and include that information and an analysis of actual solar volatility of CSGs in DENC's service territory in its future biennial avoided cost filings. DENC did not object on the condition that its monitoring and reporting obligation be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs, noting that it would monitor his information on an annual basis.

Accordingly, the Commission will direct DENC to conduct such monitoring, subject to DENC's conditions stated above, and include that information and an analysis of actual solar volatility of CSGs in DENC's service territory in its future biennial avoided cost filings. This monitoring and reporting requirement shall not entail any additional administrative burden on CSGs.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10**

The evidence supporting this Finding of Fact is found in DENC's Initial Statement, the Initial Statement of the Public Staff, DENC's Reply Comments, and the Joint Reply Comments of SACE, NCCEBA, and NCSEA.

#### **SUMMARY OF THE EVIDENCE**

DENC calculated its proposed avoided energy rates using its Alternative Plan B

from its 2020 IRP filing in Docket No. E-100, Sub 165. Alternative Plan B takes into account 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 CO<sub>2</sub> price used by DENC to calculate its proposed avoided energy rates also includes a federal CO<sub>2</sub> price in addition to the RGGI CO<sub>2</sub> price in years 2026 and beyond. This is consistent with Alternative Plan B in DENC's 2020 IRP.

In its initial comments, the Public Staff agrees that Alternative 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 RGGI, effective January 1, 2021. It also agrees that the RGGI carbon price is sufficiently "known and verifiable" based on current law, and that 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.

However, the Public Staff raises two concerns with the CO<sub>2</sub> price included in DENC's avoided energy rates. First, the CO<sub>2</sub> price used in the production cost model for avoided energy exceeds the RGGI-only CO<sub>2</sub> price forecast used in the IRP in years 2020 through 2023. DENC states that this deviation is due to the use of RGGI market futures pricing used in the first 18 months; these market prices are then blended into their fundamental forecast, consistent with how DENC forecasts natural gas prices. The Public Staff finds this explanation to be reasonable.

Second, the CO<sub>2</sub> price also includes a federal CO<sub>2</sub> price in addition to the RGGI CO<sub>2</sub> price in years 2026 and beyond. The Public Staff finds this federal price insufficiently "known and verifiable," citing the Sub 140 Phase II Order at pp.8, 42-44. The Public Staff

recommends that DENC re-run its production cost model using a RGGI price forecast without a federal CO2 price, and file revised avoided energy rates.

DENC does not object to the Public Staff's recommendation; it re-ran the PLEXOS model using the RGGI price forecast but no federal CO2 price and filed a revised Schedule 19-FP reflecting revised avoided energy rates with its reply comments. DENC states that if the Commission agreed with the Public Staff on this issue, it does not object to using these revised avoided energy rates. It clarifies that the RGGI Only price used in the IRP is a price forecast made under the influence of a federal CO2 price, and the RGGI Only price decline in years 2026 through 2030 is due to downward pressure on emissions resulting from the federal CO2 price, and as a result the RGGI Only price forecast in absence of the federal CO2 price will actually slightly increase in years 2026 through 2030.

In its reply comments, the Public Staff states that it finds DENC's revised rates appropriate for use in this proceeding.

In their joint reply comments, SACE, NCCEBA, and NCSEA state that they represented to DENC that they do not oppose these revised rates, which they did at the urging of the Public Staff.

#### DISCUSSION AND CONCLUSIONS

The Commission affirms that DENC was correct to calculate its proposed avoided energy rates using its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165. However, the Commission accepts DENC's alternative calculation omitted a federal CO2 cost, in light of the fact that DENC has already performed the calculation and parties do not oppose it, including the Public Staff, even though the revision increases rates slightly.

The Commission addresses the two different CO<sub>2</sub> prices in turn. First, the Commission finds that DENC should include the forecast RGGI price of CO<sub>2</sub> emissions. Like most other costs, the future cost of CO<sub>2</sub> emissions allowances in RGGI is not a fixed quantity, but a forecast. However, this makes the cost no less real. The “known and verifiable” standard was never intended to exclude future CO<sub>2</sub> costs simply because they cannot be known exactly in advance. Second, for reasons noted above, the Commission finds DENC’s omission of a federal CO<sub>2</sub> price reasonable and appropriate for this proceeding. The Commission will revisit the “known and verifiable” standard in the 2021 avoided cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11**

The evidence supporting this Finding of Fact is found in DENC’s Initial Statement and the Initial Statement of the Public Staff.

#### **SUMMARY OF THE EVIDENCE**

As stated in DENC’s Initial Statement, in the Sub 148 Order, the Commission approved DENC’s proposal to eliminate from its avoided energy rates the 3% adder that had historically been included based on the assumption that distributed generation from QFs would be less than load on interconnected circuits, thus permitting DENC to reduce or eliminate losses arising from centrally-located generation. In the Sub 158 Order, the Commission found that power backflow on substations in DENC’s North Carolina service territory from solar generation on the distribution grid continued to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated, and that it was appropriate that the Company continue not to include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network. For

purposes of this filing, the Company's avoided energy rates continue to reflect the elimination of the line loss adder. DENC notes in its Reply Comments it plans to update its line loss study for purposes of its November 2021 biennial avoided cost filing.

The Public Staff supports the continued removal of a line loss adder. The Public Staff notes for the same reasons articulated in the Sub 148 Order, it is appropriate for DENC to continue to have its line loss adder removed from its standard offer avoided costs rates. According to the Public Staff, DENC demonstrated that the amount of "back feed" from renewable generation occurring and expected to continue to occur on the DENC system justifies the removal of a line loss adder. The Public Staff will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings, and recommends that the Commission direct the utilities to continue to file information to support the removal/inclusion of the line loss adder in their proposed avoided cost rates in future avoided cost proceedings.

#### DISCUSSION AND CONCLUSIONS

Consistent with the findings in the Sub 148 and Sub 158 proceedings, the Commission finds reasonable and appropriate the continuing absence of line loss adder for DENC. The Commission finds the reasoning made by the Public Staff and DENC persuasive, but also notes that DENC has noted it will examine it again in the 2021 proceeding. The Commission believes this is appropriate and requests such examination be filed with the Commission with the initial filing for the 2021 Avoided Cost Proceeding in such a manner to provide transparency to review the line loss adder decision. Namely, the Commission seeks to determine that all potential benefits of distributed solar are being adequately reflected in the filing. Moreover, with advances in inverter technology and also



battery storage ancillary benefits to the grid, the Commission wishes to determine that the line loss adder determination found here is still correct.

### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12**

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

#### SUMMARY OF THE EVIDENCE

As it has since the 2012 biennial avoided cost proceeding (Docket No. E 100, Sub 136), DENC proposes to use the peaker method to calculate the avoided capacity cost rates for the Schedule 19-FP rate schedule. The outline of this method was set forth more explicitly in the Sub 140 Phase 1 Order.

In the Sub 140 Phase 1 Order, the Commission determined that the utilities "should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data." The Commission further clarified that the installed cost of a CT should include:

- the cost of land for a greenfield site;
- transmission interconnection costs, but exclude network upgrade costs;
- economies of scale to include the cost benefits associated with building multiple CTs at a single site, up to four units, but exclude economies of scope for the cost benefits associated with building multiple CTs at the same time;
- a reasonable contingency adder; and
- tailoring to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Consistent with the method used in the compliance filing in the 2018 Avoided Cost

Case, DENC used the applicable costs of the Greenville combined cycle power plant as the basis for the CT equipment costs. DENC states that these costs are current and verifiable and represent DENC's actual procurement costs of CT equipment related to a power plant that came online in December 2018.

For the remaining costs, including construction and owner costs, DENC used the PJM cost of new entry estimates, which is based primarily on the "PJM Cost of New Entry for Combustion Turbine and Combined Cycle Plants With June 1, 2022 Online Date" report prepared by The Brattle Group and Sargent & Lundy, dated April 19, 2018 (the "Brattle Study"). Because the CT equipment costs are estimated separately, as discussed above, the estimated equipment costs for the GE 7HA turbine equipment used in the Brattle Study were removed. To tailor the Brattle Study results to meet the requirements of the Parameters Order, the Company made the following additional adjustments:

- adjusted the EPC construction labor and equipment costs to reflect economies of scale related to the construction of a two-unit CT site;
- adjusted sales tax to reflect rates applicable for VA;
- adjusted electric and gas interconnection costs to reflect costs expected for a CT constructed by the Company in VA or NC;
- adjusted fuel costs for startup to reflect the cost of gas and oil during start up testing and to account for PJM energy revenues; and
- eliminated financing fees as financing costs are included later in the CT annual carrying cost calculations.

Since the Brattle Study assumes a CT with a COD of 2022, the construction and owner cost estimate was de-escalated for a 2021 COD. DENC presented a hypothetical CT

build in its Initial Statement with a total cost of the Hypothetical CT (CT equipment costs plus construction and owner costs) equaling to \$188.7 million. Based on an annual average capacity of 324.2 MW for the CT facility, the total installed (nominal) cost of a CT is equal to \$582.1/kW. This value is then adjusted to include the carrying costs related to the build-out of a two unit CT site, resulting in a total installed cost of \$592.5/kW.

The resulting installed cost of a new CT facility does not include financing costs. This installed cost value is converted to annual fixed costs inclusive of financing costs (and added to the fixed operating and maintenance costs of the CT), allocated to seasons, divided by the applicable on-peak hours, and then levelized, to determine the avoided capacity cost rates. As noted in its Initial Statement, DENC also continued the same practice of seasonal allocation of CT Costs using the Sub 158 proceeding's rates of 45% summer, 40% winter, and 15% shoulder. Finally, DENC identified its first avoidable capacity in 2023.

The Public Staff noted that DENC's calculation of avoided capacity costs for Schedule 19-FP is based on the installed cost of a CT and is consistent with the installed cost of a CT utilized in its 2020 IRP. The Public Staff further noted that similar to the approach taken by DENC in the 2018 Proceeding, DENC made adjustments based on its Greensville Combined Cycle ("CC") Plant. DENC's Greensville-specific modifications focused on the extraction of the CT cost portion from the overall CC plant. DENC made additional cost adjustments to the data from the 2018 Brattle Study to reduce the cost of the CT, other equipment, labor costs, Virginia sales tax rate, fees, contingency costs, financing costs, and gas interconnection costs by assuming a shorter pipeline lateral. Ultimately, the Public Staff states that DENC's capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates are reasonable for the

determination of DENC's avoided capacity rates.

#### DISCUSSION AND CONCLUSIONS

DENC laid out its peaker method as the foundation for its Schedule 19-FP rates. As noted by the Public Staff, the peaker method utilized by DENC is consistent with past avoided cost proceedings and is reasonable and appropriate for use by DENC in this avoided cost proceeding. The questions related to methodology will be examined in the 2021 avoided cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13**

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

#### SUMMARY OF THE EVIDENCE

In Sub 148 Order, the Commission ruled that it would "require the Utilities to address the PAF and to support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for the utility fleets in total in [their] initial filings" in this biennial avoided cost proceeding. DENC proposes to use the metric Equivalent Availability ("EA") to determine PAF in its 2018 initial statement because according to DENC EA represents the availability of the unit(s) during the defined period, and accounts for unit unavailability caused by planned, maintenance, and forced outages. In the Sub 158 Order, the Commission approved DENC's resulting proposed PAF of 1.07. DENC proposes to continue to apply the 1.07 PAF for this filing.

#### DISCUSSION AND CONCLUSIONS

DENC's continued use of the metric EA, representing the availability of the unit(s) during the defined period that accounts for unit unavailability caused by planned,

maintenance, and forced outages, to determine the PAF, and its continued use of a PAF of 1.07 are reasonable and appropriate.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14**

The evidence supporting this Finding of Fact is found in DENC's Initial Statement.

##### SUMMARY OF THE EVIDENCE

According to DENC's Initial Statement, DENC filed Schedule 19-FP and Schedule 19-LMP standard contracts and terms and conditions. In addition to making minor edits to the standard contracts to update docket numbers, DENC is also proposing limited additional provisions that contemplate the incorporation of energy storage components in QF projects. DENC proposes these changes because of the increased likelihood that new QF projects eligible for rates and terms under this biennial proceeding may choose to incorporate an energy storage component in their project designs.

DENC proposes to include at a new Exhibit G an Energy Storage Device Addendum, which will provide DENC with basic information about the storage component of a QF project that proposes to include a battery or other storage component in its design. It will also provide basic requirements for such storage components that are associated with a QF facility eligible for compensation under these agreements.

DENC also proposes to add a provision to Article 7 of its standard offer contracts to provide that any material alteration to a QF facility shall require the prior written consent of DENC. By "material alteration," DENC means a modification to the QF facility that renders the facility description specified in the contract inaccurate in any material sense as determined by DENC in a commercially reasonable manner, including but not limited to the addition of an Energy Storage Device or a modification that increases the output of the

facility. However, repair or replacement of equipment (including solar panels) with like-kind equipment, which does not increase the facility's capacity or decrease its capacity by more than five percent, shall not be considered a material alteration. The Commission approved this provision in Sub 158 Order for use in Duke Energy's standard avoided cost contracts.

Finally, DENC proposes administrative updates to its LEO Forms as approved in the Sub 148 Order to update the contact information for DENC's Power Contracts group.

Exhibit DENC-8 is a clean copy of the Company's proposed Schedule 19-FP standard contract. Exhibit DENC-9 is a blackline showing the proposed changes to the Company's Schedule 19-FP standard contract as approved in the 2018 Avoided Cost Case and submitted with the Company's May 15, 2020, compliance filing in the 2018 Avoided Cost Case. Exhibit DENC-10 is a clean copy of the Company's proposed Schedule 19-LMP standard contract. Exhibit DENC-11 is a blackline showing the proposed changes to the Company's Schedule 19-LMP standard contract as approved in the 2018 Avoided Cost Case and submitted with the Company's May 15, 2020, compliance filing in the 2018 Avoided Cost Case. Exhibits 12 through 15 are clean and blacklined versions of the Company's small and large QF LEO Forms.

#### DISCUSSION AND CONCLUSIONS

With the exception of Exhibit G, DENC's revised standard contracts and terms and conditions are reasonable and appropriate for the purpose of this limited proceeding. While the Commission agrees with DENC that there is an increased likelihood that new QF projects eligible for rates and terms under this biennial proceeding may choose to incorporate an energy storage component in their project designs, Exhibit G goes beyond

the “streamlined” proceeding requested by Duke Energy and DENC and is more appropriately addressed in the proceeding to examine the Sub 158 Additional Issues later this year. Further, Article 7 of DENC’s standard offer contract and DENC’s definition of “material alteration” is appropriate and reasonable.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15**

The evidence supporting this Finding of Fact is found in Duke Energy’s Initial Statement, the Initial Statement of the Public Staff, the Joint Initial Comments of SACE, NCCEBA, and NCSEA, and the February 12, 2021, supplemental filing by DEC and DEP.

#### **SUMMARY OF THE EVIDENCE**

Duke’s Schedule PP pays QFs on a volumetric rate basis (i.e., both avoided energy and capacity is paid on a \$/MWh basis versus a separate fixed payment for capacity). The rates are designed to credit QFs for avoided energy supplied during predesignated on-peak and off-peak hours. Energy credits are applicable to all QF energy supplied during the year and vary for the designated on-peak, premium-peak and off-peak hours in a day. Capacity credits are applicable to all QF energy supplied during the designated capacity payment hours. In the 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. The Public Staff’s initial comments on Duke Energy’s Schedule PP rate design conclude that the proposed rate design “compl[ies] with the Commission’s [Sub 148 Order] directive to propose more granular rates,” but suggest that additional granularity, beyond Duke Energy’s initial proposal is “appropriate and beneficial to North Carolina ratepayers.” The Public Staff therefore proposes Duke Energy implement a three-step

methodology expanding the initial rate design and focusing on more granularly defined premium peak hours and additional shoulder month periods to further distinguish rates in more critical summer and winter seasons as compared to DEC and DEP's initially proposed rate design. Duke Energy filed the Sub 158 Rate Design Stipulation addressing the agreement on appropriate avoided energy and avoided capacity rate design methodologies. Overall, the Sub 158 Rate Design Stipulation's avoided cost rate designs were generally consistent with the initial designs offered by both Duke Energy and the Public Staff, but sought to better balance the need for a granular rate design with providing Schedule PP customers clear and consistent price signals through the term of customers' contracts. The 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 and DEP's avoided energy and capacity rates.

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 that represent the hours most likely to have capacity value. Paying QFs for capacity on a per-kWh basis is consistent with the approach Duke Energy has historically utilized with respect to QF rate design under prior vintages of Schedule PP. The Public Staff and Duke Energy agreed in the Commission-approved Sub 158 Rate Design Stipulation to utilize seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé Solar Capacity Value Study, and the Companies have continued to use the seasonal allocations approved in the Sub 158 Order.

As approved in the Sub 158 Order, the Schedule PP capacity rate design offers three distinct pricing periods to reflect the marginal capacity value to customers during each



period. The pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the winter months of December, January, February, and March. No capacity payments apply during the remaining months. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. The seasonal months and three capacity pricing periods are the same for DEC and DEP. Duke Energy has adopted the same seasonal allocation of capacity value approved in the Sub 158 Order, which is heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. As approved in the Sub 158 Order, 100% of DEP's loss of load risk is assigned to the winter while 90% of DEC's loss of load risk is assigned to the winter.

The Public Staff notes in its Initial Comments that Duke does not currently offer a real time pricing ("RTP") tariff. However, in the Sub 158 Order, the Commission directed Duke to "evaluate and, if found to be appropriate, offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding." The Public Staff further notes that in the Sub 158 proceeding, the Public Staff worked with Duke to establish a more granular rate design for avoided costs. This rate design, as well as guidelines and a methodology for updating the rate design in the future to accommodate system changes, was memorialized in the Sub 158 Rate Design Stipulation. The Sub 158 Rate Design Stipulation introduced a third "shoulder" season as well as a "premium peak" pricing period for winter and summer seasons, reflecting the high cost of energy during high load hours.

The Public Staff points out that the avoided energy rates filed by DEC and DEP exhibited counterintuitive behavior in some schedules. For example, the variable rate for both DEP and DEC, and the 10-year fixed rate for DEP, all have a winter AM-peak rate that is actually lower than the winter off-peak rate, and the 10-year fixed rate for DEC has a shoulder on-peak rate that is lower than the shoulder off-peak rate. The Public Staff is concerned that this behavior was not reflective of actual avoided costs, and might in fact be an artifact of the production cost modeling; in that case, the time variant rates would not incentivize the appropriate operational behavior from dispatchable QFs. Upon investigation, the Public Staff determined that the primary driver for these counterintuitive rates was a change in the way the Duke treats start-up costs in the production cost model that is used to determine avoided energy costs. Start-up costs for certain units, particularly coal units, can be very expensive.

SACE, NCCEBA, and NCSEA argue in their Initial Comments that Duke Energy's rate design was flawed. Specifically, they stated that in the near term, Duke Energy's proposed avoided energy costs for the winter morning peak period are unreasonably low—much lower, in fact, than the avoided energy prices for surrounding off-peak hours. The proposed avoided energy costs for the winter morning peak period are very low in near-term years, which does not make sense for a peak period. This is apparently due to old production cost modeling techniques. SACE, NCCEBA, and NCSEA pointed out that the Commission should not rely on these clearly erroneous results. They argue that the avoided energy costs for this period should be averaged, for at least the first few years, with the avoided energy costs in the other winter peak and premium peak periods, so that accurate price signals are sent to QFs.

On February 12, 2021, DEC and DEP made a supplemental filing including updated Schedule PP avoided energy cost rate calculations, in response to the Public Staff's comments and the Joint Initial Comments of SACE, NCCEBA, and NCSEA regarding the treatment of unit start costs. In the supplemental filing, Duke re-ran its production cost models spreading the start costs over each unit's run time, which was consistent with the approach used in the Sub 158 proceeding. The Public Staff, SACE, NCCEBA, and NCSEA find that the revisions resolved the anomalies previously identified, and find that the revised rates are appropriate for use in this proceeding. The Public Staff also agree to continue to discuss the treatment of start costs in production cost modeling with Duke and other parties for further consideration in the November 2021 filing.

#### DISCUSSION AND CONCLUSIONS

The Commission accepts the supplemental filing made by Duke Energy, which solved the major rate design issue that is applicable to this proceeding. The remainder of Duke Energy's evidence of their rate design decisions is not opposed by the other parties and, in some cases, represents methodological issues which are not at issue in this proceeding. For these reasons, the Commission finds reasonable and appropriate Schedule PP and the underlying Duke rate design.

#### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 16-17**

The evidence supporting these Findings of Fact is found in Duke Energy's Initial Statement.

#### SUMMARY OF THE EVIDENCE

Consistent with prior biennial avoided cost filings, Duke Energy developed its avoided capacity and energy costs using the component or peaker method. The

Commission approved the continued use of the peaker methodology, or peaker method, as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs in the Sub 158 Order and a number of prior biennial avoided cost proceedings. As recognized in these prior avoided cost proceedings, the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour).

In applying the peaker method to calculate their avoided cost rates in this 2020 biennial avoided cost proceeding, Duke Energy used modeling and assumptions consistent with those used in their most recent 2020 biennial IRPs and/or utilized Commission-approved inputs and methodologies adopted in the Sub 158 proceeding, to streamline the issues before the Commission in determining the Companies' standard avoided cost rates. This approach, which should not be viewed as precedential to how Duke Energy will address such issues in future proceedings, will allow the Commission to more expeditiously review and approve the proposed standard offer avoided cost rates, while allowing Duke Energy to continue ongoing efforts to address the additional study requirements prescribed in the Sub 158 Order and to engage with interested stakeholders regarding how the State's implementation of PURPA should evolve in response to FERC's revised regulations issued in Order No 872.

No party objected to Duke Energy's use of the peaker method or using the modeling and assumptions consistent with Duke Energy's most recent 2020 biennial IRPs. It was specifically noted as the standard methodology and that was previously approved by the Commission in the Sub 158 and other prior proceeding.

## DISCUSSION AND CONCLUSIONS

As noted above, this matter is not a “live” issue in this streamlined proceeding. The use of peaker methodology is reasonable and appropriate for this proceeding but should be reevaluated in the 2021 avoided cost proceeding.

Furthermore, the intervenors in this proceeding do not object to the directive that Duke Energy utilize the modeling and assumptions consistent with those used in its most recent 2020 biennial IRP proceeding. The Commission concurs and finds this reasonable and appropriate.

### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 18-19**

The evidence supporting these Findings of Fact is found in Duke Energy’s Initial Statement and the Initial Statement of the Public Staff.

### SUMMARY OF THE EVIDENCE

In its Sub 158 Order, the Commission directed the utilities to “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.” The Commission also determined that Duke Energy appropriately calculated their avoided capacity rates consistent with N.C. Gen. Stat. § 62-156(b)(3) and directed Duke Energy to include a clear statement identifying the utility’s first year of avoidable capacity need in their 2020 IRPs.

In its Initial Statement, Duke Energy states that it has followed this direction and adhered to the same methodology recently approved by the Commission for calculating its avoided capacity rates, as further described below. It states that DEC and DEP have developed their avoided capacity rates consistent with the methodology that they used in

the Sub 158 proceeding and that the Commission approved in the Sub 158 Order as appropriately implementing N.C. Gen. Stat. § 62-156(b)(3). As identified in the recently filed 2020 IRPs, DEC's next avoidable undesignated capacity need occurs in 2026, while DEP's next avoidable undesignated capacity need occurs in 2024. Compared to the standard offer avoided cost rates approved in the Sub 158 proceeding, DEC's first year of avoidable capacity need shifted forward from 2028 to 2026, while DEP's first year of avoidable capacity need shifted outward from 2020 to 2024.

In its Initial Statement, the Public Staff notes that the Commission's Sub 148 Order found that avoided capacity value should be recognized beginning with the year that the utility's most recently filed IRP forecast shows a capacity need consistent with N.C. Gen. Stat. § 62-156(b)(3), as amended by House Bill 589. In the Sub 158 Order, the Commission found that it is appropriate for an electric utility to update its avoided capacity calculations to reflect any changes in the utility's first year of avoidable capacity need for negotiated contracts and for use in the Competitive Procurement of Renewable Energy ("CPRE") Program. The Commission stated:

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

The electric utilities' proposed avoided capacity rates provide for the payment of avoided capacity costs only when a future capacity need can be avoided. For DEC, its filed 2020 IRP indicates that the first need to be avoided is in 2026, whereas for DEP, its 2020 IRP indicates that the first need to be avoided is in 2024.

The Public Staff concludes that QFs located in DEC's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value of avoided capacity costs beginning in 2026, and QFs located in DEP's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value avoided capacity costs beginning in 2024.

### DISCUSSION AND CONCLUSIONS

As noted in this Order, the Commission has unanswered questions about Duke Energy's assumptions regarding future generation sources. Specifically, Duke Energy forecasts certain resources, but does not necessarily offer a concrete plan for how those unbuilt resources will become available. While the year of first available capacity is not contested, the Commission notes that going forward Duke Energy should identify new generation resources more specifically, such as new solar or a solar and storage mix.

The Commission is persuaded by the fact that other intervenors have not protested Duke Energy's predicted date of first need. Therefore, it is reasonable and appropriate to conclude that DEC's first need to be avoided is in 2026 and DEP's first need to be avoided is in 2024. The Commission reaffirms that the need for new capacity may not be the only reason to procure new renewable resources, particularly when those resources operate at nearly zero marginal cost and can save money for customers. Furthermore, Duke Energy's continued calculation of avoided capacity costs using the peaker method that 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 is also reasonable and appropriate for the purposes of this proceeding. This will be examined again in the 2021 proceeding, and the Commission requests that Duke provide scenarios that

match realistic generation planning scenarios.

Finally, the Commission finds Duke Energy's avoided capacity rates, which were developed with the methodology approved by the Commission in the Sub 158 proceeding, to be reasonable and appropriate. The Commission notes that this methodological question was not at issue in this limited proceeding but will be reexamined in the 2021 proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 20-21**

The evidence supporting these Findings of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff.

#### **SUMMARY OF THE EVIDENCE**

In Duke Energy's Initial Statement, Duke Energy notes that consistent with the Sub 158 Order, DEC and DEP have expressly included provisions in their Schedules that recognize that in certain circumstances, QFs fueled by swine waste, poultry waste, and hydro power receive capacity payments calculated regardless of the demonstrated need for future capacity reflected in their respective IRPs. Specifically, the Commission directed the utilities to amend their standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydro facility that has a PPA in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C. Gen. Stat. § 62-156(b)(3). As recently amended by Session Law 2019-132, N.C. Gen. Stat. § 62-156(b)(3) now provides that a future capacity need shall only be avoided in a year where the utility's most recent biennial IRP filed with the Commission has identified a projected capacity need to serve system load other than for (i) swine or



poultry waste for which a need is established consistent with N.C. Gen. Stat. § 62-133.8(e) and (f) and (ii) hydropower small power producers with power purchase agreements with an electric public utility in effect as of July 27, 2017, and the renewal of such a power purchase agreement, if the hydroelectric small power producer's facility total capacity is equal to or less than 5 MW.

Duke Energy further stated that because the standard offers are only available to QFs 1 MW and less, Duke Energy did not include avoided cost rates for hydro small power producers in excess of 1 MW in their standard offer. However, the Companies commit to complying with N.C. Gen. Stat. § 62-156(b)(3) with respect to negotiated PPAs with eligible hydro QFs greater than 1 MW but equal to or less than 5 MW.

In its Initial Statement, the Public Staff notes that in the 2018 Proceeding, the Commission directed that the:

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

The avoided capacity credits used to calculate avoided cost rates for swine or poultry QFs begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begins in the first year of a utility's capacity need. The Public Staff has reviewed these capacity credits, and other assumptions, incorporated in Duke's and DENC's proposed rates for swine and poultry QFs, and finds them reasonable for the determination of Duke's and DENC's avoided capacity credits.

## DISCUSSION AND CONCLUSIONS

Duke Energy's proposal that QFs fueled by swine waste, poultry waste, and hydro power, receive capacity payments calculated regardless of the Duke Energy's demonstrated need for future capacity reflected in their IRPs is consistent with the directive of this Commission in the prior avoided cost proceeding. Further, Duke Energy's proposal stating that Duke Energy did not include avoided cost rates for hydro small power producers in excess of 1 MW in their standard offer; but committing to complying with N.C. Gen. Stat. § 62-156(b)(3) with respect to negotiated PPAs with eligible hydro QFs greater than 1 MW but equal to or less than 5 MW is acceptable as no intervenor has objected and the reasoning is reasonable and appropriate. The Commission directs Duke Energy to comply and show proof of compliance in the next avoided cost application in 2021.

### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement and the Initial Statement of the Public Staff.

### SUMMARY OF THE EVIDENCE

In Duke Energy's Initial Statement, Duke Energy states that it calculated its avoided capacity costs based upon the U.S. EIA's published overnight cost of a CT unit, tailored to the extent needed to adapt such information to North Carolina consistent with the Commission's previous avoided cost orders. The CT overnight cost increased approximately 14% compared to the Companies' 2018 Sub 158 avoided cost filing (\$624/kW in 2018 filing versus \$713/kW in the 2020 filing) primarily due to a smaller economies of scale adjustment and a lower unit capacity rating.

In its Initial Statement, the Public Staff points out that the projected capital cost for

an installed CT is the factor that has the most impact on the avoided capacity rate. The Public Staff verified that Duke Energy used publicly available information from the U.S. Energy Information Administration (“EIA”)<sup>10</sup> specific to Region 16 (SERC Reliability Corporation / Virginia-Carolinas SRVC) to provide the overnight capital cost estimate for a single advanced F-Class CT in simple-cycle configuration for a greenfield site as modeled in the 2018 Proceeding, which was tailored to reflect the expected economies of scale associated with the gas interconnection costs for the Carolinas service area. It also found that Duke Energy’s installed cost of a CT includes the cost of using number 2 fuel oil as a backup fuel, which allowed Duke to exclude the cost of securing firm pipeline capacity for the CT.

The Public Staff tracked a number of changes in Duke Energy’s inputs. Ultimately, the Public Staff reviewed Duke Energy’s capital cost inputs, line losses, seasonal allocations, and other assumptions incorporated in DEC’s and DEP’s avoided costs and found them reasonable for the determination of their avoided capacity rates.

#### DISCUSSION AND CONCLUSIONS

The Commission concludes that Duke Energy’s avoided CT Unit Capital Costs have been calculated consistently with the methodology approved in the 2018 Avoided Cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23**

The evidence supporting this Finding of Fact is found in Duke Energy’s Initial Statement.

#### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it continued to use the equivalent

availability (“EA”) metric and to apply the same methodology approved in the Sub 158 Order to calculate the PAF capacity multiplier. It states that for purposes of this proceeding, and to avoid introducing issues that could result in more lengthy proceedings before the Commission, Duke Energy has not recommended any additional adjustments to the Commission-approved EA metric to compute the PAF, and have followed the same methodology of compiling five years of historic equivalent availability data for the entire fleet during DEC and DEP’s critical peak season months of January, February, July, and August. Based upon these calculations, DEC’s and DEP’s respective equivalent availability during this timeframe averages to approximately 94%, which supports a slightly higher PAF of 1.06 as compared to the PAF of 1.05 approved in the Sub 158 Order and in the prior Sub 148 Order. Duke Energy states that it plans to use the time between now and their next avoided cost filing to discuss the appropriateness of using the EUOR metric with the Public Staff.

#### DISCUSSION AND CONCLUSIONS

The Commission concludes that in light of the Order Granting Continuance and the streamlined nature of this proceeding, it is reasonable and appropriate for Duke Energy to use the same EA metric approved in the Sub 158 Order to develop a PAF capacity multiplier, and the updated PAF finding of 1.06 by Duke is reasonable. Pursuant to the Sub 158 Order, Duke Energy shall address the appropriateness of using the EUOR metric in the 2021 avoided cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 & 25**

The evidence supporting these Findings of Fact is found in Duke Energy’s Initial Statement and the Initial Statement of the Public Staff.

## SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy reviews the history of the 2.0 PAF for run-of-river hydro QFs without storage. In 2014, Duke Energy and the NC Hydro Group entered into a stipulation in Docket No. E-100, Sub 140 (“Hydro Stipulation”), in which the parties agreed, among other things, that Duke Energy would continue to include the previously-approved 2.0 PAF in standard offers filed at the Commission prior to December 31, 2020, to calculate the avoided cost rates for small hydro QFs of 5 MW or less through December 31, 2020. The General Assembly has subsequently amended the State’s implementation of PURPA through HB 589 in 2017 and Session Law 2019-329 to no longer designate hydroelectric generating facilities as unique small power producers, while at the same time establishing flexibility for the Companies 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. In the Sub 158 Order, the Commission directed Duke Energy to address whether the special 2.0 PAF capacity multiplier should continue for the standard offer in this biennial proceeding.

Duke Energy has included a 2.0 PAF in DEC’s and DEP’s standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW. In its Initial Statement, Duke Energy states that it negotiated the Hydro Stipulation in good faith, and its terms and conditions were based both upon North Carolina’s policy of supporting small hydro QFs and the relatively small and finite amount of small hydro capacity in the state. Duke Energy also notes that in a letter to the Commission, it outlined its intentions for the continuing applicability of terms and conditions of the Hydro Stipulation for hydro QFs 5 MW and less, namely, that it would continue to honor the 2.0 PAF for purposes of calculating

avoided cost rates in those negotiated PPAs through December 31, 2020, and have included a 2.0 PAF multiplier in the calculation of avoided capacity rates for hydro QFs without storage eligible for the standard offer, but did not agree to extend the 2.0 PAF beyond the current Hydro Stipulation's expiration at the end of 2020 due to intervening changes to PURPA implementation in North Carolina enacted by HB 589.

In its Initial Statement, the Public Staff does not recommend any further changes during this proceeding to the PAF for hydroelectric QFs with no storage capacity, but recommends that Duke, consistent with the Commission's directive in the Sub 158 Order, should address the issue of the appropriate PAF to apply in calculating capacity rates available to run-of-the-river hydro QFs as part of their initial statements filed in the next biennial avoided cost proceeding.

#### DISCUSSION AND CONCLUSIONS

The Commission concludes that it is reasonable and appropriate for Duke Energy to include a 2.0 PAF in DEC's and DEP's standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW, and more broadly, Duke Energy's treatment of run-of-river hydro QFs consistent with Commission precedent and the Hydro Stipulation is reasonable and appropriate. Recognizing Duke Energy's intention to cease applying the 2.0 PAF to these facilities, the Commission expects that Duke Energy will apply the appropriate PAF in calculating capacity rates available to run-of-the-river hydro QFs as part of their initial statements filed in the 2021 avoided cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, and Duke Energy's Reply Comments.

## SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it relied upon the PROSYM generation production cost modeling platform to derive its system marginal energy costs, which represents the forecasted energy costs that purchase from a QF would avoid.

In its Initial Statement, the Public Staff explains that PROSYM is an hourly chronological model that dispatches generating units in a least cost manner subject to various constraints such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times. The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts and the resource expansion plan from its IRP. The Public Staff reviewed the PROSYM inputs on the projected operation of Duke's generation units, including the following: variable O&M; the price forecasts for delivered natural gas, coal, oil, and uranium; the projected prices of SO<sub>2</sub> and NO<sub>x</sub> emission allowances; the projected MWh generation from renewable energy resources; projected energy purchases; and other inputs.

The Public Staff concludes that the MW capacities, heat rates, and other inputs that characterize Duke Energy's generation units are reasonably consistent with the 2018 Proceeding and are appropriate for this proceeding. However, the Public Staff states that although it believes that Duke Energy's projection of its annual energy prices are reasonable for the short-term variable energy rate, the Public Staff has concerns with Duke's projected avoided energy costs over the entire 10 years, which is used to calculate the 10-Year Fixed energy rate, due to the assumption of increased reliance on lower-priced shale gas. The Public Staff also raises a concern about winter peak energy rates that has been resolved.

In its Reply Comments, Duke Energy reviews the Public Staff's favorable conclusion and recommends that the Commission approve its avoided energy and capacity cost calculations as reasonable and appropriate for purposes of this proceeding, as well as its respective avoided energy and capacity rates.

#### DISCUSSION AND CONCLUSIONS

The Commission finds that Duke Energy's continued reliance on the PROSYM generation production cost modeling platform to derive its system marginal energy costs is reasonable and appropriate, and its inputs were appropriate except as discussed herein.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement and the Initial Statement of the Public Staff.

#### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it has developed the respective avoided energy rates by relying upon the methodology directed by the Commission to be used in the Sub 158 Order. Duke Energy states that despite the Commission's directive regarding natural gas forecasts, it believes that relying upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived from fundamental forecasts is more appropriate. Duke Energy notes a goal of "maintaining consistency" between natural gas forecast methodologies in the Companies' IRPs and avoided cost proceedings.

In its Initial Statement, the Public Staff notes that Duke Energy has incorporated forward basis natural gas prices for the first eight years, and for years nine and ten Duke has incorporated its fundamental gas price forecast, and that this approach is consistent



with the Sub 148 and Sub 158 Orders.

In its Reply Comments, the Public Staff states that, consistent with SACE, NCCEBA, and NCSEA's joint recommendations and with the Public Staff's prior positions, Duke should rely on fewer than eight years of forward natural gas market price data before transitioning to a fundamentals forecast in both the avoided cost and the IRP proceeding. The Public Staff also states that Duke should use a transition period between the forwards-only forecast and the fundamental forecast. However, given the streamlined approach to the 2020 biennial proceeding, the Public Staff accepts the natural gas price forecasts used by Duke Energy in this proceeding as consistent with the Sub 158 Order, but the Public Staff reserves the right to raise this issue in the next avoided cost proceeding.

In their Initial Comments, SACE, NCCEBA, and NCSEA state that Duke should rely on fewer than eight years of forward natural gas market price data before transitioning to a fundamentals forecast in both the avoided cost and IRP proceeding. As described in the groups' report, the use of eight years of forward market prices raises concerns about the transparency, practical applicability, and liquidity of such price data. The report also recommends the use of a transition period between the forwards-only forecast and the fundamental forecast, rather than an immediate switch from one method to the other, which would allow for a smoother transition between forecast methodologies.

#### DISCUSSION AND CONCLUSIONS

The evidence in this proceeding indicates that Duke Energy has complied with the Commission's directive in the Sub 158 Order to use "no more than eight years" of forward natural gas prices before using fundamental forecast data for the remainder of the planning period. However, notwithstanding its prior rulings on this issue, the Commission shares

the concerns of the Public Staff and SACE, NCCEBA, and NCSEA regarding the use of eight years of forward natural gas prices before using fundamental forecast data and the absence of a transition period between the use of forward prices and fundamental forecast data. The Commission expects to revisit this issue both in Duke's IRP proceeding and in the 2021 avoided cost proceeding.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, the Joint Initial Comments of SACE, NCCEBA, and NCSEA, and Duke Energy's Reply Comments.

#### SUMMARY OF THE EVIDENCE

The Commission's Sub 158 Order determined that renewable generation is capable of providing fuel price hedging benefits, and, therefore, required DEC and DEP to recalculate their avoided energy rates to include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation. In its Initial Statement, Duke Energy states that it had updated its avoided energy cost rate calculations to include the same hedge value approved for Dominion Energy North Carolina in their Sub 158 avoided cost rates, and that for purposes of this streamlined 2020 standard offer avoided cost rate proceeding, Duke Energy has developed its avoided energy rates to incorporate the same avoided fuel hedge value recently accepted in the Sub 158 proceeding.

In their Joint Initial Comments, SACE, NCCEBA, and NCSEA state that although use of the Black-Scholes Model to determine the fuel hedging value provided by qualifying facilities that use renewable energy meets the minimum requirements of the Commission's

order, a more accurate methodology would better comply with the Sub 158 Order's requirement for an appropriate fuel hedging value and with the underlying statute. SACE, NCCEBA, and NCSEA state that the Black-Scholes Model undervalues the long-term physical hedge against natural gas price volatility provided by a long-term fixed-price PPA with a renewable QF and that the Black-Scholes Model does not accurately represent the added fuel price stability gained through each year in a long-term fixed-price PPA with a renewable QF. As a result, SACE, NCCEBA, and NCSEA recommend that the Commission direct Duke to investigate and apply a more accurate model that better conforms to the Commission's prior order.

In its Reply Comments, Duke Energy states that their use of the Black-Scholes model in this proceeding should not be considered a compliance issue and instead should be considered in a future avoided cost proceeding.

#### DISCUSSION AND CONCLUSIONS

The Sub 158 Order required Duke to "include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation...." Although Duke has used the Black-Scholes Model to calculate the hedging value of renewables, the Commission agrees with SACE, NCCEBA, and NCSEA that the Black-Scholes Model undervalues the long-term physical hedge against natural gas price volatility provided by a long-term fixed-price PPA with a renewable QF and that the Black-Scholes Model does not accurately represent the added fuel price stability gained through each year in a long-term fixed-price PPA with a renewable QF. Therefore, the Commission will accept Duke's use of the Black-Scholes Model for the purposes of this proceeding, but Duke will be required in the 2021 avoided cost proceeding

to include in its initial filings a consideration of alternative fuel hedging methodologies, including those discussed in the Crossborder Energy Report on behalf of the SACE, NCCEBA, and NCSEA.

#### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 29-32**

The evidence supporting these Findings of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, and Duke Energy's Reply Comments.

#### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that its Schedule PP rates, as approved in the Sub 158 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 Sub 158 proceeding, Duke Energy undertook a line loss study. Duke Energy determined that it was appropriate for DEC and DEP to continue offering a line loss adder because their studies showed that the number of substations on their respective systems where backflow was reducing or negating the avoided line loss benefits of distribution-connected QFs was not substantial enough to eliminate the line loss adder for relatively small 1 MW or less standard offer QFs. The Commission approved Duke Energy's determination and further concluded that it was appropriate for Duke Energy 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 next biennial avoided cost proceeding. The Commission also found that Duke Energy proposal to assess the individual characteristics of QFs that are not eligible for Schedule PP standard offer rates and to address the line loss adder analysis as part of the PPA negotiation process was consistent with N.C. Gen. § 62-156(c)

by taking into consideration the individual characteristics of the QF.

Duke Energy states that it analyzed the levels of connected, under construction, and queued QF solar generating facilities interconnected to the DEC and DEP distribution systems to determine the number of substations that currently are or are expected to experience backfeed in the near future. Currently, in DEP, 100 out of 408 substation banks, or 24.5%, are backfeeding into the transmission system due to distribution-connected generation. Duke Energy's analysis further indicates that despite the high number of queued projects requesting to interconnect to the DEP distribution system in the near future, only about 132 out of 408 substations, or 32% of DEP's substations, are estimated to experience backfeed before the projects being addressed by this avoided cost proceeding start connecting. This relatively low percentage is in part due to the concentrated nature of QF solar development in more rural areas of the DEP eastern North Carolina service territory.

For DEC, the percentages of substation banks currently experiencing backfeed due to distribution-connected projects is significantly less—only 4.2%. Even accounting for the estimated impact of queued projects requesting to interconnect to the DEC distribution system, this number only increases to 7.7%. This is due to DEC having less than half the amount of connected, under construction, and queued distributed generation projects within its service territory than DEP and, additionally, DEC having a greater number of substations than DEP (1041 total substation banks analyzed).

Based upon this analysis, Duke Energy determines that it is appropriate to retain a line loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP at this time. For the 100 MW of aggregate standard offer QF generation

seeking to interconnect to Duke Energy's distribution systems, the potential for avoided line loss benefits from this Schedule PP-eligible QF generation remains on most substations within both the DEP and DEC service territories. However, for proposed distribution-connected QFs that are not eligible for Schedule PP, and in accordance with the Sub 158 Order, Duke Energy plans to continue considering whether the QF's energy output would backfeed the substation and inject energy onto the transmission system. Consistent with HB 589, Duke Energy will 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.

Duke Energy also states that it will work with the Public Staff to more precisely define the issues around avoided transmission and distribution capacity benefits and advise the Commission on the Companies' determinations in the next biennial avoided cost proceeding.

In its Initial Statement, the Public Staff states that it reviewed the information filed by Duke Energy related to line loss adders and back-feeding of substations, and agrees with its proposals. The Public Staff states that it will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings, and recommends that the Commission direct the utilities to continue to file information to support the removal/inclusion of the line loss adder in their proposed avoided cost rates in future avoided cost proceedings. It further recommends that Duke Energy evaluate and report on any geographical concentrations of back-feeding substations and whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate.

In its Reply Comments, Duke Energy agrees with the Public Staff's

recommendation and committed to discuss this issue with the Public Staff prior to Duke Energy's November 2021 filing. Duke Energy requests the Commission approve its currently proposed distribution line loss adder included in the standard offer Schedule PP rates for purposes of this proceeding.

### DISCUSSION AND CONCLUSIONS

The Commission finds it appropriate for Duke Energy to retain a line-loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP at this time. The number and percentage of substations that are experiencing backfeeding remains low. The Commission recognizes the agreement between Duke Energy and the Public Staff to discuss the issue before Duke Energy's filing in the 2021 proceeding, and anticipates Duke Energy filing updated information.

### **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 33**

The evidence supporting this Finding of Fact is found in Duke Energy's Request for Continuance and its Initial Statement.

### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy incorporated solar integration services costs ("SISC")<sup>3</sup> into its avoided energy rates in the same manner as approved in the Sub 158 Order and did not propose any modifications to the integration cost amounts or to the rate design approved in the Sub 158 Order. Duke Energy stated that it is evaluating the issue with the Public Staff and other interested stakeholders and is undertaking the formation of

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<sup>3</sup> In the Sub 158 proceeding, Duke argued that it was not seeking to assess a charge on QFs for solar integration costs but was instead including such costs as a reduction to its avoided cost rates. The Commission agreed with this characterization and rejected the argument of SACE, NCCEBA, and NCSEA that Duke was proposing to establish a new charge that required a ratemaking proceeding. Despite these facts, Duke and other parties have continued to make reference to a solar integration "*charge*." This inaccurate nomenclature should not be perpetuated.

the independent technical review committee, as directed in the Sub 158 Order, to review the Astrapé Study methodology and the model used for system simulations.

### DISCUSSION AND CONCLUSIONS

In the Commission's October 30, 2020 Order Granting Continuance and Establishing Reporting Requirements in this proceeding, the Commission expressed disappointment with Duke Energy's failure to address the Sub 158 Additional Issues in the timeframe prescribed in the Sub 158 Order, including the independent technical review of the Astrapé Study solar integration services cost (SISC) methodology, but allowed Duke to present the results of the technical review in the 2021 avoided cost proceeding. The Commission stated its expectation that Duke would provide "thoughtful, justified, and robust responses" to the Sub 158 Additional Issues, including the SISC methodology review. The Commission further stated that it expects Duke to:

[M]ake significant effort to address all of the Sub 158 Additional Issues, resolving these issues or otherwise achieving consensus with interested stakeholders before the commencement of the next biennial avoided cost proceeding. Specifically, with respect to the independent technical review of the Astrapé Study solar SISC methodology, the Commission accepts Duke's commitment to transparency, to providing an update once the technical review committee is selected, and to scheduling a stakeholder meeting in Summer 2021 to discuss the report of the technical review committee and results from the technical review committee's work. Additionally, the Commission expects and encourages the Movants and interested parties to use this additional time to reach consensus to the maximum extent possible on all of the issues to be presented to the Commission in the November 1, 2021 filing.

The Commission reiterates that expectation here and strongly encourages Duke to work with interested parties to reach consensus to the maximum extent possible on this issue prior to the November 1, 2021 filing.



## **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement.

### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it continues to evaluate potential real-time pricing or other tariffs that could provide more granular rate structures and price signals to QFs for the benefit of customers and plan to further evaluate this issue under the recent revisions to FERC's implementing regulations established in FERC Order No. 872. Duke Energy states it will make any recommendations to the Commission on this issue in its next biennial avoided cost filing.

### DISCUSSION AND CONCLUSIONS

The Commission recognizes Duke Energy's commitment, pursuant to direction in the Sub 158 Order, to provide its evaluation and recommendations concerning real-time pricing or other tariffs that could provide more granular rate structures and price signals to QFs.

## **EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 35-39**

The evidence supporting these Findings of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, the Joint Initial Comments of SACE, NCCEBA, and NCSEA, Duke Energy's Reply Comments and the Public Staff's Reply Comments.

### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it is continuing to use the Commission-approved avoided energy and capacity rate designs outlined in the Sub 158

Rate Design Stipulation. As approved in the Sub 158 Order, the Schedule PP capacity rate design offers three distinct pricing periods to most accurately reflect the marginal capacity value to customers during each period. The pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the winter months of December, January, February, and March. No capacity payments apply during the remaining months. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. The seasonal months and three capacity pricing periods are the same for DEC and DEP.

Duke Energy amended its Schedule PP tariffs to reflect the updated avoided cost rates. Duke Energy also made limited modifications to its Schedule PP PPAs and Terms and Conditions approved in the Sub 158 Order, including to reflect the Companies' plans to make an updated avoided cost/standard offer filing in November 2021.

In addition, Duke Energy made limited revisions to its standard offer PPA forms. First, Duke Energy deleted the limiting reference to hydro generating facilities in the recitals to reflect that HB 589 expanded the definition of small power producer in N.C. Gen. Stat. § 62-3(27a) to include all types of small power producer QFs under PURPA. Second, Duke Energy amended Section 6 to provide that the Companies may require standard offer Sellers above 100 kW to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. In response to the Public Staff, Duke Energy subsequently agreed to delete this provision, as discussed below. Finally, Duke Energy updated the Appendix A energy storage protocols applicable to standard offer solar QFs integrating battery storage to incorporate certain changes to the existing storage protocols consistent with the protocols most recently utilized in the CPRE

Tranche 2 RFP.

Relatedly, Duke Energy proposes limited ministerial changes to the Schedule PP standard offer Notice of Commitment form to state that QFs submitting the Notice of Commitment form after the filing of these updated rate schedules shall be eligible for the new avoided cost rates filed in this docket, as well as to make clear that the “Effective Date” of the Notice of Commitment form and establishment of a LEO thereunder will be used for purposes of determining the priority of QFs for eligibility for Schedule PP under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW).

In its Initial Statement, the Public Staff expresses concern about Duke Energy’s proposal to reduce the threshold from three MW to 100 kW for requiring QFs to provide prior notice of annual, monthly, and day-ahead forecasted hourly production, as specified by the respective utility, as discussed below.

The Public Staff also expresses concern about the way the Duke treated start-up costs in the production cost model that is used to determine avoided energy costs and the counterintuitive effect this had on winter peak rates. In its Initial Statement, the Public Staff identifies that the avoided energy rates filed by DEC and DEP exhibited counterintuitive behavior in some schedules. For example, the variable rate for both DEP and DEC, and the 10 year fixed rate for DEP, all have a winter AM-peak rate that is actually lower than the winter off-peak rate; and the 10 year fixed rate for DEC has a shoulder on-peak rate that is lower than the shoulder off-peak rate. The Public Staff was concerned that this behavior was not reflective of actual avoided costs, and might in fact be an artifact of the production cost modeling; in that case, the time variant rates would not incentivize the appropriate operational behavior from dispatchable QFs.

The Public Staff determined that the primary driver for these counterintuitive rates was due to a change in the way the Duke has treated start-up costs in the production cost model that is used to determine avoided energy costs. Start-up costs for certain units, particularly coal units, can be very expensive. Prior to these proceedings, these start costs would be converted to a \$ per MWh rate, based on how long the unit was run after it was start up. Sometime in 2019, Duke changed its methodology, and start costs are now allocated entirely to the hour in which they occurred. According to Duke, this likely explains the very low rates for winter AM-peak rates, which is the shortest rate period (only one hour preceding and one hour following the winter premium peak period).

Duke Energy notified the Public Staff that it intended to re-run its production cost models using the Sub 158 methodology of spreading the start costs over each unit's run time. The Public Staff believed that doing so would resolve the problem, and anticipated Duke would file a revised rate schedule incorporating the change. The Public Staff also anticipates working with Duke on the issue prior to the November 2021 avoided cost filing.

In their Joint Initial Comments, SACE, NCCEBA, and NCSEA identify the same issue as the Public Staff, pointing out that in the near term, Duke's proposed avoided energy costs for the winter morning peak period are unreasonably low—much lower, in fact, than the avoided energy prices for surrounding off-peak hours. This is particularly true in near-term years and does not make sense for a peak period and is apparently due to old production cost modeling techniques. SACE, NCCEBA, and NCSEA recommend that the avoided energy costs for this period should be averaged, for at least the first few years, with the avoided energy costs in the other winter peak and premium peak periods, so that accurate price signals are sent to QFs.

In its Reply Comments, Duke Energy states that on February 12, 2021, it made a filing entitled Supplemental Filing of Revised Energy Rate Calculations and Updated Avoided Energy Rates, in response to concern expressed in the Public Staff's Initial Comments and SACE, NCCEBA, and NCSEA's Joint Initial Comments that Duke Energy's initially proposed avoided energy costs resulted in counterintuitive energy pricing periods, which included on-peak rates being lower than off-peak rates in certain periods. Duke Energy states that this was due to a change in the way that its production cost modeling treated unit start costs, as compared to the Sub 158 proceeding. Duke Energy states that it reverted to modeling unit start costs in the same manner as was done in the Sub 158 proceeding, and will discuss the issue further with the Public Staff and address any resulting rate design changes in the upcoming 2021 filing.

In its Reply Comments, the Public Staff acknowledge Duke Energy's February 12, 2021 supplemental filing and explained that Duke Energy re-ran its production cost models spreading the start costs over each unit's run time, which was consistent with the approach used in the Sub 158 Proceeding. The Public Staff state that it reviewed the revised filings and finds that the revisions appear to resolve the anomalies previously identified, and believes that the revised rates are appropriate for use in this proceeding. It agrees to continue to discuss the treatment of start costs in production cost modeling with Duke and other parties for further consideration in the November 2021 filing.

#### DISCUSSION AND CONCLUSIONS

The Commission finds it reasonable and appropriate for Duke Energy to continue to use the avoided energy and capacity rate designs outlined in the Sub 158 Rate Design Stipulation for Schedule PP. The modifications to Schedule PP tariffs, reflecting updated

avoided cost rates, are reasonable and appropriate. The limited modifications to Schedule PP PPAs and Terms and Conditions, as approved in the Sub 158 Order, are reasonable and appropriate. The limited revisions to Duke Energy's standard offer PPA forms are reasonable and appropriate. Duke Energy's limited ministerial changes to the Schedule PP standard offer Notice of Commitment form, to state that QFs submitting the Notice of Commitment form after the filing of updated rate schedules shall be eligible for the new avoided cost rates filed in this docket, and to make clear that the effective date of the Notice of Commitment form and establishment of a LEO thereunder will be used for purposes of determining the priority of QFs for eligibility for Schedule PP under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW), are reasonable and appropriate.

Finally, the Commission recognizes the consensus among the parties that Duke Energy's initially filed winter on-peak energy prices were erroneous as a result of a modeling error, and that Duke Energy attempted to correct the error and filed revised rates in a supplemental filing February 12, 2021. In light of the Public Staff's finding that Duke Energy's revision corrected the error and the absence of any objection from any other party, the Commission finds Duke Energy's revised rates reasonable and appropriate.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, Duke Energy's Reply Comments and the Joint Reply Comments of SACE, NCCEBA, and NCSEA.

#### **SUMMARY OF THE EVIDENCE**

In its Initial Statement, Duke Energy reviews its revisions to its standard offer PPA forms. First, Duke Energy deleted the limiting reference to hydro generating facilities in

the recitals to reflect that HB 589 expanded the definition of small power producer in N.C. Gen. Stat. § 62-3(27a) to include all types of small power producer QF under PURPA. Second, it amended Section 6 to provide that the Companies may require standard offer Sellers above 100 kW to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. Duke Energy states that it had no present intent to require such information from small standard offer QFs. However, it believed this change was appropriate to better align this provision with revised standard offer eligibility under HB 589 and to recognize that it may become appropriate in the future to request operational data from smaller QFs during the terms of these PPAs as increasing penetrations of distributed energy resources are installed on Duke Energy's systems. Finally, Duke Energy updated the Appendix A energy storage protocols applicable to standard offer solar QFs integrating battery storage to incorporate certain changes to the existing storage protocols consistent with the protocols most recently utilized in the CPRE Tranche 2 RFP.

In its Initial Statement, the Public Staff notes that these reporting requirements were last addressed by the Commission in the Sub 140 Phase 1 Order, in which DEC and DEP proposed a similar 100 kW threshold for requiring forecasted hourly production rates from QFs. In that proceeding, DEC, DEP, and the Public Staff ultimately agreed to alternative language limiting the reporting requirements to facilities larger than three MW. DEC and DEP note in their Joint Reply Comments that the forecast information would aid them in procuring alternative resources when a QF plans reduced operations, but acknowledged that a request for planned operational information is unlikely to be necessary for QFs below three MW based upon current system operations. The Commission in its Sub 140 Phase 1

Order found that the three MW threshold agreed to by DEC, DEP, and the Public Staff should allow DEC and DEP to plan system operations without being unduly onerous to the QFs.

The Public Staff state that it recognizes the value of accurate production data for system operations and has concerns that lowering the reporting threshold from three MW to 100 kW may be onerous and costly for some small QFs. In addition, the Public Staff question whether it is likely now or in the foreseeable future for the utilities to rely on the production forecasting information from small QFs for procuring alternative resources. The Public Staff further note that DEC and DEP indicated in response to Public Staff data requests that they have not requested operational forecasts information from any QFs less than five MW in the past five years.

The Public Staff also acknowledge Duke's goal to align this provision with revised standard contract eligibility established under HB 589, but note that since neither DEC or DEP have entered into purchase contracts in the aggregate capacity of 100 MW or more with facilities that established legally enforceable obligations after November 1, 2016, the current threshold remains at 1 MW for standard offer contract eligibility pursuant to N.C.G.S § 62-156(b)(1). The Public Staff find that a facility greater than 1 MW may be better situated to agree to certain production forecasting reporting requirements as part of a negotiated contract process with DEC or DEP, and therefore recommended that the Commission direct DEC and DEP to revise their standard offer contracts to require the forecasted hourly production rates from QFs only from facilities greater than 1 MW in capacity.

In its Reply Comments, Duke Energy state that the purpose of the change was solely



to have the optionality to request this information from smaller QFs if necessary based upon future system conditions and operational needs. Duke Energy agree that, in the interest of resolving this issue, it will revise this standard offer PPA to delete this provision and to prospectively limit the production forecast reporting requirements to QFs greater than one MW entering into negotiated PPAs.

In their Joint Reply Comments, SACE, NCCEBA, and NCSEA agree with the Public Staff that lowering the threshold for requiring prior notice of annual, monthly, and day-ahead forecasted hourly production from 3 MW to 100 kW would be onerous and costly for some small QFs, and likely unnecessary because Duke is unlikely to rely on forecasts from small QFs. The groups support the Public Staff's proposal to lower the threshold to 1 MW as a reasonable compromise.

#### DISCUSSION AND CONCLUSIONS

The Commission will accept Duke Energy's proposal, initially suggested by the Public Staff and supported by joint intervenors SACE, NCCEBA, and NCSEA, to revise its standard offer PPA to delete the provision in question, and to prospectively limit the production forecast reporting requirements to QFs greater than 1 MW entering into negotiated PPAs. The Commission notes that Duke Energy has not made significant use of this reporting in the past and has not stated any plans to do so in the future. In addition, Duke Energy does not allege that the information is needed for forecasting and does not disagree that the reporting requirement would be onerous for small facilities.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, Joint Initial Comments of SACE,

NCCEBA, and NCSEA, Duke Energy’s Reply Comments, and the Joint Reply Comments of SACE, NCCEBA, and NCSEA.

#### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it is continuing to use the Commission-approved avoided energy and capacity rate designs outlined in the Sub 158 Rate Design Stipulation. As approved in the Sub 158 Order, the Schedule PP capacity rate design offers three distinct pricing periods to most accurately reflect the marginal capacity value to customers during each period.

In its Initial Statement, the Public Staff raises concerns with the natural gas price forecasts used by Duke Energy in its IRP. The Public Staff notes that Duke Energy properly included transportation cost estimates for the required interstate and intrastate capacity for the delivery of the shale gas, as it did in the 2018 filing. However, in prior IRP proceedings, Duke was relying on the Atlantic Coast pipeline (“ACP”) to transport natural gas into North Carolina. The ACP was a 600-mile, 42-inch natural gas interstate pipeline that would have transported approximately 1.5 billion cubic feet (Bcf) per day of Appalachian gas on a firm transportation basis to the Zone 5 region. DEC and DEP, along with Piedmont Natural Gas, had contracted for about 48% of its capacity or roughly about 725,000 dekatherms (dts) per day. The cancellation of the ACP in July 2020 has brought Duke’s assumptions of having additional increased interstate pipeline capacity from the Appalachian basin by 2026 into question, especially given the political and economic issues surrounding the construction of new natural gas pipelines.

Another interstate pipeline project currently under construction is the 303 mile, two-Bcf/day Mountain Valley Pipeline (“MVP”) mainline project, which is designed to

flow large volumes of firm transportation volumes at the lower cost gas cost out of the Appalachian region and into the markets of Virginia and North Carolina is now delayed and scheduled to enter service in late 2022. The MVP also faces additional legal challenges, calling into question the future of this pipeline. MVP Southgate, an offshoot to MVP, a 24-inch interstate pipe running approximately 75 miles from Southern Virginia to central North Carolina and carrying 375,000 dts/day of shale gas cannot start construction until the MVP mainline project has all federal permits approved.

Currently, the growth of natural gas production in the Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast markets.

The Public Staff raises the concern that Duke Energy's capacity expansion models will too greatly rely on natural gas. It recommends that Duke in its 2021 avoided cost filing re-evaluate its assumptions regarding the availability of additional interstate pipeline capacity, and that if Duke continues to assert that adequate capacity will be available, it should provide the Commission and stakeholders with a detailed narrative that identifies expected actions by various pipeline developers and other parties with expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential new interstate pipelines. Furthermore, the Public Staff recommends that Duke should also consider developing an IRP portfolio or sensitivity in the 2021 IRP Update that is similar to their base case but which includes natural gas import restrictions or less reliance on certain gas.

In their Joint Initial Comments, SACE, NCCEBA, and NCSEA also identify a similar concern with Duke Energy's gas transport assumptions. SACE, NCCEBA, and

NCSEA explain that as part of Duke Energy’s natural gas forecast, Duke Energy applied the basis differentials between the Henry Hub Zones 4 and 5 on the Transco pipeline, where its gas-fired power plants are located. The “basis differential” is simply the difference between (1) market prices in a reference market (for natural gas, this is the Henry Hub in Louisiana where the major gas forward market is located) and (2) market prices at a different location on the gas system (e.g. market prices in the Transco Zones 4 and 5 in North Carolina). The basis can be positive or negative relative to the Henry Hub. Generally, the basis is (2) minus (1), so for example, if Transco Zone 5 prices are higher than the Henry Hub, the basis for Transco Zone 5 is positive. SACE, NCCEBA, and NCSEA are concerned that the Henry Hub basis differentials beginning in 2026 were based on the existence of a new natural gas pipeline that does not currently exist and is not currently planned, and recommend that Duke should be required to continue using its existing Henry Hub differentials.

In its Reply Comments, Duke Energy respond to the Public Staff’s concern relating to Duke Energy’s reliance upon forecasted lower cost natural gas pricing utilizing the Appalachian basin’s lower cost Dominion South (“DS”) Point hub starting in year 2026, as opposed to continued utilization of the Transco Zones 4 and 5 pricing through and past year 2026, on the basis of the current lack of operating gas pipeline infrastructure near the DS Point hub due to the recent cancellation of the Atlantic Coast Pipeline, as well as the uncertain future regulatory landscape for the construction of new gas pipelines, specifically the Mountain Valley Pipeline (“MVP”), in this region. However, Duke Energy notes that the Public Staff accepted the DS trading hub price assumption as reasonable for this proceeding.

Duke Energy argue that its forecasting assumptions, including longer-term reliance on lower-cost gas at the DS trading hub, are reasonable and should be used, because they align with the Companies' 2020 IRP base planning assumptions. However, Duke Energy also agree with the Public Staff's recommendation that Duke Energy further evaluate its assumptions regarding the availability of additional interstate pipeline capacity, and to provide the Commission and stakeholders with updated information on expected actions by various pipeline developers and other parties and to address expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential pipelines. Duke Energy commits to provide updated information on this topic to the Commission in either its reply comments in the current 2020 IRP proceeding and/or in the 2021 IRP update and avoided cost filings, as appropriate, and argue that this is first and foremost an IRP issue that will then influence subsequent valuations of avoided costs.

Duke Energy also respond to the Public Staff's recommendation that it consider developing an IRP portfolio or sensitivity in the 2021 IRP Update that is similar to their base case but which includes natural gas import restrictions or less reliance on DS trading hub gas. Duke Energy generally accept the Public Staff's recommendation to consider developing an IRP portfolio or sensitivity in their future IRPs that is similar to their base case but which includes natural gas import restrictions or less reliance on DS trading hub gas. However, it believed the next comprehensive IRP filing in 2022 is more appropriate for developing this type of sensitivity analysis.

Duke Energy also respond to SACE, NCCEBA, and NCSEA's contentions that Duke Energy did not comply with the Sub 158 Order, that it was not reasonable or

appropriate for Duke to change several of the combined-cycle plants to the Dominion South zone beginning in 2026, their request that the Commission require Duke Energy to use the Transco Zones 4 and 5 for the entire applicable forecast period, and their contention that Duke Energy's updated differential basis does not appear to incorporate capacity reservation costs, which must be considered when determining the economics of a prospective new pipeline.

Duke Energy argued that it did comply with the Sub 158 Order because it adhered to the Commission's directive in the 2020 Procedural Order to update the inputs to their avoided cost rates based upon the methodological guidelines and requirements approved in the Sub 158 Order, and generally relied upon the natural gas forecasting transportation assumptions presented in DEC's and DEP's 2020 IRPs. Duke Energy also disagrees that MVP will not be constructed.

Duke Energy states that the longer-term natural gas transportation assumptions for providing natural gas to its combined cycle fleets and potential future CTs may not have a major impact on avoided cost rates because Duke Energy assumed that the DS hub would be operational only in 2026, and because the impact of this lower priced gas will occur when Duke Energy's natural gas units, that receive gas from the DS hub, are the marginal resource, and avoided energy costs will be less than if the natural gas was sourced from Transco Zone 4 or 5.

Finally, Duke Energy argue that it is not accurate that capacity reservation costs must be considered when determining the economics of prospective new pipeline for purposes of calculating the Companies' avoided capacity costs under the peaker methodology because for CTs Duke Energy has consistently assumed #2 fuel oil as the

backup fuel source as opposed to relying upon firm gas capacity reservations.

In their Joint Reply Comments, SACE, NCCEBA, and NCSEA strongly agree with the Public Staff's reservations regarding Duke's assumed ability to transport large volumes of natural gas on a daily basis to its gas-fired units. They also agree with the Public Staff's recommendation that in its 2021 avoided-cost filing Duke should reevaluate its assumptions regarding the availability of additional interstate pipeline capacity, and that in its 2021 IRP update Duke should include a portfolio or sensitivity that includes import restrictions or less reliance on natural gas.

However, SACE, NCCEBA, and NCSEA do not agree with the Public Staff that Duke Energy's unfounded assumption of additional pipeline capacity could be substantiated by a detailed narrative that identifies expected actions by various pipeline developers and other parties with expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential new interstate pipelines. They point out that obstacles to constructing new pipelines, such as legal, regulatory, or other project development challenges, will persist regardless of Duke's expectations, and it is unclear why Duke is in a position to accurately predict expected actions related to pipeline capacity development. They also argue that relying on those predictions by Duke Energy would be contrary to the "known and verifiable" standard.

#### DISCUSSION AND CONCLUSIONS

The Commission will require Duke Energy to revise its natural gas transport assumptions and file updated rates. For reasons the Public Staff and joint intervenors SACE, NCCEBA, and NCSEA identified, these assumptions are based on outdated information. While it might be reasonable to base future natural gas price forecasts on the

in-service date for a pipeline that will be constructed, the ACP has been cancelled and although it has not been cancelled, the MVP is in legal jeopardy and faces a more difficult regulatory environment. There is no basis to assume that some equivalent pipeline will be constructed between now and 2026. Nor should Duke Energy maintain its assumptions about low natural gas transport costs on the basis of a narrative description of the activities of pipeline developers. Duke Energy is welcome to file that information but should not assume that a future pipeline will be constructed until its developer has received a certificate of public convenience and necessity and all required permits.

The Commission recognizes that Duke Energy views this primarily as an “IRP issue” with secondary impacts to avoided cost calculations, but the Commission does not see it that way. An error in the assumptions used to calculate avoided costs is an error in this proceeding and must be corrected here. Furthermore, the Commission recognizes Duke Energy’s argumentation concerning the magnitude of the error but is not persuaded that the error is so minor as to be overlooked. Accordingly, the Commission does not accept Duke Energy’s proposal to provide updated information on this topic to the Commission in either its reply comments in the current 2020 IRP proceeding and/or in the 2021 IRP update and avoided cost filings is sufficient. Because this has brought to light a potential flaw in Duke Energy’s IRPs, the Commission accepts Duke Energy’s proposal to develop an IRP portfolio or sensitivity in its IRPs that is similar to its base case but which includes natural gas import restrictions or less reliance on DS trading hub gas and will require this in Duke Energy’s current IRP filing.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42**

The evidence supporting this Finding of Fact is found in Duke Energy’s Initial



Statement, the Initial Statement of the Public Staff, Joint Initial Comments of SACE, NCCEBA, and NCSEA, Duke Energy's Reply Comments, and the Reply Comments of the Public Staff.

#### SUMMARY OF THE EVIDENCE

In its Initial Statement, Duke Energy states that it calculated its avoided energy rates by relying upon the methodology directed to be used in the Sub 158 Order, 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. Specifically, it relied upon forward market price data out eight years (2021-2028) as an indicator of the near-term future commodity costs of natural gas for purposes of calculating the Companies' avoided energy cost rates before transitioning to fundamental forecast data starting in year nine. Duke Energy notes its preference for the methodology it uses for its IRPs, rely upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived based upon fundamental forecasts over the remainder of the planning period. Duke states that it plans to discuss the issue with the Public Staff in the future and will have as its goals maintaining consistency with the Companies' IRPs in future biennial avoided cost proceedings and providing the most accurate forecasts achievable.

In its Initial Statement, the Public Staff states that it finds that Duke Energy incorporated forward basis natural gas prices for the first eight years, and for years nine and ten Duke has incorporated on its fundamental gas price forecast, and that the approach is consistent with the Commission Orders in Docket No. E-100, Subs 148 and 158. However, the Public Staff notes a number of concerns with the natural gas price forecasts that Duke Energy used in the IRP. These concerns primarily relate to transportation costs,

as discussed above.

In their Joint Initial Comments, SACE, NCCEBA, and NCSEA raise the concern that Duke Energy relied exclusively on fundamentals forecasts developed by private firms, omitting public data. Duke used fundamentals forecasts for Henry Hub prices from the private consultancies IHS and ICF. SACE, NCCEBA, and NCSEA recommend that these private forecasts should be supplemented with a public Henry Hub forecast, such as the Energy Information Administration's 2020 Annual Energy Outlook forecast of Henry Hub prices, citing the Commission's emphasis on transparency in its Sub 158 Order. SACE, NCCEBA, and NCSEA point out that the addition of a public Henry Hub forecast would serve as an appropriate check, would add transparency, and would provide the useful additional perspective and data of another prominent forecaster.

In its Reply Comments, Duke Energy argue that SACE, NCCEBA, and NCSEA's recommendation to use publicly available data should be rejected because it used the same forecasting methodology specifically approved in that Order and adhered to the Commission's directive in the 2020 Procedural Order to rely upon updated inputs consistent with the methodological guidelines approved in the Sub 158 Order.

In its Reply Comments, the Public Staff state that it found Duke Energy's long-term fundamental price forecast reasonably comparable to EIA's 2020 Annual Energy Outlook ("AEO") gas price forecast and no intervenors have provided persuasive evidence that the Utilities' fundamental forecasts are inappropriate, and accordingly it does not believe that the mandated use of publicly available forecasts is warranted at this time.

#### DISCUSSION AND CONCLUSIONS

The Commission reaffirms its commitment to ensuring transparency whenever

possible. As the Commission stated in its Sub 158 Order:

[T]here may be some circumstances where it is appropriate for the CT costs derived from generic publicly available estimates to be tailored based on internal data and actual construction experience. However, the Commission stresses that these adjustments must be clearly delineated and justified to ensure the Commission's effort in recent proceedings to increase the transparency in these CT cost inputs to the avoided capacity rate calculations is not lost. Further, when the Utilities use generic publicly available estimates, whether adjusted or not, the burden is on the utility to demonstrate that the estimates approximate the utility's actual costs, and procedures should be made available that allow not only parties but other interested persons to obtain access to the estimates and any adjustments made to the estimates, if applicable.

The transparency concern that the Commission expressed concerning CT costs is no less true of fuel costs. Accordingly, the Commission will require Duke Energy to supplement its fundamentals forecasts for Henry Hub prices with a public Henry Hub forecast, such as the Energy Information Administration's 2020 Annual Energy Outlook forecast of Henry Hub prices.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement, Joint Initial Comments of SACE, NCCEBA, and NCSEA, and Duke Energy's Reply Comments.

#### **SUMMARY OF THE EVIDENCE**

In its Initial Statement, Duke Energy state that for purposes of this streamlined avoided cost rate proceeding, it developed its avoided energy rates to incorporate the same avoided fuel hedge value recently accepted in the Sub 158 proceeding.

As noted above, in their initial comments SACE, NCCEBA, and NCSEA point out that the statute requires the avoided cost of energy to include both "the expected cost of fuel and other operating expenses" for alternative sources and, separately, "the expected

security of the supply of fuel for the utilities' alternative power sources." N.C. Gen. Stat. § 62-156(b)(2). The groups believe that the Commission properly implemented this directive when it required Duke Energy to account for the "added fuel price stability gained through each year" as a result of purchases from a renewable QF under a long-term PPA.

SACE, NCCEBA, and NCSEA argue that while use of the Black-Scholes Model to determine the fuel hedging value provided by qualifying facilities that use renewable energy meets the minimum requirements of the Commission's order and has been litigated in prior Commission proceedings, a more accurate methodology would better comply with the Sub 158 Order's requirement for an appropriate fuel hedging value and with the underlying statute.

Relying on their Crossborder Energy Report, SACE, NCCEBA, and NCSEA argue that the Black-Scholes Model undervalues the long-term physical hedge against natural gas price volatility provided by a long-term fixed-price PPA with a renewable QF because this type of PPA provides added fuel price stability over the full term of the contract, or 10 years, whereas the Black-Scholes Model simulates buying sequential options to purchase an 8-month supply of natural gas at a fixed price, over a 10-year period. Because the price of each successive option depends on the then-prevailing market price, the Black-Scholes Model updates the price of natural gas fuel 15 times over the course of the 10-year period. As a result, they argue that the Black-Scholes Model does not accurately represent the added fuel price stability gained through each year in a long-term fixed-price PPA with a renewable QF. SACE, NCCEBA, and NCSEA acknowledge that this could be a methodological issue rather than a compliance issue, and if so it would be appropriate to revisit the issue in the full proceeding beginning in November.

In its Reply Comments, Duke Energy argue that the Commission should reject SACE, NCCEBA, and NCSEA's recommendation. Duke Energy argue that its avoided hedge value used in this proceeding is a methodological issue outside the scope of this proceeding, and not a compliance issue. Duke Energy agrees that the fuel hedge issue should be addressed in the Companies' November 2021 avoided cost filing.

#### DISCUSSION AND CONCLUSIONS

As discussed above, the Commission continues to recognize that, as stated in its Sub 140 Phase 1 Order, "there are fuel price hedging benefits associated with solar generation" and therefore "[i]t is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation." Sub 140 Phase 1 Order, p. 42; *see also* Sub 158 Order, p.102. The Commission's determination of the avoided cost of energy to the utility must include "the expected costs of the additional or existing generating capacity which could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities' alternative power sources." N.C. Gen. Stat. § 62-156(b)(2). Pursuant to this requirement, in the Sub 158 Order the Commission directed Duke to "include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA." It specified that the method used must value "the added fuel price stability gained through each year of the entire term of the QF power purchase agreement." Sub 158 Order, p. 62.

The Commission recognizes that in previous avoided cost proceedings both Duke

Energy and Dominion have proposed a hedge value of 0.028 cents per kWh in accordance with a Memorandum of Understanding with the Public Staff filed on February 2, 2016. The Commission also recognizes that in the 2018 proceeding Duke Energy opposed including a hedge value, but subsequently updated its avoided cost rate calculations to include the same hedge value approved for Dominion Energy North Carolina in Sub 158 avoided cost rates. In its Sub 158 Order, the Commission accepted as reasonable and appropriate for that proceeding DENC's proposed hedging value of \$0.30/MWh, which it assumed constant for all years of the Schedule 19-FP contract. For this proceeding, Duke Energy developed its avoided energy rates to incorporate the same avoided fuel hedge value recently accepted in the Sub 158 proceeding. The Commission finds these rates reasonable and appropriate.

As noted above, the Commission finds that the method of calculating the fuel price hedging benefits associated with renewable generation is a methodological issue and under the Order Granting Continuance is outside the scope of this "streamlined" proceeding. However, in light of the concern with the Black-Scholes method raised by SACE, NCCEBA, and NCSE and discussed in the Crossborder Energy Report, the Commission will require Duke Energy to reevaluate the Black-Scholes method in its filing in the 2021 avoided cost proceeding and compare it to alternative methods of valuation.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 44**

The evidence supporting this Finding of Fact is found in Duke Energy's Initial Statement, Joint Initial Comments of SACE, NCCEBA, and NCSEA, and Duke Energy's Reply Comments.

#### **SUMMARY OF THE EVIDENCE**

Duke Energy developed its avoided capacity and energy costs using the component

or peaker methodology. As the Commission has recognized in prior avoided cost proceedings, the peaker method calculates avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour). Duke Energy used modeling and assumptions consistent with those used in its most recent 2020 biennial IRPs and/or utilized Commission-approved inputs and methodologies adopted in the Sub 158 proceeding, to streamline the issues before the Commission in fixing its standard avoided cost rates. Duke Energy requests that this approach not be viewed as precedential to how the Companies will address such issues in future proceedings.

Duke Energy developed its avoided capacity rates consistent with the methodology that it used in the Sub 158 proceeding and that the Commission approved in the Sub 158 Order as appropriately implementing N.C. Gen. Stat. § 62-156(b)(3). As identified in the its recently filed 2020 IRPs, DEC's next avoidable undesignated capacity need occurs in 2026, while DEP's next avoidable undesignated capacity need occurs in 2024. Compared to the standard offer avoided cost rates approved in the Sub 158 proceeding, DEC's first year of avoidable capacity need shifted forward from 2028 to 2026, while DEP's first year of avoidable capacity need shifted outward from 2020 to 2024.

Consistent with the Commission's directives in prior avoided cost proceedings, the Sub 158 Order concluded that the Utilities should use the installed cost of a CT unit derived from publicly available industry sources, such as the United States Energy Information Administration ("U.S. EIA"), tailored to adapt such information to the Carolinas for purposes of calculating their avoided capacity costs. The Sub 158 Order additionally directed that in the 2020 biennial avoided cost proceeding the Utilities should evaluate and

apply cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility.

Duke Energy calculated its avoided capacity cost based upon the U.S. EIA's published overnight cost of a CT unit, tailored to the extent needed to adapt such information to North Carolina. The CT overnight cost increased approximately 14% compared to the Companies' 2018 Sub 158 avoided cost filing (\$624/kW in 2018 filing versus \$713/kW in the 2020 filing) primarily due to a smaller economies of scale adjustment and a lower unit capacity rating.

In their Joint Initial Comments, SACE, NCCEBA, and NCSEA point out that capacity prices should be based on up-to-date assumptions about the model of combustion turbine that would be used as a peaking resource. They note that Duke Energy assumes that the model would be an F-class turbine, but DEC is currently constructing a combustion turbine and chose an advanced H-class model. Furthermore, advanced turbines have lower heat rates, i.e., are more fuel-efficient, and efficiency will become increasingly important over time as combustion turbines compete with clean-energy resources that have very low variable costs.

In its reply comments, Duke Energy states that although DEC is currently constructing an H-class CT at its Lincoln County site, the unit reflects a unique arrangement with Siemens Energy allowing Siemens to build and test its newest H-Class technology. Duke Energy states that DEC's customers realize a significant capital cost savings and will receive all of the H-Class unit's energy during a four-year testing period



while only paying a portion of the fuel costs. Duke Energy terms the project a demonstration project that is not reflective of the Companies' actual system CT conditions or indicative of future system CT conditions. Duke Energy further responds that it operates a total of 32 F-class units in either simple-cycle or combined-cycle mode in the Carolinas, as opposed to the one new H-class Lincoln #17 CT, and that its 2020 IRPs, as well as prior IRPs, also similarly and consistently reflect F-class CTs as the generic peaking resource addition. Finally, Duke Energy argues that a simple cycle F-class CT unit is appropriate under the peaker methodology as a proxy for pure capacity because a simple cycle F-frame peaking unit is typically the least expensive type of traditional resource that the Companies can construct to provide capacity for reliability purposes.

#### DISCUSSION AND CONCLUSIONS

Capacity prices should be based on up-to-date assumptions about the resource that otherwise would be built to serve the capacity need. The preponderance of F-class turbines among existing resources is not persuasive as to the type of turbine that Duke Energy will procure in the future. Duke Energy's decision to construct an H-class CT at its Lincoln County site indicates that it is pursuing newer and more efficient technology, albeit with higher up-front cost. Duke Energy states that it has negotiated a favorable arrangement with Siemens for that particular turbine and that those costs are not generalizable. However, the question is not whether the costs of that project are generalizable but whether Duke Energy will pursue H-class turbines in the future. Duke Energy does not state that it would not have pursued an H-class turbine under normal terms. Finally, Duke Energy's decision to use an F-class turbine as the generic peaking resource addition in its most recent IRP demonstrates only that Duke Energy continues to consider an F-class turbine a generic

resource for planning purposes, and not that Duke Energy actually would procure an F-class turbine on the margin to fill capacity need.

The Commission also is not persuaded by Duke Energy's statement in its Reply Comments suggesting that the only reason Duke Energy would pursue an H-class or other more advanced CT would be to "manage the intermittent output of must-take solar generators". Duke Energy's own corporate carbon reduction goals make it highly likely that significant additional intermittent resources will be added to Duke Energy's system in the future, and it is incumbent upon Duke Energy to manage its system to maximize flexibility and incorporate these resources. This will be the case regardless of whether such resources are owned by third parties or by Duke Energy itself.

For these reasons, the Commission finds that Duke Energy's choice of combustion turbine for capacity prices is outdated and Duke will be required to use the more accurate assumption of an advanced turbine model.

#### **EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45**

The evidence supporting this Finding of Fact is found in the Joint Initial Comments of SACE, NCCEBA, and NCSEA, and Duke Energy's Reply Comments.

#### **SUMMARY OF THE EVIDENCE**

In their Joint Initial Comments, SACE, NCCEBA, and NCSEA point out that Duke Energy's input assumptions for the production cost modeling used to determine avoided energy costs include the emission costs for certain air pollutants such as criteria air pollutants NO<sub>x</sub> and SO<sub>2</sub>, and that DENC's avoided cost modeling also includes as an input the forecasted costs for CO<sub>2</sub> emissions, but Duke Energy's production cost runs do not include CO<sub>2</sub> emissions costs over the 10-year forecast period. They note that Duke Energy

nonetheless has included a line item for carbon emissions allowance in its work papers. Specifically, in Duke Energy's Response to Public Staff Data Request 2-3, Duke Energy provided an excel document including "Per ton costs of emission allowances for NOx, SO2, mercury, and CO2" and also a tab for "Emissions Allowance" with a zero cost allowance for CO2 in Duke Energy's "Emissions Allowance Forecasts".

SACE, NCCEBA, and NCSEA also point out that Duke Energy has announced a corporate commitment to achieve a 50% reduction in carbon emissions by 2030 and to be carbon-neutral by 2050, and its 2020 IRPs reflect this carbon goal and include carbon prices in most of the modeling scenarios. The DEC and DEP 2020 IRPs include a base forecast for carbon emission costs that starts at \$5 per ton in 2025 and escalates at \$5 per ton per year thereafter; this forecast of carbon emission costs is used in many IRP scenarios. The IRP scenarios that would place DEC and DEP on trajectories to meet Duke Energy's long-term commitment to be carbon-neutral by 2050 include a non-zero price for carbon. The IRP recognizes that placing such an economic weight on carbon emissions is important to stimulate development of new zero-emitting load-following resources. Duke Energy has not explained how it could meet its long-term commitment to reduce carbon emissions without an assumption of increasing carbon emission costs over time.

SACE, NCCEBA, and NCSEA argue that given Duke Energy's IRPs' extensive use of this forecast of increasing CO2 emission costs, and Duke Energy's own recognition that an assumption of non-zero carbon emission costs is necessary to meet its long-term corporate commitment, the avoided energy cost modeling in this case should use the IRPs' Base scenario for carbon emission costs starting in 2025. In the alternative, SACE, NCCEBA, and NCSEA request that the Commission consider the inconsistency between

the Duke Energy IRP and avoided cost calculations in their treatment of CO2 costs, and to address the issue in the 2020 IRPs and the 2021 avoided cost proceeding.

In its Reply Comments, Duke Energy agrees with the Public Staff's position in its Initial Statement, with respect to DENC, concerning which CO2 costs should be included in avoided energy costs. Duke Energy states that it used its 2020 IRPs' least cost "Portfolio A Base without Carbon Policy" to calculate avoided energy rates. Duke Energy agrees with the Public Staff that CO2 costs should not be included because today, there is no known and verifiable legal or regulatory requirement setting a mandatory price on carbon emissions applicable to Duke Energy. Duke Energy further argues that to include a CO2 cost would violate prior Commission directives and FERC guidance.

In their Joint Reply Comments, SACE, NCCEBA, and NCSEA disagree with the Public Staff's position on CO2 costs and submit that it is appropriate for the Commission to reconsider the application of the "known and verifiable" standard with respect to carbon costs that it applied in the Sub 140 Phase 1 Order. They point out that the likelihood of a carbon price in the near term is substantially greater than at the time the Commission issued its Sub 140 Order, more than six years ago, either through expected federal regulation replacing the Affordable Clean Energy ("ACE") Rule, citing *Am. Lung Ass'n v. Env't'l Prot. Agency*, 985 F.3d 914, 935–36 (D.C. Cir. 2021), or state policy including participation in regional emissions coordination efforts. They further reemphasize that since the Sub 140 Phase 1 Order, Duke Energy itself has established carbon reduction goals. They argue that all of these factors result in a significantly higher likelihood that a cost of carbon will apply during the avoided cost forecast period than at the time of the Sub 140 Phase 1 Order.

When the Commission found it appropriate to exclude a cost of carbon from

avoided-cost calculations, it stated that it would be appropriate to revisit the issue if and when the costs become “known and verifiable.” Sub 140 Phase 1 Order, p. 44. SACE, NCCEBA, and NCSEA submit that the high likelihood of forthcoming carbon regulations warrants revisiting the question of including a cost of carbon and that it would be appropriate to do so more fully in the fall 2021 avoided cost proceeding.

#### DISCUSSION AND CONCLUSIONS

As noted above concerning DENC, the Commission has developed concerns about the application of the “known and verifiable” standard. The Commission did not intend the standard to foreclose consideration of impending costs simply because they could not be precisely tabulated nor because they were not yet manifest in the regulatory environment. The standard does not require the Commission to turn a blind eye to developments that affect avoided costs. Accordingly, the Commission is persuaded by the arguments of SACE, NCCEBA, and NCSEA and will require Duke Energy to recalculate its avoided costs to include the cost of carbon using the IRPs’ Base scenario for carbon emission costs starting in 2025. Furthermore, as noted, the Commission will revisit the “known and verifiable” standard in the 2021 avoided cost proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That, pursuant to the Commission’s Order Granting Continuance, DENC and Duke Energy were to update the inputs in their avoided cost energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Commission’s Sub 158 Order, and accordingly the Commission’s acceptance or approval in this Order of methodological determinations made by DENC and Duke Energy is limited

to this proceeding and will not be precedential for the 2021 proceeding;

2. That DENC's proposed 19-FP and 19-LMP proposed rate schedules are reasonable and appropriate and shall be implemented subject to the remainder of this order;

3. That DENC's PLEXOS modeling technique to develop Schedule 19-FP and further the modeling input assumptions therein are approved;

4. That DENC's using 18 months of forward market prices, 18 months of blended prices (blend of market and ICF prices), followed by ICF prices exclusively starting in month 37 of the forecast period is approved as a way to determine future commodity prices;

5. That DENC's the LMP method, the use of nodal techniques rather than the entirety of the DOM zone, and continued inclusion of the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy costs are approved;

6. That the revised hedge value of \$0.02/MWh that DENC proposed, \$0.00002/kWh, although it was calculated using the Black-Scholes option pricing method and updated Henry Hub gas pricing data, represents a very significant reduction from prior approved values and accordingly DENC shall clarify its calculation in a filing within 30 days of this Order;

7. That, in light of the very significant reduction in the updated hedge value and the concern with the Black-Scholes method raised by SACE, NCCEBA, and NCSEA and discussed in the Crossborder Energy Report, DENC shall reevaluate the Black-Scholes method in its filing in the 2021 avoided cost proceeding and compare it to alternative methods of valuation;

8. That DENC's proposed solar QF avoidance protocols for the solar re-dispatch charge, as modified by the suggestion of the Public Staff, as well as DENC's continued use of a \$0.78/MWh re-dispatch charge as approved in the Sub 158 Order for purposes of this filing under Schedule 19-FP, are approved;

9. That DENC shall monitor, at least annually, the forecasts and behavior of CSGs that are actually paired with ESDs and attempt to avoid the RDC, and shall include that information and an analysis of actual solar volatility of CSGs in DENC's service territory in its future biennial avoided cost filings, although this monitoring and reporting requirement shall not entail any additional administrative burden on CSGs;

10. That DENC was correct to calculate its proposed avoided energy rates using its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165 and shall proceed with those rates, including CO2 prices, and the Commission will revisit the "known and verifiable" standard in the 2021 avoided cost proceeding;

11. That the continuing absence of line loss adder for DENC is approved; however, DENC shall file its reexamination of the appropriateness of a line loss adder with the Commission with its initial filing for the 2021 Avoided Cost Proceeding, shall ensure that all potential benefits of distributed solar are being adequately reflected in the filing, and shall provide transparency to review the line loss adder decision;

12. That the peaker method used by DENC is approved;

13. That DENC's continued use of the metric EA and its continued use of a PAF of 1.07 are approved;

14. That DENC's revised standard contracts and terms and conditions are approved, including conditions to include Exhibit G an Energy Storage Device Addendum,

Article 7 of DENC's standard offer contract, and DENC's definition of "material alteration";

15. That, following the supplemental filing made by Duke Energy, Schedule PP and the underlying Duke Energy rate design are approved;

16. That the use of peaker methodology is approved for this proceeding but will be reevaluated in the 2021 avoided cost proceeding;

17. That Duke Energy's modeling and assumptions, consistent with those used in its most recent 2020 biennial IRP proceeding, are approved;

18. That Duke Energy's determination that DEC's first need to be avoided is in 2026 and DEP's first need to be avoided is in 2024 is approved, although the Commission reaffirms that the need for new capacity may not be the only reason to procure new renewable resources, particularly when those resources operate at nearly zero marginal cost and can save money for customers;

19. That Duke Energy's continued calculation of avoided capacity costs using the peaker method is approved but will be examined again in the 2021 proceeding, wherein Duke shall provide scenarios that match realistic generation planning scenarios;

20. That Duke Energy's avoided capacity rates, which were developed with the methodology approved by the Commission in the Sub 158 proceeding, are approved;

21. That Duke Energy's proposal that QFs fueled by swine waste, poultry waste, and hydro power, receive capacity payments calculated regardless of the Duke Energy's demonstrated need for future capacity reflected in their IRPs is approved;

22. That Duke Energy's proposal stating that Duke Energy did not include avoided cost rates for hydro small power producers in excess of 1 MW in their standard



offer; but committing to complying with N.C. Gen. Stat. § 62-156(b)(3) with respect to negotiated PPAs with eligible hydro QFs greater than 1 MW but equal to or less than 5 MW is approved, and the Commission directs Duke Energy to comply and show proof of compliance in the next avoided cost application in 2021;

23. That Duke Energy's avoided CT Unit Capital Costs are approved;

24. That Duke Energy's use of the same EA metric approved in the Sub 158 Order to develop a PAF capacity multiplier, and the updated PAF finding of 1.06, are approved;

25. That Duke Energy shall address the appropriateness of using the EUOR metric in the 2021 avoided cost proceeding;

26. That Duke Energy's use of a 2.0 PAF in DEC's and DEP's standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW is approved;

27. That Duke Energy's continued reliance on the PROSYM generation production cost modeling platform to derive its system marginal energy costs is approved;

28. That Duke Energy's use of "no more than eight years" of forward natural gas prices before using fundamental forecast data for the remainder of the planning period is approved; however, the Commission expects to revisit this issue both in Duke's IRP proceeding and in the 2021 avoided cost proceeding;

29. That Duke's use of the Black-Scholes Model is approved, but Duke will be required in the 2021 avoided cost proceeding to include in its initial filings a consideration of alternative fuel hedging methodologies, including those discussed in the Crossborder Energy Report on behalf of the SACE, NCCEBA, and NCSEA;

30. That Duke Energy's retention of a line-loss adder for distribution-connected

standard offer-eligible QFs contracting under Schedule PP is approved;

31. That Duke Energy's unmodified SISC is approved;

32. That Duke Energy shall work with interested parties to reach consensus to the maximum extent possible on outstanding issues regarding the SISC prior to the November 1, 2021 filing;

33. That Duke Energy shall provide its evaluation and recommendations concerning real-time pricing or other tariffs that could provide more granular rate structures and price signals to QFs in its initial filing in the 2021 avoided cost proceeding;

34. That Duke Energy's continued use of the avoided energy and capacity rate designs outlined in the Sub 158 Rate Design Stipulation for Schedule PP is approved, subject to revisions required under this Order;

35. That Duke Energy's modifications to Schedule PP tariffs, reflecting updated avoided cost rates, are approved;

36. That Duke Energy's limited modifications to Schedule PP PPAs and Terms and Conditions, as approved in the Sub 158 Order, are approved;

37. That Duke Energy's limited revisions to its standard offer PPA forms are approved;

38. That Duke Energy's limited ministerial changes to the Schedule PP standard offer Notice of Commitment form are approved;

39. That, following Duke Energy's supplemental filing February 12 containing revised rates correcting an error, Duke Energy's revised rates are approved;

40. That Duke Energy's proposal to revise Section 6 of its standard offer PPA to delete a provision that would have required standard offer sellers above 100 kW to

provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by Duke Energy, and to prospectively limit the production forecast reporting requirements to QFs greater than 1 MW entering into negotiated PPAs, is approved;

41. That Duke Energy shall revise its natural gas transport assumptions and file updated rates, which shall not be based on an assumption that a future pipeline will be constructed until its developer has received a certificate of public convenience and necessity and all required permits;

42. That Duke Energy's shall develop an IRP portfolio or sensitivity in its IRPs that is similar to its base case but which includes natural gas import restrictions or less reliance on DS trading hub gas, and shall file this in Duke Energy's current IRP filing;

43. That Duke Energy shall supplement its fundamentals forecasts for Henry Hub prices with a public Henry Hub forecast, such as the Energy Information Administration's 2020 Annual Energy Outlook forecast of Henry Hub prices;

44. That Duke Energy's avoided energy rates, which incorporate the same avoided fuel hedge value recently accepted in the Sub 158 proceeding, are approved;

45. That Duke Energy shall reevaluate the Black-Scholes method in its filing in the 2021 avoided cost proceeding and compare it to alternative methods of valuation;

46. That Duke will be required to use the more accurate assumption of an advanced turbine model to determine capacity prices; and

47. That Duke Energy shall recalculate its avoided costs to include the cost of carbon using the IRPs' Base scenario for carbon emission costs starting in 2025, and the Commission will revisit the "known and verifiable" standard in the 2021 avoided cost proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the \_\_\_ day of \_\_\_\_\_, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Kim Campbell, Chief Clerk