McGuireWoods LLP
501 Fayetteville St.
Suite 500
Raleigh, NC 27601
Phone: 919.755.6600
Fax: 919.755.6699
www.mcguirewoods.com

Andrea R. Kells
Direct: 919.755.6614

McGUIREWOODS

akells@mcguirewoods.com

April 23, 2021

VIA Electronic Filing

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

Re: *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020*
Docket No. E-100, Sub 167

Dear Ms. Campbell,

Enclosed for filing in the above-referenced docket please find the Joint Proposed Order of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina and the Public Staff of the North Carolina Utilities Commission. A Word version of the Joint Proposed Order is being provided via email to briefs@ncuc.net.

Please do not hesitate to contact me if you have any questions. Thank you for your assistance in this matter.

Very truly yours,

/s/Andrea R. Kells

ARK:sjg

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 Rates for Electric Utility Purchases from Qualifying Facilities – 2020	))))	JOINT PROPOSED ORDER OF DOMINION ENERGY NORTH CAROLINA AND THE PUBLIC STAFF

BY THE COMMISSION: These are the 2020 biennial proceedings 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) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings also are held pursuant to the responsibilities delegated to this Commission under N.C.G.S. § 62-156(b) to determine the rates to be paid by electric utilities for power purchased from small power producers as that term is defined in N.C.G.S. § 62-3(27a).

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

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

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

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

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

The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings as required by N.C.G.S. § 62-156. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

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

On August 13, 2020, the Commission issued in this docket an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing (Scheduling Order). Pursuant to the Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC, and together with DEC and DEP, the Utilities), Western Carolina University (WCU), and New River Light and Power Company (New River) were made parties to the proceeding. The Scheduling Order noted that in the Commission's April 15, 2020, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 158 Order) issued in Docket No. E-100, Sub 158, the 2018 biennial avoided cost proceeding (Sub 158 Case), the Commission set forth a number of additional issues to be addressed by the Utilities in their initial filings in this proceeding. In the Sub 158 Order, the Commission also directed Duke to conduct a virtual stakeholder process to address issues related to the addition of energy storage at existing QFs and to report to the Commission in Sub 158 on the results of the stakeholder process by September 1, 2020. The Scheduling Order also stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules, rather than a full evidentiary hearing for the purpose of receiving expert testimony. The Scheduling Order also established deadlines for the filing of petitions to intervene, initial comments and exhibits in response to the Utilities' filings, reply comments, and proposed orders. The Scheduling Order also scheduled a public hearing for February 16, 2021, solely for the purpose of taking nonexpert public witness testimony. Finally, the Scheduling Order required the Utilities to publish notice in newspapers having general circulation in their respective North Carolina service areas and submit affidavits of publication no later than the date of the hearing.

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

On October 20, 2020, the Utilities filed in this docket a notification of intended compliance with N.C.G.S. § 62-156(b), request for a continuance of compliance with certain 2020 filing requirements, and request to modify timing of biennial proceedings. With this filing, the Utilities (1) notified the Commission of their intent to comply with N.C.G.S. § 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 Sub 158 Order, (2) requested a continuance of the additional issues to be addressed by the Utilities as outlined in the Sub 158 Order (Sub 158 Additional Issues) until November 1, 2021, and (3) requested to modify the timing of the biennial avoided cost proceeding, by starting the next full biennial proceeding in 2021 and shifting all future proceedings to odd calendar years.

By order issued October 30, 2020 (Continuance Order), the Commission acknowledged the Utilities' intention to comply with N.C.G.S. § 62-156(b) by filing "streamlined" 2020 avoided cost filings, and directed that (1) the Utilities address the Sub 158 Additional Issues by November 1, 2021, (2) on or by December 7, 2020, the Utilities file a list of the Sub 158 Additional Issues and a timeline for how they intend to address those issues by November 1, 2021, and (3) the Utilities file updates on their progress on the Sub 158 Additional Issues at least every 45 days afterward until the issues are fully addressed.

On November 2, 2020, Duke filed its Joint Initial Statement and Exhibits, which were verified by Glen Snider; and DENC filed its Initial Statement and Exhibits (DENC Initial Statement), which were verified by Jeff Matzen and Eric McMillan, along with DENC's avoided cost information as required by 18 C.F.R. § 292.302(b)(1)-(3). DENC subsequently revised and corrected its proposed standard offer avoided energy rates by filings submitted on December 16 and 23, 2020.

On November 24, 2020, the Commission issued an Order confirming that the hearing scheduled for February 16, 2021, for the purpose of receiving nonexpert public witness testimony would be held remotely via Webex.

On December 7, 2020, DENC and Duke filed progress reports on the Sub 158 Additional Issues.

On December 22, 2020, WCU and New River jointly filed their comments and proposed avoided cost rates, which were verified by Kevin O'Donnell.

On December 29, 2020, the Public Staff filed a request for extensions of time to file initial comments to January 25, 2021, for reply comments to February 26, 2021, and for proposed orders to March 26, 2021, which was granted by Commission order issued on December 30, 2020.

On January 21, 2021, DENC and Duke filed their next status updates on the Sub 158 Additional Issues.

On January 25, 2021, the Public Staff filed its Initial Statement (Public Staff Initial Statement), and SACE, NCCEBA, and NCSEA (together, the Joint Intervenors) filed their Joint Initial Comments (Joint Intervenor Initial Comments).

On January 28, 2021, DENC filed the Affidavit of Publication of notice of hearing.

On February 2, 2021, DENC, Duke, CIGFUR, the Joint Intervenors, NC Small Hydro Group and the Public Staff filed consents to holding the public hearing by remote means.

On February 10, 2021, the Public Staff filed a motion to cancel the public witness hearing scheduled for February 16, 2021, since no member of the public had contacted the Public Staff by email or telephone requesting to testify at the public hearing or submitted comments or statements of position requesting the opportunity to testify at the public hearing.

On February 11, 2021, the Commission issued an order cancelling the public hearing.

On February 12, 2021, Duke filed supplemental revised Energy Rate Calculations and Updated Avoided Energy Rates.

On February 15, 2021, Duke filed the Affidavit of Publication of notice of hearing.

On February 22, 2021, the Joint Intervenors filed a joint motion for an extension of time to file reply comments to March 5, 2021, which was granted by Commission order issued on February 23, 2021.

On March 5, 2021, DENC (DENC Reply Comments), Duke, the Public Staff (Public Staff Reply Comments), and the Joint Intervenors (Joint Intervenors Reply Comments) filed reply comments.

On April 23, 2021, joint proposed orders were filed by the Public Staff together with DENC and by the Public Staff together with Duke. In addition the Joint Intervenors filed a proposed order.

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

FINDINGS OF FACT

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

2. It is appropriate for the Utilities to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive

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

3. DENC should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (2006 Sub 106 Order), except as modified by the Commission in its October 11, 2017 Order Establishing Standard Rates

and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148 (2016 Sub 148 Order).

4. DENC's proposal to continue to use the energy and capacity rate design approved in the Sub 158 Order is reasonable and appropriate for purposes of this proceeding.

5. DENC's proposal to continue to use seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons is reasonable and appropriate for purposes of this proceeding.

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

7. DENC's proposal to continue to charge $0.78/MWh to recover costs incurred by DENC to integrate intermittent, non-dispatchable QFs in its service territory is reasonable and appropriate for purposes of this proceeding.

8. DENC's proposed re-dispatch charge (RDC) avoidance protocol is reasonable and appropriate and should be approved.

9. The installed cost of a combustion turbine (CT) used by DENC is appropriate for use in calculating avoided capacity costs in this proceeding.

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

11. It is reasonable and appropriate to continue to require DENC to utilize a Performance Adjustment Factor (PAF) of 1.07 in its avoided cost calculations for all QFs.

12. DENC has appropriately identified in its 2020 Integrated Resource Plan (IRP) its first avoidable capacity need as 2023, and relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

13. DENC has appropriately incorporated in its calculation of avoided cost rates capacity credits that commence in the first year of the standard offer contract for swine and poultry QFs and in the first year of DENC's capacity need for other QFs in its standard offer rate schedules.

14. DENC's proposed modifications to its standard offer contracts to contemplate the incorporation of energy storage components in QF projects is reasonable and should be approved.

15. DENC has appropriately provided periodic updates to the Commission regarding its progress on the Sub 158 Additional Issues.

16. The Utilities should address the Sub 158 Additional Issues in their 2021 filings.

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

The evidence supporting these findings of fact is found in the DENC Initial Statement and the exhibits attached thereto and the Public Staff Initial Statement. These findings are essentially jurisdictional and administrative and are not contested.

Summary of the Evidence

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

In its Initial Statement DENC proposes to continue to offer Schedule 19-LMP to QFs as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at the avoided cost rates determined by the Commission. Under Schedule 19-LMP, DENC would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kilowatts (kW) would be the PJM Dominion Zone (DOM Zone) Day-Ahead hourly locational marginal prices (LMPs) divided by 10 to convert LMP from $/MWh to cents/kWh, and multiplied by the QF's hourly generation in kWh, while the smaller QFs that elect to supply energy only would be paid the average of the PJM DOM Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (kWh) rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DENC used the PJM Reliability Pricing Model

(RPM) to determine its avoided capacity costs shown as the prices per megawatt per day from PJM's Base Residual Auction for the DOM Zone. As in prior proceedings, DENC also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations. (DENC Initial Statement at 13, Exhibit DENC-4 at 3-7.)

In its Initial Statement the Public Staff reviews and summarizes DENC's proposed rate schedules, including the methods for calculation of rates under Schedule 19-LMP.

Discussion and Conclusions

In the 2016 Sub 148 Order, the Commission approved changes to the standard offer term and eligibility thresholds as a result of changes in the marketplace for QF-supplied power in North Carolina and as a result of the amendments to N.C.G.S. § 62-156 enacted through House Bill 589. The Commission noted that these changes were appropriate to

> reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing protection to ratepayers from overpayment risk and certainty to QFs.

2016 Sub 148 Order at 38. The Commission further indicated that it would "continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to obtain financing on reasonable terms." Id.

In the Sub 158 Order, the Commission found it appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity. The standard offer term and eligibility thresholds for standard offer avoided cost rates and terms were not issues identified to be addressed in this proceeding and no party raised objections to the approval of the Utilities' proposed schedules with respect to these issues. Therefore, the Commission concludes that it is appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity.

In past biennial avoided cost proceedings the Commission ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved. Therefore, the Utilities shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for DENC to continue to offer, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM RPM, subject to the same conditions as approved in the 2006 Sub 106 Order and restated in the 2016 Sub 148 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

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

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used for purposes of calculating energy rates. That rate design, which was approved in the Sub 158 Order, 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. DENC also explains that it continues to allocate its CT costs using the seasonal allocation weighting approved in the Sub 158 Order of 45% summer, 40% winter, and 15% shoulder. (DENC Initial Statement at 4.)

In its Initial Statement, the Public Staff acknowledges that DENC's energy pricing periods remain consistent with the Sub 158 Order and does not raise any concerns with maintaining this rate design. (Public Staff Initial Statement at 27.) The Public Staff also acknowledges that DENC's weighting capacity value between seasons remains consistent with the Sub 158 Order and does not raise any concerns with maintaining this weighting. (Id. at 22.)

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

Discussion and Conclusions

In the Sub 158 Order, the Commission 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 Bruce Petrie in calculating avoided energy and capacity rates in that proceeding. The Commission found that the revised rate design was responsive to the directives in the 2016 Sub 148 Order and the Sub 158 Scheduling Order by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further found that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons were appropriate for use in weighting capacity value between seasons, as these weightings continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder capacity. Sub 158 Order at Finding of Fact No. 43, at 98.

Based upon the foregoing and the entire record herein, and in light of the streamlined nature of this proceeding, the Commission concludes that DENC's proposed rate design, unchanged from the rate design approved in the Sub 158 Order, is appropriate to continue using to calculate rates for DENC's nine pricing periods for purposes of this proceeding. The Commission further concludes that DENC's continued use of the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons, also unchanged from the seasonal allocations approved in the Sub 158 Order, are appropriate for use in weighting capacity value between seasons for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact is found DENC's Initial Statement and Reply Comments, the Initial Statement and Reply Comments of the Public Staff, and the initial and reply comments of the Joint Intervenors.

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC explains that since the Sub 158 Case, it moved from using the PROMOD utility production cost model to the PLEXOS model, which incorporates an 8,760 hourly load profile, an improvement from the PROMOD model used previously, which incorporated a "typical week by month" profile. DENC states that compared to PROMOD, the dispatch from the PLEXOS model utilizing the short-term module better accounts for dispatch constraints on thermal generating units. DENC notes that while it has changed production costing models, the process for developing the avoided energy costs is the same as in previous filings. DENC states that the PLEXOS production cost model is used to derive avoided energy costs for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in DENC's North Carolina service area where QFs are located, plus a fuel hedging benefit and the RDC. DENC states that it used the PLEXOS output results to calculate the levelized on-peak and off-peak long-term fixed energy rates under Schedule 19-FP. (DENC Initial Statement at 4-6.)

Regarding forward commodity prices, DENC states that consistent with past practice it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International (ICF) prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the Sub 158 Case. (Id. at 6.)

DENC explains that consistent with the Commission's conclusions in the 2016 Sub 148 Order and the Sub 158 Order, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that locational marginal prices (LMPs) in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs, and states that it included the historical average congestion differentials for all periods in its calculation of proposed energy rates. (Id. at 6-8.)

DENC also notes that in the December 31, 2014 Order Setting Avoided Cost Input Parameters issued in Docket No. E-100, Sub 140 (Sub 140 Phase One Order), the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC explains that in the December 17, 2015 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 140 (Sub 140 Phase Two Order) 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. Consistent with its proposal in the 2016 Sub 148 Case and the 2018 Sub 158 Case, DENC proposes to continue to use the same Black-Scholes Option Pricing Model to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 Sub 140 Case, with a resulting fuel price hedging value of $0.02/MWh, which was assumed constant for all years of the Schedule 19-FP contract. (Id. at 9.)

Finally, DENC recalls that in the Sub 158 Case, it proposed to adjust avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs—specifically, re-dispatch costs—caused by these generators, and that the Commission approved the proposed RDC, modified pursuant to DENC's agreement with the Public Staff, to be $0.78/MWh. DENC proposes to continue to apply the $0.78/MWh RDC that was approved in the Sub 158 Order for purposes of Schedule 19-FP in this proceeding. (Id. at 10.)

In its Initial Statement the Public Staff states that based on its review of the PLEXOS inputs it 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. The Public Staff confirms that DENC's calculation of avoided energy rates is consistent with the Sub 158 Order, as is DENC's inclusion of avoided fuel hedging values based on the Black-Scholes option pricing model. The Public Staff does not raise any concerns with DENC's forecasted natural gas prices, and states that DENC's calculation of the fuel hedge value is reasonable. (Public Staff Initial Statement at 27-28.)

The Public Staff notes that DENC calculated its proposed avoided energy rates using its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165, and 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 the Regional Greenhouse Gas Initiative (RGGI), effective January 1, 2021. The Public Staff states that while there is some uncertainty regarding the projected future cost of RGGI carbon allowances, the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law. The Public Staff concludes that therefore it is appropriate for DENC to utilize generation expansion Plan B and to include the cost of RGGI carbon allowances in the production cost models that are used to calculate avoided energy rates. The Public Staff also finds reasonable DENC's explanation for the difference between the CO2 price included in DENC's avoided energy rates and the RGGI CO2 price forecasts included in DENC's 2020 IRP. (Id. at 38-39.)

The Public Staff notes further that the CO2 price utilized by DENC to calculate its proposed avoided energy rates also includes a federal CO2 price in addition to the RGGI CO2 price in years 2026 and beyond. The Public Staff argues that the inclusion of a federal CO2 price is inconsistent with prior Public Staff positions and the Commission's Sub 140 Phase One Order that the avoided energy rate should only include "known and verifiable" costs. The Public Staff asserts that as no federal CO2 price currently exists, such costs should not be included in the calculation of avoided energy rates. The Public Staff recommends that DENC calculate its production cost model using a RGGI price forecast without a federal CO2 price, and file revised avoided energy rates. (Id. at 39-40.)

In their initial comments the Joint Intervenors do not make any recommendations specific to DENC. The Joint Intervenors include, however, with their initial comments a report by Crossborder Energy (Crossborder Report), which makes two recommendations for the "utilities." First, the Crossborder Report recommends that the utilities supplement the fundamental forecasts for Henry Hub prices from private consultancies IHS and ICF with a public Henry Hub forecast, and that the IHS/ICF forecasts be averaged with the Energy Information Administration's (EIA) 2020 Annual Energy Outlook forecast of Henry Hub prices. With regard to DENC, this means that DENC would use the average of the EIA and ICF forecasts as its fundamental forecast. (Joint Intervenor Initial Comments, Exhibit A (Crossborder Report) at 2.) Second, the Crossborder Report recommends that the utilities use a fuel hedging model other than the Black-Scholes method. (Id. at 6-10.)

In its reply comments DENC states that it calculated its initially filed avoided energy rates including a federal CO2 price because doing so was consistent with

Alternative Plan B in the 2020 IRP. However, considering the precedent cited by the Public Staff, DENC states that it does not object to the Public Staff's recommendation, and presents the results of running the PLEXOS model using the RGGI price forecast but no federal CO2 price. DENC states that it shared the revised rates and supporting data with the Public Staff and the Joint Intervenors, and that if the Commission agrees with the Public Staff on this issue, DENC does not object to using these revised avoided energy rates. DENC reiterates the Public Staff's recognition 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. As a result, the RGGI Only price forecast in absence of the federal CO2 price will actually slightly increase in years 2026 through 2030. (DENC Reply Comments at 7-8.)

DENC also states that, to the extent that the Crossborder Report's recommendation with regard to fuel forecasts is considered to apply to DENC, it believes its current approach of using the ICF fundamental forecast is appropriate. DENC notes that its use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136), most recently in the Sub 158 Order, and that DENC continues to believe that the ICF forecast of commodity prices is, on its own, appropriate for estimating avoided energy cost rates. DENC explains that ICF forecasts are reputable and respected in the industry and points out that Joint Intervenors have not presented a convincing reason why continued use of the ICF forecast on its own is not reasonable, particularly given the Commission's consistent decisions accepting that approach.

Moreover, DENC indicates that ICF conducts regional forecasts for electricity as well as natural gas and other commodities, which allows DENC to use relevant and correlated forecasts for system modeling purposes. In contrast, DENC explains, using un-correlated forecasts, by for example mixing ICF price forecasts for energy and other commodities with an EIA forecast for Henry Hub, would skew the dispatch and economic value of DENC's natural gas-fired units. (Id. at 9-10.)

DENC also states that to the extent that the Crossborder Report's fuel hedging recommendation is considered to apply to DENC, the alternative methods suggested by the Crossborder Report are not reasonable approaches to calculating avoided hedging costs for North Carolina. DENC explains that this is due to several factors, including but not limited to the fact that both of 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, DENC notes that the Commission concluded in the 2014 Sub 140 Case and again in the Sub 158 Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities. Consistent with this determination, DENC indicates that 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 financial hedge program could extend approximately 18 to 24 months in the future, DENC finds it appropriate to calculate assumed avoided hedging costs using this time frame. (Id. at 10-11.)

In its reply comments the Public Staff states that it has further discussed the federal CO2 issue with DENC, that DENC shared with the Public Staff revised rate schedules consistent with the Public Staff's recommendation, and that the Public Staff agrees that those rates are appropriate for use in this proceeding. (Public Staff Reply Comments at 6.)

With regard to natural gas forecasting, the Public Staff notes that other parties have the ability to cite publicly available forecasts and provide supporting evidence in their comments if they believe that that Utilities' fundamental forecast is inappropriate. Given that the Utilities' long-term fundamental price forecasts are 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, the Public Staff does not believe that the mandated use of publicly available forecasts is warranted at this time. (Id. at 2-3.)

In their reply comments the Joint Intervenors state that they do not oppose DENC's revised rates to remove the federal CO2 costs, but maintaining the RGGI costs. (Joint Intervenors Reply Comments at 2.)

No party objected to DENC's continued application of the LMP adjustment to its avoided energy rates or continued application of the RDC as approved in the Sub 158 Order.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed avoided energy inputs, as modified by DENC's reply comments, are reasonable for the purposes of this proceeding. Therefore, the Commission concludes that these energy inputs should be approved.

In the Sub 140 Phase One Order, the Commission concluded that the calculation of avoided costs should be based on "known and verifiable" costs, finding that the costs of carbon emissions were not sufficiently certain to be included in avoided costs. Sub 140 Phase One Order at Finding of Fact No. 14, at 42-44. Further, the Commission ruled that the generation expansion plans used in the calculation of avoided energy should be based on IRP expansion plans that take into account only known and quantifiable costs. Id. at Finding of fact No. 15, at 42-44. In the Sub 158 Order, the Commission reiterated that costs that are sufficiently known and quantifiable to be impacting the value of QF-supplied energy and capacity must be reflected in the avoided energy and capacity costs in these proceedings. Sub 158 Order at 93. In light of this precedent and DENC's willingness to agree to offer the revised rates, and given the streamlined nature of this proceeding as provided for in the Continuance Order, the Commission concludes that it is reasonable for purposes of this proceeding to approve DENC's revised avoided energy rates based on modelling that excludes the federal CO2 costs that were reflected in DENC's Alternative Plan B as presented in its 2020 IRP.

With respect to the fuel forecast DENC used in its modeling, the Commission agrees that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings, which the Commission has accepted since the 2012 Sub 136 Proceeding, continues to be appropriate. No party raised specific objections to DENC's approach. The Commission declines to accept Joint Intervenors' recommendation regarding fuel forecasts for the reasons discussed in the Public Staff's Reply Comments and DENC's Reply Comments.

With regard to hedging, in the Sub 140 Phase One Order the Commission concluded that there are hedging benefits associated with renewable generation, and that it is appropriate to recognize the hedging costs avoided due to energy purchases from QF generation in calculating avoided energy costs. Sub 140 Phase One Order at Findings of Fact 12 & 13, at 42. In the Sub 140 Phase Two Order, the Commission found it appropriate that the Utilities should calculate these hedging benefits using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the term of the QF contract. Sub 140 Phase Two Order at Finding of Fact 11, at 30-31.

Based on the record in this proceeding, the Commission concludes that DENC has calculated avoided hedging costs appropriately for purposes of this proceeding, and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value of $0.02/MWh, which it assumed constant for all years of the Schedule 19-FP contract. The Commission declines to accept Joint Intervenors' recommendation regarding the hedging value calculation model. DENC's use of the Black-Scholes model to calculate hedging value is consistent with the Sub 140 Phase Two Order and the Sub 158 Order, and given the streamlined nature of this proceeding the Commission declines to reevaluate this precedent at this time.

Additionally, based on the evidence presented by DENC updating the continued disparity in LMPs in its service territory, which no party contested here, the Commission concludes that it continues to be appropriate for DENC to include the historical average congestion differentials for all periods in its calculation of proposed energy costs for purposes of this proceeding.

Finally, in the Sub 158 Case, DENC proposed to adjust the avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs—specifically, re-dispatch costs—caused by these generators. The Commission approved the proposed RDC, modified pursuant to DENC's agreement with the Public Staff to be $0.78/MWh. No party contested DENC's proposal to continue to apply the same RDC for purposes of this proceeding. The Commission therefore concludes that it is appropriate for DENC to continue to apply the RDC as agreed upon in Sub 158 Case for purposes of Schedule 19-FP in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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

Summary of the Evidence

In its Initial Statement, DENC acknowledges that in the Sub 158 Order the Commission directed DENC to file a proposed protocol for avoidance of the RDC. DENC proposes that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD). DENC 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. The output for the case without storage will be the actual metered output of the facility excluding the impact of storage, and the output for the case with storage will be the actual metered output for the facility including the impact of storage. DENC notes that determining the impact of storage will require that the storage device is separately metered. 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 RDC as follows: (1) the percent reduction multiplied by (2) the RDC rate multiplied by (3) the total calendar year output (MWh) of the case with storage. (DENC Initial Statement at 10-11.)

DENC explains 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 RDC 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 RDC reduction as a line item credit with the first payment following the April calculation. (Id.)

In its Initial Statement, the Public Staff states that it does not object to DENC's proposed RDC avoidance protocol, although it notes that the proposed methodology is a "reasonable 'third best' proxy for estimating the reduction in re-dispatch costs" (Public Staff Initial Statement at 34.). The Public Staff states that the proposed protocol is a reasonable proxy largely because DENC's QF load reduction estimates incorporate QF output from the prior day (in addition to other variables), such that over time, as a controlled solar generator (CSG) consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account. (Id. at 34-35.) The Public Staff also presents two preferred options for RDC Avoidance Protocol, while opining on the reasons that they are impracticable at this time or infeasible due to data availability issues. (Id. at 33-35.)

The Public Staff adds, however, that the RDC credit depends on the type of forecast the CSG provides as well as how the CSG dispatches the ESD, and notes that a CSG could provide different types of forecasts depending on whether it wants to use its ESD to "smooth" its output profile or to shift energy from off-peak to on-peak hours. The Public Staff questions whether ratepayers would actually benefit more from energy shifting dispatch than from smoothing dispatch, even though a CSG that is shifting energy would qualify for a higher RDC credit than a CSG that is seeking to smooth output. In order to address its concerns, 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. The Public Staff states that these biennial reports would be similar to the Solar Integration Services Charge (SISC) Avoidance reports recommended by NCSEA, NCCEBA, and the Public Staff for Duke in the Sub 158 Case. The Public Staff also recommends that DENC 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, and notes that it made the same request of DEP and DEC in the Sub 158 Case. The Public Staff suggests that should evidence emerge that CSGs are able to game their forecasts and output to obtain excessive RDC credits, or if a large number of QFs install an ESD to smooth volatility, the Public Staff may recommend that DENC take measures to address those issues in future avoided cost proceedings. (Id. at 35-37.)

In their reply comments, the Joint Intervenors disagree with the Public Staff's suggestion that there is a risk that CSGs might game the RDC, and also disagree with the Public Staff's comments on CSGs engaging in energy-shifting receiving higher RDC credits than CSGs engaging solely in energy smoothing. Joint Intervenors did not raise any objection to the proposed RDC avoidance protocol. (Joint Intervenors Reply Comments at 5-6.)

In its reply comments, DENC states that its proposed RDC Avoidance Protocol is a reasonable proxy for estimating the reduction in re-dispatch costs incurred by CSGs. DENC explains that the proposed Protocol can decrease the costs to customers by improving the load forecasts; as CSGs consistently deliver more predictable output, DENC's forecasting tools will incorporate the data in the load forecast process. DENC does not object to the Public Staff's recommendation of monitoring, for CSGs that attempt to avoid the RDC, such CSG's forecasts and behavior and including that information and an analysis of actual solar volatility of CSGs in DENC's service territory in its future biennial avoided cost filings. DENC clarifies that its monitoring and reporting obligation would be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs. DENC also notes that, if the Commission adopts this recommendation, DENC plans to monitor this information on an annual basis, consistent with the RDC avoidance protocol structure of using annual forecasts. DENC also does not object to the Public Staff's recommendation that DENC monitor CSGs seeking RDC avoidance in future fuel rider proceedings, subject to the same clarification that this obligation would be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs. (DENC Reply Comments at 2-6.)

Discussion and Conclusions

In the Sub 158 Order, in addition to accepting the RDC, the Commission noted the potential for a QF to justify an exception from the RDC and directed DENC to file a proposed protocol for avoidance of the RDC similar to protocols that the Commission directed Duke to file with regard to its integration services charge. Sub 158 Order at 113.

Based on the evidence presented, the Commission concludes that DENC's proposed RDC avoidance protocol is appropriate for use in this proceeding. The Commission finds reasonable DENC's proposal that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an ESD and that the proposed protocol is a reasonable proxy for estimating the reduction in re-dispatch costs incurred by CSGs. The Commission also relies on the Public Staff's determination that the protocol is reasonable in part because DENC's QF load reduction estimates incorporate QF output from the prior day (in addition to other variables), such that over time, as a CSG consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account. For these reasons the Commission concludes that DENC has complied with the Sub 158 Order directive to file a proposed protocol for avoidance of the RDC.

On October 17, 2019, the Commission issued a Supplemental Notice of Decision in the Sub 158 Case in which it, among other things, directed Duke to file with the Commission proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC. On November 18, 2019, Duke filed its requirements for the avoidance of SISC, and the Public Staff and other parties filed comments in July 2020, which included the recommendations noted by the Public Staff and DENC in its filings in this case regarding monitoring and reporting of data related to SISC avoidance. As noted in the Order Requiring Additional Information issued in Docket Nos. E-100, Sub 158 and Sub 101 on March 29, 2021, the Commission has determined that additional information is necessary in order for the Commission to resolve certain issues related to the SISC, and directed comments to be filed on these issues, which were filed on April 13 and 27, 2021. These issues are currently under consideration by the Commission.

The Commission concludes that, if any CSGs that are actually paired with ESDs seek to avail themselves of the RDC avoidance protocol, the information that the Public Staff requests DENC to monitor and provide may be helpful for purposes of evaluating the results of the protocol in the future. However, since the Commission continues to consider the SISC and SISC avoidance, the Commission encourages DENC and the Public Staff to continue to discuss the information requested by the Public Staff with regard to the RDC avoidance and, to the extent appropriate, DENC should address the proposed monitoring and reporting of this information in its November 1, 2021 avoided cost filing. In discussing this issue and addressing it in DENC's next avoided cost filing, DENC and the Public Staff should, to the extent relevant, account for any Commission decision with respect to the Public Staff's reporting requirements regarding Duke's SISC Avoidance protocol, taking into consideration the specific nature of DENC's metering and other data monitoring processes as they may differ from those used by Duke. If DENC or the Public Staff proposes, based on this information or for another reason, to modify the structure or application of the RDC avoidance protocol in a future biennial avoided cost proceeding the Commission will consider any such proposed modifications at that time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

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

Summary of the Evidence

In its Initial Statement DENC indicates that consistent with the method used in its compliance filing in the Sub 158 Case, it used the applicable costs of the Greensville 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. DENC states further that for the remaining costs, including construction and owner costs, it utilized the PJM cost of new entry estimates, 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. DENC indicates that it also made several adjustments to the Brattle Study results to tailor those results to meet the requirements of the Sub 140 Phase One Order. (DENC Initial Statement at 14-15.)

In its Initial Comments the Public Staff indicates that it reviewed the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates and finds them reasonable. (Public Staff Initial Comments at 21.)

Discussion and Conclusions

In the Sub 140 Phase One Order, the Commission determined:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes 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. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Sub 140 Phase One Order at 48.

Based upon the foregoing evidence and the entire record in this proceeding, the Commission concludes that DENC appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT and that its source information was tailored in a manner consistent with the guidance previously provided by the Commission. The Commission therefore also concludes that the CT cost information used by DENC is reasonable and appropriate for purposes of calculating avoided capacity costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

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

<u>Summary of the Evidence</u>

In its Initial Statement, DENC explains that in the 2016 Sub 148 Order, the Commission approved DENC's proposal to eliminate from its avoided energy rates the 3% adder that had historically been included in avoided energy rates. DENC also explains that 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 DENC 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 proceeding, DENC's avoided energy rates continue to reflect the elimination of the line loss adder. (DENC Initial Statement at 9.) In its initial status update on the Sub 158 Additional Issues filed on December 7, 2020, DENC states that prior to joining with Duke in the October 20, 2020, joint request, DENC had updated its evaluation of the amount of backflow on the North Carolina portion of its service area, but did not include the updated study with the streamlined filing submitted on November 2, 2020, based on its determination that the analysis was included in the "Sub 158 Additional Issues" to be included in the November 2021 filing. DENC states that the updated study shows that the number of transformers experiencing backflow has increased as more distributed solar generation has become operational. Specifically, of the 41 transformers with connected distributed solar, the study shows 24 realizing consistent backflow (58.5%), an increase from the 16 out of 38 transformers (42%) consistently experiencing backflow in the 2018 study. DENC notes that it plans to update the backflow study again during the third quarter of 2021 for purposes of the November 2021 biennial avoided cost filing.

In its Initial Statement the Public Staff states that for the reasons articulated in the 2016 Sub 148 Order, it is appropriate for DENC to continue to have its line loss adder removed from its standard offer avoided costs rates. The Public Staff explains that 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 also states that it will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings, and recommended that the Commission direct the Utilities to continue to file information to support the removal or inclusion of the line loss adder in proposed avoided cost rates in future avoided cost proceedings. (Public Staff Initial Statement at 48-49.)

Discussion and Conclusions

Pursuant to 18 C.F.R. § 292.304(e)(4), in determining avoided costs "the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity," shall, to the extent practicable, be taken into account. In the 2016 Sub 148 Order, the Commission concluded that line losses may not exist if power purchased from a distribution-connected QF is backfeeding to the substation, and the Commission directed the Utilities to further evaluate this issue in the Sub 158 Case. In the Sub 158 Order, the Commission determined that backflows are continuing to occur with regularity on a number of DENC's distribution system circuits and that backflows will continue to increase over time. The Commission decided that this greatly reduces or eliminates the benefits of the solar QFs' line loss avoidances, and that it was appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer. Sub 158 Order at 35-36.

Based on the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer for the purposes of this streamlined proceeding. The Commission also accepts the Public Staff's recommendation that the Utilities continue to file information to support the removal or inclusion of the line loss adder in proposed avoided cost rates in future avoided cost proceedings, which DENC has already indicated through its Sub 158 Additional Issues status updates that it plans to do.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

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

Summary of the Evidence

In its Initial Statement, DENC explains that in the 2016 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 the next biennial avoided cost proceeding. In its 2018 initial statement, DENC proposed to use the metric Equivalent Availability (EA) to determine the PAF. As DENC explained, 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 has continued to apply the 1.07 PAF that was approved in the Sub 158 Order for purposes of this filing. (DENC Initial Statement at 19-20.) In its initial statement, the Public Staff acknowledges that DENC proposes to continue to use a PAF of 1.07.

In its Sub 158 Additional Issues updates filed on December 7, 2020, January 21, 2021, and March 8, 2021, DENC reports that it has met with the Public Staff to discuss indices to support development of the PAF and that it plans to continue coordinating with the Public Staff on this issue.

Discussion and Conclusions

As discussed in the Sub 158 Order, the Commission has consistently recognized that because standard avoided capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours, without any reasonable opportunity to experience outages during each peak period, to receive the total available avoided capacity payment. Recognizing that the Utilities' generating units experience outages and do not operate 100% of the time, the Commission therefore has ordered the Utilities to apply a PAF, or a simple capacity multiplier, in calculating avoided capacity rates paid to QFs in previous avoided cost proceedings. In the 2016 Sub 148 Order the Commission found that the methodology used to calculate the PAF should include greater precision than in past proceedings and required the Utilities to calculate the PAF using a system availability metric representing the reliability of the Utilities' respective systems during peak periods. The Commission determined in the Sub 158 Case that the evidence supported calculating the PAF based upon a metric or metrics that assess generating unit "availability" and that the methodology used to calculate generating unit availability should be based upon an informed discussion of utility system planning and load forecasting.

In the Sub 158 Order, the Commission found that the PAFs proposed in the Utilities' respective initial statements were appropriate based on this standard. The Commission also directed the Utilities, with Public Staff input, to evaluate the appropriateness of using other reliability indices, specifically the Equivalent Unplanned Outage Rate (EUOR) metric, to support development of the PAF prior to the next biennial avoided cost filing. The Commission also adopted the Public Staff's recommendation to require the Utilities to continue to use three (as used by DENC) to five (as used by Duke) years of historic outage rate data to support the PAF. Finally, the Commission acknowledged that there is no possibility that a run-of-river hydroelectric QF will seek to avail itself of the opportunity to sell electric power from its facility to DENC, and therefore, the Commission concluded that DENC was not required to address related issues in the next avoided cost proceeding. Sub 158 Order at 40-42.

In its Scheduling Order in this proceeding, the Commission set forth a number of issues to be addressed by the Utilities in their Initial Statements, including the use of other reliability indices, specifically the EUOR metric, to support development of the PAF. In its Order Granting Continuance, however, the Commission permitted the Utilities to address this issue in their next biennial full avoided cost proceeding initial statements to be filed on November 1, 2021.

Based upon the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to continue to use a PAF of 1.07 in its avoided cost calculations for all QFs and to address the appropriateness of other reliability indices in its initial statement to be filed on November 1, 2021.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

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

<u>Summary of the Evidence</u>

In its Initial Statement, DENC states that on September 1, 2020, in Docket No. E-100, Sub 165, DENC filed an addendum to its 2020 IRP that was submitted in that docket on May 1, 2020, stating that the next year of undesignated capacity need for DENC is 2023. DENC explains that, consistent with the Commission's findings in the Sub 158 Order and DENC's statement of capacity need, its calculation of the seasonal levelized rates therefore includes no avoided capacity costs through 2022 since DENC's 2020 IRP shows the first avoidable capacity in 2023. (DENC Initial Statement at 18.)

In the Public Staff's Initial Statement, the Public Staff notes that 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 beginning with the 2020 IRP and that DENC's IRP shows the first deferrable capacity need in 2023. The Public Staff explains that, therefore, QFs located in DENC'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 2023.

<u>Discussion and Conclusions</u>

N.C.G.S. § 62-156(b)(3) 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 and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power….” In the Sub 158 Order, the Commission explained that in its August 27, 2019 Order on the 2018 IRPs in Docket No. E-100, Sub 157, the Commission found the IRPs of DEC, DEP, and DENC to be reasonable for planning purposes, and found that the Utilities appropriately identified their first avoidable capacity needs in their 2018 IRPs, and therefore, complied with N.C.G.S. § 62-153(b)(3). The Commission also determined that, beginning with the 2020 IRP, it was 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. Sub 158 Order at 46.

Based on the foregoing, the Commission concludes that DENC's addendum to its 2020 IRP submitted on September 1, 2020 in Docket No. E-100, Sub 165 serves this purpose, that DENC's next year of undesignated capacity need is 2023, and that DENC appropriately relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

<u>Summary of the Evidence</u>

In its Initial Statement, DENC acknowledges the Commission's directive in the Sub 158 Order for the Utilities to "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. For other types of QF generation, the Utilities shall recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified" in each Utilities' respective most recent IRP." DENC states that its standard offer rate schedules have been revised to include these recognitions. (DENC Initial Statement at 19.)

In its Initial Statement, the Public Staff explains that 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 states that based on its review of these capacity credits, and other assumptions, incorporated in Duke's and DENC's proposed rates for swine and poultry QFs, it finds them reasonable for the determination of Duke's and DENC's avoided capacity credits. (Public Staff Initial Statement at 23.)

Discussion and Conclusions

In its Sub 158 Order, the Commission found House Bill 589's and House Bill 329's recent amendments to N.C.G.S. § 62-156(b)(3) to be controlling on the issue of when renewing QFs can be considered to provide capacity value to the Utilities. As discussed above, House Bill 589 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 and the identified need can be met by the type of QF resource based upon its availability and reliability of power . . .," but expressly carves swine and poultry waste generation out from this requirement based upon their designated need to meet REPS compliance. Section 3(a) of House Bill 589 adds to N.C.G.S. § 62-156(b)(3) an additional carve out for "legacy" hydroelectric QFs of 5 MW or less selling and delivering power under QF PPAs in effect as of July 27, 2017. The Commission noted the further direction provided by Section 3(b) of House Bill 329, which emphasized this distinction by stating that "the exception for hydropower small power producers from limitations on capacity payments established in G.S. 62-156(b)(3), as amended by Section 3(a) of this act, shall not be construed in any manner to affect the applicability of G.S. 62-156(b)(3) as it relates to any other small power producer." Sub 158 Order at 50-52.

The Commission found that the clear intent of the General Assembly as shown through House Bill 589 and House Bill 329 is to treat swine and poultry waste QF resources and legacy small hydro QF resources differently from other QFs in regard to valuing their ability to avoid the Utilities' projected capacity needs to serve system load during the future IRP planning period. The Commission concluded that it is appropriate for the Utilities to recognize any new commitment by a swine or poultry waste QF generator or a legacy small hydroelectric facility 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, obligating itself to sell and deliver its full energy and capacity output over a future contract term as helping the

Utilities avoid a designated future capacity need beginning in the first year of the new QF PPA, pursuant to the N.C.G.S. § 62-156(b)(3), as amended by House Bill 329. Id.

Based upon the evidence herein, the Commission concludes that DENC's Schedule 19-FP and Schedule 19-LMP contain language to appropriately reflect the requirements in House Bill 589 and House Bill 329 with respect to capacity payments for a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less with a PPA in effect as of July 27, 2017, and that DENC has therefore complied with this directive from the Sub 158 Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in the DENC Initial Statement and Exhibits and the entire record herein.

Summary of the Evidence

In its Initial Statement, DENC proposes limited additional provisions for its Schedule 19-FP and Schedule 19-LMP standard contracts and terms and conditions that contemplate the incorporation of energy storage components in QF projects. DENC explains that it is proposing these limited changes at this time, even though it made no such proposals in the Sub 158 Case, as it recognizes 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 notes that it relied on the Commission's approval in the Sub 158 Order of similar provisions in the Duke standard offer contracts in making these proposals, which are intended to provide guidance to QFs as to how DENC will address projects with energy storage components.

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

Second, DENC 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 its prior written consent. As stated in the new provision, "Material Alteration" means a modification to the QF facility that renders the facility description specified in the contract inaccurate in any material sense as determined by the 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. The new provision also states that the 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. DENC notes that this provision was approved by the Commission in the Sub 158 Order for use in Duke's standard avoided cost contracts, and that DENC is proposing to include it in its standard contracts to provide the same guidance regarding how modifications to QF facilities will be addressed under those agreements. (DENC Initial Statement at 20-21.)

The Public Staff and Joint Intervenors did not raise any issues with DENC's proposed changes to its standard offer PPA Terms and Conditions.

Discussion and Conclusions

In the Sub 158 Order, the Commission discussed proposed changes in the terms and conditions of Duke's standard offer contracts to address modifications to a QF that seeks to install battery storage or otherwise increase its energy output. The Commission determined that for existing PPAs, material changes to the capacity of the QF should be authorized by the utility, although the evaluation of such change should be treated in a commercially reasonable manner. The Commission agreed that regular maintenance and repair of a facility after a storm, or similar instances that occur on a normal basis, should be treated within the normal course of operations and should not be considered a change that would allow the utility to void the existing PPA. The Commission also found that QFs often complete maintenance on their facilities that could increase the energy or capacity such as replacing existing solar panels with newer panels, or re-paneling, without first obtaining the consent of the utility, and that this type of maintenance should not trigger a default of the existing PPA. The Commission concluded that the newly defined term "Material Alteration" added to Duke's standard offer contract terms and conditions appropriately defined the instances of what is a material change that requires the utility's consent, and that without consent may lead to default of an existing PPA. The Commission noted that the term expressly allows replacement of "like-kind" equipment and provides that material alterations will be evaluated by DEC and DEP in a "commercially reasonable manner." Sub 158 Order at 129-130.[1]

[1] The Sub 158 Order also discussed in detail the issue of how to compensate existing QFs for new storage capacity and energy and directed the Utilities to engage in a stakeholder process on that issue and submit a report. The Utilities submitted their report in September 2020, and comments were exchanged on the report. The Commission continues to consider those pleadings along with those received in response to the March 29, 2021, Order Requiring Additional Information (Docket Nos. E-100, Sub 101 and 158). That issue is separate from the limited proposals that DENC made in this proceeding.

The proposed changes to DENC's standard offer PPAs terms and conditions largely mirror the same proposed changes to Duke's standard offer PPAs in the Sub 158 Case that the Commission approved in the Sub 158 Order. Specifically, DENC's new proposed provision to Article 7 of its standard offer contracts provides that any material alteration to a QF facility shall require DENC's prior written consent. "Material Alteration" is defined similarly to Duke's definition in the Sub 158 Case and would include the addition of an Energy Storage Device or a modification that increases the output of the facility. The new provision also states that the 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. No party has raised any concern with this proposed revision to DENC's standard offer contracts.

DENC's Energy Storage Device Addendum will provide DENC and QFs seeking to sell their output to DENC with basic information regarding an ESD that a QF proposes to include in its facility's design. No party has raised any concern with DENC's proposed addition of the Energy Storage Device Addendum as Exhibit G to its standard offer contracts.

Based upon the evidence herein, the Commission concludes that DENC's proposed modifications to its Schedule 19-FP and Schedule 19-LMP standard offer PPAs are reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

The evidence supporting these findings of fact is found in the DENC Initial Statement, DENC's Sub 158 Additional Issues compliance filings, and the entire record herein.

Summary of the Evidence

DENC filed status updates on its progress with regard to the Sub 158 Additional Issues on December 7, 2020, January 21, 2021, March 8, 2021, and April 22, 2021. In its status updates, DENC provides updates to the Commission on its progress with discussions with the Public Staff regarding certain of the Sub 158 Additional Issues, including the metric for determining the PAF and transmission and distribution impacts of QFs. DENC has also explained its position on or consideration of particular issues, including its previous and planned future updated line loss studies, installed capacity cost increments and decrements, and timing for delivery of LEO forms for existing QFs. In each of its updates, DENC has presented its plans for further considering these issues as well as the implications of FERC Order No. 872 for PURPA implementation in North Carolina during the time preceding its November 1, 2021 filing and addressing the issues in that filing.

Discussion and Conclusions

In the Sub 158 Order, the Commission set forth a number of additional issues (the Sub 158 Additional Issues) to be addressed by the utilities in their initial filings in the next biennial avoided cost proceeding. In the Scheduling Order, the Commission directed the Utilities to address those issues in their initial filings in this docket. In addition, the Commission noted that FERC issued Order No. 872 on July 16, 2020, in Docket Nos.

RM19-15-000 and AD16-16-000, potentially driving additional changes to PURPA implementation and the determination of avoided cost rates in North Carolina.

In the Continuance Order, the Commission acknowledged the Utilities' intention to comply with N.C.G.S. § 62-156(b) by filing "streamlined" 2020 avoided cost filings, and directed that (1) the Utilities address the Sub 158 Additional Issues by November 1, 2021, (2) on or by December 7, 2020, the Utilities file a list of the Sub 158 Additional Issues and a timeline for how they intend to address those issues by November 1, 2021, and (3) the Utilities file updates on their progress on the Sub 158 Additional Issues at least every 45 days afterward until the issues are fully addressed (Progress Update).

Based on the evidence contained herein, the Commission determines that DENC has complied with the requirements of the Sub 158 Order in filing its Progress Updates on the Sub 158 Additional Issues to date. Consistent with the Continuance Order, DENC shall continue filing its Progress Updates until the issues are fully addressed or until the filing of proposed rates and terms on November 1, 2021, whichever is earlier and, to the extent relevant to DENC, address the Sub 158 Additional Issues in its November 2021 filing. As contemplated by the Scheduling Order, the Commission recognizes that the Utilities may make proposals stemming from FERC Order No. 872 and its potential effect on PURPA implementation in North Carolina, and the Commission will consider any such proposals in the next biennial proceeding as appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DENC shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs contracting to sell 1 MW or less capacity. The standard ten-year

levelized rate option should include a condition making contracts renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration;

2. That DENC shall continue to offer, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's 2006 Sub 106 Order and most recently restated in the 2018 Sub 158 Order;

3. That DEC, DEP, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as

beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding;

4. That DEC, DEP, and DENC shall continue to calculate avoided capacity costs using the Peaker Method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity to QFs other than those using swine or poultry resources, or hydroelectric resources greater than 5 MW, in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3);

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

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

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

8. That DENC shall continue to use the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons that were approved in Sub 158 Case in calculating rates in this proceeding;

9. That DENC's proposed input assumptions to be used in determining its proposed energy rates, including those related to fuel forecasting methodology, fuel hedging activities, and the LMP adjustment shall be used in calculating DENC's rates in this proceeding;

10. That DENC shall continue to use a re-dispatch charge of $0.78/MWh in calculating DENC's rates in this proceeding;

11. That DENC's proposed re-dispatch charge avoidance protocol is approved;

12. That DENC's proposed modifications to its standard offer contracts to add an energy storage device addendum and material alteration provisions are approved;

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

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _______________, 2021.

NORTH CAROLINA UTILITIES COMMISSION

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *Joint Proposed Order* filed in Docket Nos. E-100, Sub 167 were served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 23rd day of April, 2021.

/s/Andrea R. Kells

Andrea R. Kells
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601
(919) 755-6614 (Direct)
akells@mcguirewoods.com

Attorney for Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina