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September 4, 2019

VIA ELECTRONIC FILING

Ms. Janice Fulmore, Deputy Clerk
Ms. Antonia Dunston, Deputy Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018
Docket No. E-100, Sub 158

Dear Deputy Clerks:

Enclosed for filing in the above-referenced docket please find the *Proposed Order* of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina.

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

Very truly yours,

/s/Andrea R. Kells

ARK:mth

Enclosure

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Biennial Determination of Avoided Cost	)	PROPOSED ORDER OF DOMINION
Rates for Electric Utility Purchases from	)	ENERGY NORTH CAROLINA
Qualifying Facilities – 2018	)	

HEARD: July 15, 2019, at 1:30 p.m., July 16, 2019, at 9:30 a.m., July 17, 2019, at 9:30 a.m., July 18, 2019, at 11:00 a.m., and July 19, 2019, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

APPEARANCES:

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For the Using and Consuming Public:

Tim R. Dodge
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BY THE COMMISSION: These are the current 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 G.S. 62-156(b) to establish rates for small power producers as that term is defined in 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. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status under Section 210 of PURPA. 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

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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.

This Commission determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. 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 which they interconnect. The Commission has also reviewed and approved other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also is a result of the mandate of 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 therein. Such standards generally approximate those prescribed in FERC regulations regarding factors to be considered in the determination of avoided cost rates.

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PROCEDURAL HISTORY

On June 26, 2018, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing in the instant proceeding (Scheduling Order). The Scheduling Order made Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (together, Duke), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC), Western Carolina University (WCU), and Appalachian State University, d/b/a, New River Light and Power Company (New River) parties to the proceeding in order to establish the avoided cost rates each is to pay for power purchased from QFs pursuant to Section 210 of PURPA and the associated FERC regulations and G.S. 62-156. 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 required that DEC, DEP, DENC, WCU, and New River file the statements and exhibits specified in the Scheduling Order on or before November 1, 2018. The Scheduling Order also requested that other persons desiring to become formal parties to the proceeding petition the Commission for leave to intervene and file with the Commission the comments and exhibits they wished to present on or before January 7, 2019.

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The Scheduling Order also directed that the electric utilities and intervenors could file reply comments on or before February 15, 2019, and that parties were requested to file proposed orders on or before March 8, 2019. A public hearing solely for the purpose of taking non-expert public witness testimony was scheduled for February 19, 2019.

The North Carolina Sustainable Energy Association (NCSEA), North Carolina Clean Energy Business Association (NCCEBA), Ecoplexus Inc. (Ecoplexus), Carolina Utility Customers Association, Inc. (CUCA), the Southern Alliance for Clean Energy (SACE), North Carolina Small Hydro Group (Hydro Group), Cube Yadkin Generation LLC (Cube Yadkin), and NC WARN, Inc. (NC WARN) filed petitions to intervene, all of which were granted by the Commission. The Public Staff's intervention and participation in this proceeding is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). Patrick and Belinda Flynn petitioned to intervene on January 7, 2019. DENC filed a Motion to Deny the petition on January 16, 2019, and the Commission denied the petition on January 18, 2019.

On November 1, 2018, DENC and Duke filed Initial Statement and Exhibits along with avoided cost information as required by 18 C.F.R. 292.302(b)(1)-(3).

On December 31, 2018, the Public Staff filed a Motion for Extension and Modified Procedural Schedule. The Commission granted the Motion for Extension on January 4, 2019, extending the time for filing of initial comments by all parties other than the Utilities, and determined that the issues related to the modified procedural schedule would be addressed in a separate order. Also on January 4, 2019, NCSEA filed a Response to Public Staff's Motion for Extension and Revised Procedural Schedule and filed its own Motion for Modified Procedural Order on Testimony. Duke filed a response

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to NCSEA's requested modification on January 10, 2019. On January 25, 2019, the Commission issued an Order on Procedural Schedule and Requiring Report, which modified comment and proposed order deadlines and also required Duke to confer with other parties to this proceeding and file a report with the Commission identifying issues: (1) where agreement exists or can be reasonably expected to be reached; (2) in controversy, but do not merit an evidentiary hearing and; (3) in controversy and meriting consideration at an evidentiary hearing (Procedural Report).

On January 9, 2019, DENC filed its Affidavit of Publication of notice of hearing.

On January 16, 2019, Duke filed a Motion to Establish Discovery Guidelines that DENC supported. SACE and NCSEA filed a Joint Response to the motion on January 23, 2019.

On February 7, 2019, the Public Staff filed a Motion for Extension for the date to file initial and reply comments and the Procedural Report. The Commission granted this motion on February 8, 2019.

On or before February 12, 2019, NC WARN, the Hydro Group, Cube Yadkin, NCSEA, SACE, and the Public Staff filed initial comments. The initial comments of NCSEA and SACE were accompanied by affidavits.

On February 19, 2019, a Public Hearing was held. Public witnesses Mark W. Bishophric, Kevin Edwards, and Michael Matthews gave testimony at the public hearing. In addition, 3 consumer statements of position were filed in this docket.

On February 20, 2019, Duke filed a Joint Motion for Extension of Time to file reply comments. The Commission granted the motion on February 22, 2019.

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On March 7, 2019, DENC filed Revised Proposed Standard Offer Avoided Cost Rate Schedules. On March 14, 2019, DENC filed a correction to its March 7, 2019 filing.

On March 18, 2019, Duke and DENC (Utilities) filed a Joint Motion for Extension of Time to file reply comments. The Commission granted the motion on March 19, 2019.

On March 27, 2019, the Public Staff, DENC, Duke, NCSEA, SACE, and the Hydro Group filed reply comments.

On April 10, 2019, Duke filed the Procedural Report.

On April 18, 2019, Duke and the Public Staff entered a partial settlement regarding Duke's avoided energy and capacity rate design.

On April 24, 2019, the Commission issued an Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule (Procedural Order). The Procedural Order specified the issues to be addressed by expert witness testimony and directed that the remaining issues in this proceeding be addressed in the proposed orders filed by the Utilities and intervenors.

On May 21, 2019, DENC filed the direct testimony of Bruce E. Petrie. Also on May 21, 2019, Duke filed the direct testimony and exhibits of Glen A. Snider, Steven B. Wheeler, David B. Johnson, and Nick Wintermantel.

Also on May 21, 2019, Duke and the Public Staff entered into a partial settlement regarding Duke's proposed Solar Integration Services Charge (SISC).

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On June 14, 2019, the Commission issued an Order Requiring Supplemental Testimony and Allowing Responsive Testimony regarding the contractual impacts of adding battery storage at various stages of a QFs development.

On June 21, 2019, the Public Staff filed the testimony of John R. Hinton and Jeff Thomas. On the same date, NCSEA filed the testimony of Dr. Ben Johnson and Carson Harkrader and the testimony and exhibit of R. Thomas Beach. Also on June 21, SACE filed the testimony and exhibits of Brendan Kirby and James Wilson.

On June 25, 2019, DENC filed the Supplemental Testimony of James M. Billingsley. Also on June 25, 2019, Duke filed the Supplemental Testimony of Glen A. Snider.

On July 3, 2019, DENC filed the Rebuttal Testimony of Bruce E. Petrie. On the same date, Duke filed the Rebuttal Testimony of Glen A. Snider, Steven B. Wheeler, David B. Johnson, and Nick Wintermantel.

Also on July 3, 2019, Public Staff filed the Responsive Testimony of Dustin Metz. On the same date NCSEA filed the Responsive Testimony and exhibit of Tyler Norris and SACE filed the Responsive Testimony of Devi Glick.

On July 5, 2019, Ecoplexus filed the Supplemental Testimony of Michael R. Wallace as well as a Motion to Accept Michael R. Wallace's Supplemental Testimony as Timely Filed.

On July 10, 2019, Duke filed the Order of Witnesses, Estimates of Cross Examination Times, and Witness List.

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On July 11, 2019, DENC filed the Supplemental Rebuttal Testimony of James M. Billingsley. On the same date, Duke filed the Joint Supplemental Rebuttal Testimony of witnesses Glen A. Snider, Steven B. Wheeler, and David B. Johnson.

Also on July 11, 2019, NCSEA filed a Motion to Excuse Witness Carson Harkrader. On the same date, SACE filed a Motion for Witness to be Excused from Appearance at Evidentiary Hearing for James Wilson.

The evidentiary hearing was held as scheduled on July 15, 2019, through July 19, 2019. Duke presented the testimony of witnesses Snider, Wheeler, Johnson, and Wintermantel. DENC presented the testimony of witnesses Petrie and Billingsley. NCSEA presented the testimony of witnesses Johnson, Beach, and Norris.[1] SACE presented the testimony of witnesses Kirby, Wilson, and Glick. Ecoplexus presented the testimony of witness Wallace. Public Staff presented the testimony of witnesses Hinton, Thomas, and Metz. The pre-filed testimony and exhibits of those witnesses who testified at the hearing or whose testimony was stipulated to was copied into the record as if given orally from the stand.

On August 28, 2019, the Public Staff filed a request for extension of time to file proposed orders until September 4, 2019, which was granted by Commission order issued the same day.

Proposed orders were filed by the parties on September 4, 2019.

Various filings made and orders issued in this proceeding are not discussed in this order, but are included in the record of this proceeding.

[1] On July 15, 2019, Duke opposed NCSEA's motion to excuse witness Harkrader from appearing at the hearing. Chair Mitchell took the motion and Duke's opposition, made orally at the hearing, under advisement and denied the motion after the presentation of testimony on July 19, 2019. Tr. Vol. 7 at 155-156.

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

FINDINGS OF FACT

1. For nonrenewable QFs, it is appropriate for the Utilities to continue to be required 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. The proposed changes to DENC's energy and capacity rate design are appropriate to send better price signals to incentivize QFs to better match the generation needs of Utilities and should be used in calculating DENC's avoided energy and capacity rates in this proceeding.

4. 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 2016 biennial avoided cost proceeding (2016 Case).

5. DENC's revised proposed CT cost seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are appropriate for use in weighting capacity value between seasons, and should be used in calculating DENC's avoided capacity rates in this proceeding.

6. The input assumptions used by DENC for the purpose of determining its proposed avoided energy rates, including the avoided costs related to fuel hedging activities and the LMP adjustment, are appropriate for use in this proceeding.

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7. DENC's proposed re-dispatch charge complies with the Commission's previous orders and is consistent with PURPA.

8. As modified, DENC's proposed re-dispatch charge of $0.78/MWh is a reasonable and appropriate mechanism to recover the re-dispatch costs imposed on DENC by intermittent, non-dispatchable QFs in its service territory, that properly considers both the costs and benefits of these QFs, and should be accepted for purposes of this proceeding.

9. DENC's proposed annual capacity payment cap is a reasonable and appropriate measure to capture the value of capacity offered by intermittent, non-dispatchable QFs in its service territory, as directed by the Commission in its final order in the 2016 Case (2016 Order).

10. DENC's installed combustion turbine (CT) cost calculation of $559.8/kW is reasonable and appropriate. It is appropriate for the Utilities to consider cost increments and decrements to publicly available cost estimates of CT costs associated with the use of brownfield sites in future biennial proceedings.

11. DENC's identification of its first avoidable capacity need in 2022 based on its 2018 Integrated Resource Plan (IRP) is reasonable and appropriate; the Utilities should include a statement of need for capacity in their next IRPs.

12. QFs whose PURPA contracts are expiring should notify the Utilities between six months and one year in advance of the contract expiration date of their intent to renew; such QFs are not entitled to the same rates, terms, or conditions as those in the relevant expiring contract.

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13. NCSEA's recommendation to calculate avoided cost rates using a later in-service date for standard offer QFs is not reasonable.

14. DENC's proposed Performance Adjustment Factor (PAF) of 1.070 is reasonable and appropriate. The Utilities should consider evaluating whether other approaches to determining a PAF would be appropriate in their initial filings in the next avoided cost proceeding.

15. DENC's continued elimination of the line loss adjustment from standard offer avoided cost payments to distribution connected QFs is reasonable and appropriate in light of continued regular occurrence of backflows from solar generation on the distribution grid on substations in its North Carolina service territory.

16. Overall DENC is not likely to see any line loss avoidance from these QFs going forward as recent trends indicate that backflows on DENC's system will increase, not decrease, in the future.

17. Qualifying Facilities that add battery storage to their facilities should receive current rates for the output of their batteries and output from the original facility remains at the previously contracted rates.

18. It is appropriate that the Utilities, the Public Staff, and other interested stakeholders engage in a working group to address the technical and commercial issues related to battery storage before the next biennial avoided cost proceeding.

19. The rate schedules and standard contract terms and conditions proposed in this proceeding by DENC should be approved, except as otherwise discussed herein. DENC should be required to file new versions of its rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to

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become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 150-day period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1-2

Summary of the Evidence

In the 2016 Order, the Commission found it appropriate to require the Utilities to make the standard offer contract available to all QFs with a generation capacity of up to 1 MW. As to those QFs that are "small power producers," as defined in G.S. 62-2(27a), the Commission concluded that G.S. 62-156 resolved that issue. As to those QFs that are cogeneration facilities, the Commission concluded that the evidence demonstrated that this reduction would promote PURPA's goal of making the Utilities indifferent to whether the energy or capacity purchased is supplied by a QF, through self-build, or otherwise, by increasing the number of QF projects that will negotiate contracts. The Commission concluded that the changes in the standard offer term and eligibility threshold contained in G.S. 62-156, viewed jointly with the other changes being adopted by the Commission, reflected 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. It noted that one part of this effort was the Commission's implementation of the General Assembly's directives enacted in North Carolina Session Law 2017-192 (House Bill 589). The Commission stated 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

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exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to obtain financing on reasonable terms. (2016 Order at 37-38.)

The Commission also ruled in the 2016 Order, as in past biennial avoided cost proceedings, 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. The Commission stated that such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. (2016 Order at 38.)

Discussion and Conclusions

No party to this proceeding presented evidence or proposals to change the Commission's conclusions on these matters in this proceeding. No evidence was presented to contradict the Commission's conclusion in the 2016 Order that the 1 MW eligibility threshold for the standard offer will promote PURPA's goal of making the Utilities indifferent to whether the energy or capacity purchased is supplied by a QF, through self-build, or otherwise. Based on the foregoing and the entire record in this proceeding, the Commission therefore finds that it continues to be appropriate to require the Utilities to offer as a standard option long-term levelized capacity payments and energy rates for ten-year periods to all QFs contracting to sell one MW or less capacity.

The Commission also concludes consistent with previous biennial orders 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

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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 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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3-5

The evidence supporting these findings of fact is found in the Initial Statement of DENC; the Initial Comments of the Public Staff, NCSEA, and SACE; the Reply Comments of DENC, the Public Staff, and NCSEA; and the testimony of DENC witness Petrie, Public Staff witness Thomas, and NCSEA witness Johnson.

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Summary of the Evidence

In the 2016 Order, the Commission held that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities," and required the Utilities to consider refinements to the avoided capacity calculation and to address these refinements in this proceeding. (*2016 Order,* at 56.) The Commission specifically ordered that the Companies should consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." (*Id.*) The Scheduling Order similarly directed the Companies to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules." (*Scheduling Order,* at 1-2.)

In response to the Commission's directives, with its Initial Statement DENC proposed changes to the rate schedules for both energy and capacity that offer additional granularity and improved price signals to QFs to better match DENC's generation needs. DENC proposed a revised rate structure that included seasonal capacity rates and non-seasonal on and off-peak energy rates. (DENC Initial Statement at 29.)

With regard to capacity rates, DENC based its proposed capacity peak hours on the hours when system peak loads historically have occurred, and when system emergencies are most likely to occur. DENC proposed to allocate capacity costs 50% to the summer season, 40% to the winter season, and 10% to the shoulder season, maintaining a slightly higher cost allocation to the summer months due to the Company's

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participation in PJM, which is a summer peaking system. (DENC Initial Statement at 30-31.)

Consistent with its comments regarding Duke's proposed rate design changes, the Public Staff in its Initial Comments stated that the pricing periods proposed in this proceeding are an improvement over the current Option B hours in terms of being reflective of historical marginal energy costs. Nevertheless, the Public Staff believed that energy rate mismatches were still likely that could result in QFs potentially being over- or under-paid for the energy generated. (Public Staff Initial Comments at 47-48.) As a result, the Public Staff proposed its own seasonal energy rates and hours.

Regarding DENC's proposed seasonal allocation of capacity payment costs and its selection of Capacity Peak Hours, the Public Staff found them to be reasonable, but stated that the reliance on the broader characteristics of the PJM region results in a misalignment of DENC's system with the seasonal allocation and Capacity Peak Hour, and recommended that DENC evaluate alternative seasonal allocation and Capacity Payment Hours that align more directly to its system (as opposed to the PJM system as a whole, which has different capacity needs from a utility operating in North Carolina). (*Id.* at 60, 64.)

NCSEA also stated that the utilities did not adequately recognize how costs vary across different times of day. NCSEA proposed that instead of the utilities' proposals, the Commission should adopt the time-of-day periods it proposed, as well as an optional, real-time pricing tariff for QFs. (NCSEA Initial Comments at 28.)

In its Reply Comments, DENC responded to NCSEA's proposal to incorporate geographic price signals that provide an economic incentive for QFs to locate in areas

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that are most advantageous to the grid, by noting that a QF may choose to sell its power under the Schedule 19-LMP tariff, which is locational in nature and has hourly granularity in its market-based prices. (DENC Reply Comments at 25.)

DENC further stated that it continues to believe that its original proposed energy seasons and peak hours designations are reasonable and appropriate, particularly for the purposes of the standard offer. It also stated that in subsequent discussions with the Public Staff on this issue, the Public Staff has recognized that September is appropriately included in DENC's summer peak season. In addition, DENC noted that in those discussions the Public Staff has proposed expanding the "premium peak" summer and winter hours such that there are four premium peak summer hours in the afternoon and four premium peak winter hours, two in the morning and two in the evening. As a result of these discussions, DENC indicated that it would be willing to accept the Public Staff's proposal, as modified, in the interest of achieving consensus on this issue. DENC noted that its initial proposal included the afternoon hours on weekdays and weekends in the Energy Peak Hours, but under the modified proposal, it will pay on-peak and premium peak avoided energy rates on weekdays only. (*Id.* at 22-24.) With regard to capacity, DENC stated it would be willing to use a 45/40/15 seasonal allocation of CT costs, which would 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 season for capacity. (*Id.* at 37.)

NCSEA witness Johnson testified in favor of real-time pricing during "extreme conditions." He acknowledged the utilities' reply comments on this topic, and agreed that the utilities raised practical considerations that needed to be considered, but asserted that

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Sep 04 2019

those considerations do not justify rejection of his proposal. He further stated that DENC's LMP tariff is not as good a solution as NCSEA's proposal because of its linkages to volatile natural gas and other energy markets, and instead recommended that the utilities submit proposed real time pricing rates consistent with NCSEA's proposal at least six months before the next biennial proceeding. (Tr. Vol. 6 at 231-236.)

Public Staff witness Thomas testified that the Public Staff agrees with DENC's proposed rate design modifications, which include; (i) the inclusion of September as a summer month; and (ii) the expansion of the premium peak hours to encompass four hours in the summer and four hours in the winter (two in the morning and two in the evening). He further noted that while the rate design proposals for DENC and Duke agreed to by the Public Staff were nearly identical, the Public Staff supported continued consideration of the unique characteristics for each utility in rate design. At the hearing, witness Thomas confirmed that the Public Staff agrees in principal with the energy and capacity rate design presented in DENC witness Petrie's rebuttal testimony. (Tr. Vol. 6 at 394; Tr. Vol. 7 at 100.)

DENC witness Petrie testified that NCSEA witness Johnson's proposal to implement real-time pricing "essentially asks for both long term fixed prices and short term variable prices." He noted that QFs cannot, however, have it both ways. He testified that witness Johnson's proposal would effectively result in "higher-of" pricing, that is, the higher of the known FP rates and the potentially volatile LMP rates for a certain number of hours during the year. Witness Petrie testified that DENC believes this type of hybrid pricing is not reasonable because it is unfair to customers both for the optionality

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benefits provided to QFs at the expense of customers, as well as for administrative complexity. (Tr. Vol. 5 at 47-48.)

Discussion and Conclusions

Based on the evidence in this proceeding, the Commission finds that the revised rate design changes proposed by DENC and agreed to by the Public Staff are responsive to the Commission's directives in the 2016 Order and the Scheduling Order, and provide QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. DENC should therefore file updated rate schedules consistent with the energy and capacity rate design described in DENC witness Petrie's rebuttal testimony.

With regard to NCSEA witness Johnson's recommendation that DENC provide a hybrid rate that includes some real-time pricing components, the Commission agrees that real-time pricing rates for QFs could better align the utilities' avoided cost rates to QF payments, but recognizes that such an option must be balanced with the Utilities' obligations under PURPA to provide a QF with the option to commit to deliver its power at the utility's avoided cost either calculated at the time of delivery or calculated at the time the QF makes its legally enforceable commitment to deliver energy and capacity. The Commission notes that DENC continues to make available its Schedule 19-LMP rates for QFs, as well as offer standard, fixed rate contracts under Schedule 19-FP. The Commission finds that it is appropriate for DENC to continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Methodology, rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's last biennial proceeding.

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Sep 04 2019

The Commission also finds that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are 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 for capacity, and should be used in calculating DENC's avoided capacity rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding is contained in the Initial Statements and reply comments of DENC, the Public Staff, NCSEA, and SACE, the affidavit of NCSEA witness Beach, and the entire record in this proceeding.

Summary of the Evidence

DENC's Initial Statement described the methodology used to calculate avoided energy cost rates under its proposed Schedule 19-FP. DENC stated that it used the PROMOD production cost model to derive avoided energy cost rates 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, as discussed further below in Findings of Fact Nos. 7-8, a re-dispatch charge. (DENC Initial Statement at 7.) DENC stated that it uses the PROMOD output results to calculate the levelized on-peak and off-peak long-term fixed energy rates under Schedule 19-FP. (*Id.* at 8.)

Regarding forward commodity prices, DENC stated that consistent with past practice it developed its avoided energy cost rates using 18 months of forward market prices, 18 months of blended prices, and then ICF International prices exclusively starting

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Sep 04 2019

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Sep 04 2019

in month 37 of the forecast period. DENC noted that the Commission found this approach to be reasonable in the 2016 Case. (*Id.* at 8-9.)

DENC also explained that consistent with the Commission's conclusions on the 2016 Order, it adjusted the avoided energy cost rates proposed in this proceeding to reflect the fact that LMPs in the North Carolina area of its service territory continue to be lower than the LMPs for the DOM Zone. DENC provided updated data showing the continued disparity in LMPs, and stated that it included the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy rates. (*Id.* at 9-11.)

DENC also noted that in the Phase I Order of the 2014 avoided cost case (Docket No. E-100, Sub 140, Dec. 31, 2014) (Order on Inputs), the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC explained that in the December 17, 2015, Phase II Order of that proceeding (Phase II 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 Case, DENC proposed to continue to use the same Black-Scholes option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 avoided cost case, with a resulting fuel price hedging value of $0.30/MWh, which was assumed constant for all years of the Schedule 19-FP contract. (*Id.* at 11.)

In its Initial Statement, the Public Staff confirmed that DENC used the same method for calculating its avoided energy costs for Schedule 19-FP as it did in the 2016 Case and stated that it reviewed DENC's PROMOD inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs. (Public Staff Initial Statement at 19.) The Public Staff did not raise any concerns with DENC's forecasted natural gas prices. The Public Staff also stated that DENC's calculation of the fuel hedge value is reasonable. (*Id.* at 28.)

In its Initial Statement, NCSEA stated that QFs displace natural gas-fired generation, decrease exposure to volatility in natural gas prices, and provide a long-term physical hedge for the term of the PPA. NCSEA contended that renewable generation provides a hedge not otherwise available in financial markets. NCSEA asserted that the Black-Scholes Model assumes displaced gas is re-priced at the prevailing market price 5 or 10 times over a 10-year period, which does not provide as effective a hedge as the hedge actually provided by a 10 year PPA. NCSEA cited studies performed in 2013 for Xcel Energy's Public Service of Colorado, which arrived at a $6.60/MWh hedge benefit of distributed solar (Xcel Study) and to the 2015 Maine Public Utilities Commission's Distributed Solar Valuation Study (Maine Study). NCSEA used the Maine Study's method to calculate a 10-year hedging benefit of renewable PPAs in North Carolina using NCSEA's proposed gas forecast, current U.S. Treasury yields as the risk-free investments, the Utilities' weighted average costs of capital, and a marginal heat rate of 7,250 Btu/kWh. With this method, NCSEA calculated an avoided fuel hedging cost of about $0.007/kWh. (NCSEA Initial Statement at 21-23.) In his affidavit attached to NCSEA's Initial Statement, witness Beach reiterated that renewable QF generation provides a long-term physical hedge to natural gas prices and argued that the natural gas hedging costs used in the avoided cost rates in the past are too low because they only represent the cost to fix gas prices for 1 or 2 years rather than the 10-year hedge provided

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by renewable QF PPAs. Witness Beach also supported the Maine Study's method to calculate hedging costs. (Beach Affidavit at 4.)

NCSEA asserted that a balanced fundamentals forecast should be based on (1) the ICF forecast utilized by DENC and (2) the new 2019 forecast from the Energy Information Agency (EIA). In the alternative, NCSEA stated that it "would not object to the use of DENC's similar forecast methodology" of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities. (NCSEA Initial Statement at 19.) In his affidavit, witness Beach expressed support for a forecasting approach similar to that of DENC, using forward market prices as the forecast for no more than the first two years and then transitioning to the average of a set of fundamental forecasts by year five and using fundamentals forecasts from several sources to avoid over-reliance on one approach. (Beach Affidavit at 3-4.)

In its reply comments, SACE did not specifically critique DENC's calculated hedge value and acknowledged that the Black-Scholes model is an industry-accepted methodology for calculating fuel hedging costs, but advocated "to the extent Utilities are able" a methodology such as that used in the Maine Study. (SACE Reply Comments at 4-5.)

No party objected to DENC's continued application of the LMP adjustment to its avoided energy rates.

In its reply comments, DENC stated that the 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 and that DENC believes the method remains appropriate. In particular, DENC noted that ICF forecasts are reputable and respected in

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Sep 04 2019

the industry and the EIA forecast recommended by NCSEA does not provide tailored forward pricing for the mid-Atlantic region in which DENC operates, as do the ICF forecasts. (DENC Reply Comments at 4-5.)

With regard to hedging, DENC explained that the Black-Scholes option pricing method to determine fuel hedging benefits was thoroughly reviewed and proposed by the Public Staff in the 2014 avoided cost proceeding. In response to NCSEA and witness Beach's recommendation that the value of hedging should be calculated based on the cost of executing hedges over the full 10 year PPA horizon, DENC referenced the Commission's finding in the Phase II Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities which, in DENC's case, is approximately 18 to 24 months in the future. DENC explained that the Xcel Study is inappropriate for use in this proceeding because the results for the study are inflated as it looked 20 years into the future using relatively stale high gas prices. DENC explained further that when the Xcel Study was conducted in 2013, the forecasted natural gas price for 2025 was approximately $7.50/mmbtu, while the current forecasted price for 2025 is $4.00mmbtu. DENC also noted that it is not clear if the Xcel Study used the cost of call options to determine the hedge value and that it appears instead to be a cash flow discounting exercise that does not accurately represent the value of reduced natural gas pricing volatility in the future. DENC noted in addition that the Maine Study is similarly relatively outdated, its authors noted difficulties with the method and how it required "some simplifying assumptions," and it does not include the possibility of future downward movements in natural gas prices, which leads to unreasonably high energy rates paid to QFs. (*Id.* at 6-8.)

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Sep 04 2019

In its reply comments, the Public Staff stated that in the Order on Inputs, the Commission found that renewable generation provides fuel price hedging benefits and these benefits should be valued over terms that are comparable to the utility's hedging terms. The Public Staff also noted that, in compliance with the Commission's directive from that Order, DENC included the avoided fuel hedging values in its avoided energy calculations. The Public Staff disagreed with witness Beach's recommendation that the benefit of the hedge should be calculated to approximate the hedge value over a ten-year term because the Utilities rely on hedge terms that are significantly shorter. The Public Staff stated that the value of the hedge should be calculated over a term comparable to the utility's "actual natural gas hedge contracts that can be avoided, as proposed by DENC." (Public Staff Reply Comments at 8.)

Discussion and Conclusions

Based on the record in this proceeding, the Commission concludes that the inputs DENC used to model its estimated avoided energy costs are reasonable and are approved.

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 avoided cost proceeding, continues to be appropriate. No party raised specific objections to DENC's approach, and we decline to require DENC to adopt witness Beach's proposed method for the reasons discussed in DENC's reply comments.

With regard to hedging, in the Order on Inputs, 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

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Sep 04 2019

calculating avoided energy costs. (Order on Inputs at 8, 42) In the Phase II Order, we 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. (Phase II Order at 7, 30-31) Based on the record in this proceeding, the Commission finds that the Black-Scholes Model or a similar method continues to be appropriate to reflect hedging benefits in avoided cost rates. We therefore conclude that DENC has appropriately calculated avoided hedging costs using the Black-Scholes model, and accept as reasonable and appropriate for this proceeding DENC's proposed hedging value of $0.30/MWh, which it assumed constant for all years of the Schedule 19-FP contract. We decline to accept witness Beach's recommendation that the benefit of the hedge should be calculated to approximate the hedge value over a ten-year term. We continue to find as the Commission did in the Phase II Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities, and DENC relies on a 18-24 month hedge term. The Commission also concludes that because we continue to find the Black-Scholes or a similar method to be a reasonable way to calculate hedge value, and based on the reasons explained by DENC, the Xcel and Maine Studies are not appropriate for use in determining avoided hedging values for avoided cost rates in North Carolina.

Finally, based on the evidence presented by DENC updating the continued disparity in LMPs in its service territory, which no party contradicted, the Commission finds that it continues to be appropriate for DENC to include the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy rates for purposes of this proceeding.

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Sep 04 2019

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 7-8

The evidence supporting this finding is contained in the Initial Statements and initial and reply comments of DENC, the Public Staff, NCSEA, and SACE and in the testimony of DENC witness Petrie, Public Staff witness Thomas, NCSEA witnesses Beach and Johnson, and SACE witness Kirby, and the entire record in this proceeding.

Summary of the Evidence

In the 2016 Order, the Commission concluded that "it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity." (2016 Order at 98) The Commission directed that with their initial filings in this proceeding the Utilities address, among other issues, "consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable." (2016 Order at 110-111.) The 2018 Procedural Order in this proceeding reiterated that directive.

In its Initial Statement, DENC recognized these directives and noted that the addition of new QF generation can have an impact in two distinct areas: ancillary services and integration costs. DENC proposed to adjust the avoided energy cost payments to new QFs to reflect the increase in system supply costs—specifically called "re-dispatch" costs—caused by these generators. DENC defined re-dispatch costs as the additional fuel and purchased energy costs incurred due to the unpredictability of events that occur during a typical power system operational day. It explained that as more and more intermittent generation such as solar or wind is added to the grid, the level of uncertainty regarding re-dispatch costs increases due to the unpredictable output of these types of units, caused by changes in cloud cover or changes in wind speed. DENC clarified that it was not proposing to adjust avoided cost rates to specifically account for the potential costs or benefits related to changes in ancillary services requirements that occur due to increased levels of new QF generation on the system. (DENC Initial Statement at 12-13.)

To calculate the re-dispatch cost, DENC explained that in conjunction with the development of its 2018 IRP, it performed a simulation analysis to determine the cost impact on generation operations. It used hourly generation data from 26 solar sites located within its service area and currently interconnected to its system to develop generation profiles for these facilities. DENC performed the study at three levels of solar photovoltaic (PV) penetration to provide a range of results. It used the PLEXOS model to determine an overall system cost impact, which it calculated to be approximately $1.78/MWh. DENC proposed to adjust avoided energy payments made to QFs under Schedule 19-FP by that amount. (*Id.* at 13.)

In its initial statement, the Public Staff did not oppose the concept of a re-dispatch charge, but made a number of recommendations and raised certain concerns. First, the Public Staff argued that the avoided energy rate should not be reduced by separately calculated charges, and stated that a consolidated charge would present difficulties for tracking costs of compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The Public Staff recommended that DENC collect and administer the re-dispatch costs separately from the avoided energy rate, similar to Duke's approach for the SISC. Second, while the Public Staff agreed that it was reasonable to calculate the re-

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Sep 04 2019

dispatch charge using solar resource data, as solar is the dominant type of intermittent, non-dispatchable QF, it suggested that in the future DENC separately calculate the charge specific to each type of intermittent, non-dispatchable QF seeking to interconnect to its system. (Public Staff Initial Statement at 30-32, 43-46.)

As for its concerns, the Public Staff stated that DENC's calculation of the charge, which reflected equal weighting of multiple cost categories and solar penetration scenarios, may not be reasonable. More generally, the Public Staff noted the Commission's conclusions in the Order on Inputs that inclusion of costs and benefits related to solar integration in the Utilities' avoided cost calculations would be "appropriate only when both costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained." (*Id.* at 32, quoting Order on Inputs at 60-61.) The Public Staff acknowledged that some costs of QF energy and capacity are less discernable than others, and stated that it may be appropriate for the Commission to consider evidence from other parties regarding what additional costs or benefits can be sufficiently known and verifiable such that they should be included in avoided cost rates. (*Id.* at 32-33.)

In its initial statement, NCSEA asserted as it did with respect to Duke's SISC that the re-dispatch charge is inconsistent with previous Commission decisions and does not comply with PURPA. NCSEA pointed to the Commission's recognition in the Order on Inputs that it may be appropriate to reflect the costs and benefits of integrating solar resources into the Utilities' avoided cost calculations. (NCSEA Initial Statement at 32-33.) NCSEA contended that DENC's proposed re-dispatch charge failed to comply with the 2016 Order, since the charge did not take the form of a separate rate schedule.

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Sep 04 2019

NCSEA also asserted that the proposal is inappropriately based on generation technology rather than QF characteristics, and that DENC admitted such noncompliance in its initial statement. NCSEA also argued that the re-dispatch charge (and Duke's SISC) represents single-issue ratemaking because it is a "rate" under G.S. 62-3(24) and should be set during a general rate case. NCSEA argued further that the charge is not a "rate" under 18 C.F.R. § 292.101(b)(5) because it does not involve the sale or purchase of electric energy or capacity, and that even if it is a rate under FERC rules it is not appropriate under 18 C.F.R. § 292.304(e). (*Id.* at 34-35, 47-48.) NCSEA also claimed that the Utilities failed to accurately capture the effect that wind and solar resources have on market prices by reducing demand on regional markets for electricity and natural gas and thereby reducing market prices. (*Id.* at 43-45.)

In an affidavit attached to NCSEA's Initial Statement, witness Johnson stated that refining avoided cost rates to consider the costs and benefits associated with integrating solar resources is "not objectionable, per se," but took issue with how the Utilities conducted their respective analyses. He claimed, among other things, that the Utilities failed to take an unbiased approach, only considered negative impacts imposed by solar QFs, and ignored the geographic diversity of solar QFs that avoids transmission and distribution (T&D) costs. With regard to DENC's re-dispatch charge, in contrast to NCSEA's own position he did not oppose the concept of a re-dispatch charge itself, acknowledging that "[i]t is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy." (Johnson Affadavit at 17-18.) He asserted however that the proposed $1.78/MWh is too high because DENC (1)

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Sep 04 2019

only partly considered the benefits of geographic diversity by only relying on 26 individual sites for its analysis, and (2) improperly weighted the average of multiple cost and solar penetration scenarios. He presented his own calculation of a re-dispatch charge of $0.69/MWh, which appeared to be based on removal of the PJM and generation-only cost categories of DENC's re-dispatch analysis and the 80-MW solar penetration scenario. (*Id.* at 18-20.)

In another affidavit attached to NCSEA's Initial Statement, witness Beach similarly claimed that the re-dispatch charge did not consider the benefits of integrating QF resources into the system. Witness Beach also asserted that appropriately-located QFs will allow T&D costs to be avoided, citing an example using *Duke's* distribution substations to show how avoided T&D costs can be allocated to hours of the year using peak capacity allocation factors. Witness Beach also asserted a potential market suppression benefit of integrating QF power and recommended that the Commission direct the Utilities to study the ability of their T&D system to host distributed generation and storage resources. (Beach Affidavit at 6-7.)

In its Initial Statement, SACE disagreed with DENC's methodology for determining the re-dispatch charge for several reasons, including using the 80 MW solar penetration level and averaging the results of the analysis. Based on these alleged methodological flaws, SACE concluded that DENC failed to adequately support its re-dispatch charge and that the Commission should therefore reject it. (SACE Initial Statement at 17-18.)

In its Reply Comments, DENC reiterated the basis for its re-dispatch proposal and explained in addition that applying the re-dispatch charge will help ensure that its

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Sep 04 2019

customers pay for accurate avoided costs, since without the charge customers would overpay for QF output. DENC explained that in the analysis providing the basis for the proposed charge, it gave equal weight to each of the cost categories considered, which included all costs, PJM purchases/sales, pumped storage costs/revenues, and generator costs only. DENC stated that it chose solar penetration levels of 80 MW, 2,000 MW, and 4,000 MW for the analysis, and described the process it used to calculate the charge based on those levels. (DENC Reply Comments at 8-11.)

DENC stated that while it proposed to apply the re-dispatch charge as a reduction to the avoided energy rate for purposes of administrative efficiency, if the Commission agrees with the Public Staff that it should be separated from the avoided energy rate, DENC could modify the administration of the charge to occur as a separate line item on a QF invoice. DENC also stated that it is willing to evaluate the potential for calculating separate re-dispatch charges for other generation types in future cases. (*Id.* at 9-10.)

DENC explained that it had discussed its proposal with the Public Staff and had addressed a number of the Public Staff's questions and concerns. DENC also stated that in those discussions, the Public Staff recommended re-calculating the re-dispatch charge without considering an 80 MW solar penetration level, and allocating 70% to the 2,000 MW scenario and 30% to the 4,000 MW scenario. DENC described these points as representing Public Staff's remaining concerns with the re-dispatch proposal. DENC stated that it continued to believe that the approach it took in the simulation analysis with respect to cost category and solar penetration level selection and weighting to be reasonable, and provided arguments in support of those aspects of its original approach to calculating the charge. DENC explained that it believed it was appropriate to weight

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Sep 04 2019

each category equally, since each plays a major role in the total re-dispatch cost related to distributed solar generation. DENC also explained the rationale for including each of the solar penetration levels and for weighting each level equally in the charge calculation. DENC concluded, however, that in the interest of reaching compromise on the issue and narrowing down the areas of dispute, it was willing to recalculate the re-dispatch charge for purposes of this proceeding with modified cost category and solar penetration scenario weightings, resulting in a re-dispatch charge of $0.78/MWh. (*Id.* at 12-14.)

In response to NCSEA, DENC first clarified that its presentation of the re-dispatch proposal did not constitute an admission of noncompliance with the 2016 Order, but rather made clear that the proposal was intended to quantify the added costs due to re-dispatching of units caused by the intermittency of solar QF output, and not to specifically account for potential costs or benefits related to changes in ancillary service requirements. DENC also stated that in preparing the Initial Filing and developing the re-dispatch charge proposal, it carefully evaluated the Commission's directives in the 2016 Order. DENC acknowledged the Commission's directive for the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity. DENC explained that in developing its proposal, DENC determined that it would be more efficient, and therefore benefit both the QF and DENC, to include the re-dispatch proposal in the existing rate schedule rather than to propose a separate rate schedule only for intermittent QFs. DENC stated its belief that QF developers are generally sophisticated entities that can determine which parts of a standard avoided cost tariff apply to them. DENC also noted, however, that it will

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Sep 04 2019

comply with any Commission determination that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule. (*Id.* at 15-17.)

DENC next explained that the charge was derived based on data associated with the intermittent, non-dispatchable QFs in its service area, all of which at this point in time are in fact solar QFs. DENC noted that, while the proposed charge is actually "based upon a consideration of the characteristics of the power supplied by" these QFs (those characteristics being intermittency and unreliability), for purposes of North Carolina, where almost all intermittent non-dispatchable QF generation is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." DENC concluded that, practically, these terms present a distinction without a difference. DENC noted its willingness to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, non-dispatchable QFs in a future proceeding. (*Id.* at 17.)

DENC also addressed NCSEA's contention that the re-dispatch charge is a "rate" under G.S. 62-3(24) that should be set during general rate cases pursuant to G.S. 62-133, and that it is not a "rate" under FERC rules implementing PURPA because it does not involve the sale or purchase of electric energy or capacity. As to the former, DENC showed that the re-dispatch charge is not a "rate" as that term is contemplated by Section 62-3(24), which contemplates charges for services or commodities offered by the utility to the public, as the charge is not so related, but instead reflects the impact to DENC's system of intermittent, non-dispatchable QFs from which DENC is required by law to purchase energy. DENC also explained that taken to its logical end, NCSEA's argument would nullify G.S. 62-156. As to the latter, DENC noted that the charge is valid

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Sep 04 2019

regardless of whether it qualifies as a "rate" under 18 C.F.R. § 202.101(b)(5), and explained that it is also consistent with the Section 202.304(e) because it properly considered the enumerated factors listed in the FERC regulations. (*Id.* at 17-19.)

DENC also addressed NCSEA's and witness Johnson's contentions regarding costs and benefits. In particular, due to their intermittent nature and concentration in its small North Carolina service territory, DENC stated that non-dispatchable QFs do not allow DENC to avoid T&D costs and that due to the potential for additional line losses resulting from backfeeding, the opposite is more likely true. DENC further addressed costs and benefits in witness Petrie's testimony as discussed below. (*Id.* at 19-21.)

In response to SACE, DENC stated that its willingness to recalculate the re-dispatch charge consistent with the Public Staff's recommendations should address SACE's concerns with the proposal. (*Id.* at 21-22.)

In its reply comments, the Public Staff presented a summary of DENC's proposed charge and stated that it was not convinced that DENC considered the appropriate cost and solar scenarios in its re-dispatch charge calculation. The Public Staff disagreed with the "no PJM," "no pumped storage," and "generator cost only" scenarios based on its belief that those categories do not represent DENC's current operations. The Public Staff stated that DENC is a part of PJM, and also has access to energy and capacity from the Bath County pumped storage facility in Virginia. It stated that while these scenarios may be illustrative of the impact solar "might" have on system costs were DENC to leave PJM or decommission its pumped storage facility, they are not appropriate for use in specifying a charge to apply to non-dispatchable QFs today. The Public Staff noted that the higher re-dispatch charge associated with a "No PJM" scenario indicates the value of

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Sep 04 2019

being able sell excess energy into the PJM market. The Public Staff also found the 80 MW solar penetration scenario to be inappropriate because DENC already has several hundred MW of solar capacity installed. It stated that the 2,000 MW is more likely in the future due to the higher probability that DENC's total system will realize this level of intermittent capacity, and that the 4,000 MW scenario might be achieved in the more distant future due to Virginia's mandate of increased deployment of solar resources through the Grid Transformation and Security Act of 2018. To address these concerns, the Public Staff proposed that DENC give 100% weight to the all costs category and no weight to the other cost categories, and give 70% weight to the 2,000 MW solar penetration scenario, 30% weight to the 4,000 MW scenario, and none to the 80 MW scenario. The Public Staff also noted that the re-dispatch charge and Duke's proposed SISC may result in recovery of overlapping costs and stated that to the extent the Commission approves the broader application of these calculations in future proceedings, it is appropriate for the costs to be fully delineated to reduce any overlap. (Public Staff Reply Comments at 20-23.)

In its reply comments, NCSEA agreed with SACE's position that DENC inappropriately averaged costs associated with multiple solar penetration levels and combinations of assumptions, which resulted in an inflated charge. NCSEA also echoed some of the questions raised by the Public Staff in its initial comments. NCSEA stated its opposition to any fixed charge that "allegedly" offsets costs to the grid due to intermittent QFs, reiterating its position that distributed generation, including solar, causes a net benefit to the grid and rate payers. (NCSEA Reply Comments at 17-18.)

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Sep 04 2019

In its reply comments, SACE contended that the Utilities failed to analyze the potential benefits of solar integration and therefore did not comply with the Commission's previous orders. SACE also agreed with NCSEA that QFs should be compensated for the full range of costs they allow the purchasing utility to avoid, including applicable T&D costs. SACE recognized the Public Staff's concerns regarding an integration charge's potential impact on REPS and other programs' administration if the charge is embedded in the avoided cost rate, but ultimately supported DENC's approach of applying the re-dispatch charge, if approved, as a decrement rather than as a stand-alone charge. SACE suggested that the Commission could establish a procedure to remove any integration charge in the administration of the applicable REPS or other program, to address this concern. (SACE Reply Comments at 13-16.)

In his direct testimony, DENC witness Petrie stated that in the 2016 Order and the 2018 Procedural Order, the Commission found merit in the concept that evaluation of the Utilities' avoided costs should consider factors such as a QF's capacity, dispatchability and reliability, and the value of QF energy and capacity in establishing avoided cost rates. Witness Petrie reiterated DENC's explanation of the meaning of re-dispatch costs and description of its calculation of the re-dispatch charge. He clarified that DENC's proposal to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP by $1.78/MWh applied to both standard offer QFs and larger QFs with negotiated PPAs. He also clarified that while the re-dispatch charge is complementary to Duke's proposed SISC, the charges are not the same, as DENC and Duke each analyzed a different aspect of the impact of resource intermittency on their respective systems. (Tr. Vol. 5 at 15-18.)

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Witness Petrie noted that the Public Staff did not disagree with the re-dispatch charge in theory and responded to several of the Public Staff's concerns and recommendations consistently with DENC's reply comments. First, witness Petrie stated that if the Commission agreed that the re-dispatch charge should be separated from the avoided cost payment, DENC can modify the administration of the re-dispatch charge to appear as a separate line item on a QF's invoice. He also testified that DENC is willing to evaluate the potential for separately calculating re-dispatch charges for other types of QF generation in future cases. Finally, he explained that since the filing of initial comments, DENC and the Public Staff discussed the re-dispatch proposal, including how the generation portfolios were constructed, how the 85 PLEXOS model runs were used, and other issues raised by the Public Staff and resolved most of the Public Staff's concerns. With respect to Public Staff's remaining concerns regarding the weighting of cost categories and selection of solar penetration weights, witness Petrie stated that while it believes its initial analysis was appropriate, in the interest of compromise, DENC was willing to re-calculate the re-dispatch charge with modified cost categories and solar penetration scenarios as recommended by Public Staff. Specifically, he clarified that DENC is willing to re-calculate its re-dispatch charge giving 100% weight to the "all cost" cost category, and 70% and 30% weight to the 2,000 and 4,000 MW solar penetration levels, respectively. Witness Petrie testified that these modifications resulted in a $0.78/MWh re-dispatch charge. (Tr. Vol. 5 at 19-22.)

Witness Petrie responded to NCSEA's contention that the re-dispatch charge failed to comply with the 2016 Order. He stated that the re-dispatch charge is compliant with the 2016 Order's statement to "consider and propose additional rate schedules"

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because DENC did consider proposing new rate schedules but determined that, in the interest of efficiency, the re-dispatch charge should be included in the existing rate schedule. He testified that if the Commission determines that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule, DENC will comply with that determination. With respect to NCSEA's assertions regarding the focus on generation technology, he stated that the re-dispatch charge is based on data associated with the intermittent, non-dispatchable QFs in DENC's service area, all of which are solar QFs. Therefore, he explained, there is an inherent overlap between the concepts of "generation technology" and "QF characteristics," and for DENC's purposes those terms present a distinction without a difference. (Tr. Vol. 5 at 22-24.)

Witness Petrie stated that NCSEA and SACE's concerns regarding the actual derivation of the re-dispatch charge should be addressed by DENC's willingness to recalculate the charge as recommended by the Public Staff. He also responded that DENC did account for both costs and benefits associated with distributed solar generation in its re-dispatch analysis as well as in the basic avoided energy rate. He testified that the macro benefits to new solar generation, including zero fuel cost for solar generation, displacement of DENC owned generation, and PJM purchases during daytime hours, and the related fuel price hedge benefit, were reflected in the production cost modeling and in the separate hedge value adder to the energy rates. He noted that DENC has not observed any benefits with respect to system dispatch and minute-to-minute operational control of the grid from the addition of intermittent resources, such as solar QFs, to its system that are not already accounted for in the avoided energy costs. (Tr. Vol. 5 at 24-25.)

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Witness Petrie also responded to witness Johnson's contentions regarding geographic diversity, explaining that the QFs evaluated for the re-dispatch analysis are in fact geographically dispersed throughout DENC's service area, including North Carolina. He explained further, however, that the North Carolina portion of that service area is relatively small, with very limited geographic diversity as compared to the rest of DENC's footprint. He noted that as a result, the intermittency of solar QFs located in North Carolina is not mitigated by their geographic diversity throughout DENC's service area. Witness Petrie also clarified that PJM market purchases and sales are accounted for in the re-dispatch study, as the PLEXOS model assumed DENC would sell excess power into PJM during the peak hours with higher LMP costs and make market purchased at low prices. In calculating the re-dispatch cost, he explained, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost. (Tr. Vol. 5 at 25-26.)

Witness Petrie concluded by noting that there are 72 solar QFs operating in DENC's North Carolina service area, representing approximately 501 MW of solar capacity, and that once all of the QFs with which DENC has executed power purchase agreements (PPAs) come online, that total will rise to 691 MW, which significantly exceeds DENC's 2018 average on-peak load of approximately 525 MW. He stated that DENC's proposed re-dispatch charge represents the first step in quantifying the costs of integrating these large volumes of solar PV generation onto its system, which was first addressed in the 2012 avoided cost case, Docket No. E-100, Sub 136. He stated that DENC will continue to work on this issue, but for purposes of this biennial period believes that the re-dispatch charge is fair to both QFs and DENC's retail electric

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customers, because it will provide energy payments to QFs that better reflect DENC's actual avoided energy costs. (Tr. Vol. 5 at 27-28.)

In his testimony, Public Staff witness Thomas described the re-dispatch charge as reflecting the deviations from the optimal dispatch order of DENC's fleet of dispatchable generation units due to fluctuations in the output of intermittent, non-dispatchable resources. He explained that similar to the changes in dispatch order caused by load certainty, the uncertainty of intermittent, non-dispatchable energy resources causes units to be dispatched out of the least cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs, which are passed on to ratepayers. He also noted that unlike the Duke method of calculating the SISC, DENC's method of calculation is not probabilistic and does not measure system reliability. (Tr. Vol. 6 at 373-374.)

Witness Thomas testified that the re-dispatch charge is a reasonable attempt to quantify the costs incurred by intermittent generators, but noted that the Public Staff had identified potential concerns with the charge as proposed. He noted the Public Staff's suggestion of an alternate set of weightings resulting in a re-dispatch charge of $0.78/MWh, which the Public Staff believes better reflects the DENC system and actual costs incurred. He argued that including cost scenarios such as the "no PJM" scenario would inappropriately exclude benefits provided by solar QFs due to DENC's membership in PJM. He acknowledged DENC's willingness to recalculate the charge with the Public Staff's recommended weightings. He recognized that the re-dispatch charge and Duke's SISC attempt to quantify different aspects of integrating intermittent

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generation and use different approaches, but based on the Public Staff's review of these proposals stated that there is likely some overlap between them. (Tr. Vol. 6 at 374-376.)

In their comments filed in this proceeding, the Public Staff and NCSEA discussed whether or not solar QFs with battery storage capability should be subject to Duke's proposed SISC. On May 21, 2019, Duke and the Public Staff filed a stipulation that, in part, would exempt QFs from the Duke SISC if they can operate the facility in a manner that "materially reduces the need for additional ancillary service requirements," as determined by Duke, to include battery storage, dispatchable contracts, or other mechanisms. In his testimony, Public Staff witness Thomas testified to the Public Staff's belief that certain technologies, such as energy storage, could if operated appropriately reduce or eliminate the intermittency of solar generator output, and recommended that to the extent a QF can materially demonstrate that it does not impose additional ancillary costs on the system, it should not be subject to the SISC or, "to a lesser extent," the re-dispatch charge. (Tr. Vol. 6 at 376-381.)

NCSEA witness Johnson did not offer testimony on the re-dispatch charge. NCSEA witness Beach testified generally on the re-dispatch charge together with the Duke SISC. Witness Beach recommended that the Commission not adopt either of these proposed charges, and asserted that any cost to integrate solar resources will be offset by benefits of these resources that he contended the Utilities have not recognized. In his testimony, SACE witness Kirby asserted a lack of detail supporting the re-dispatch charge calculations and contended that DENC did not include an analysis of the benefits of solar projects. He also, however, testified that DENC's agreement to remove the 80 MW solar penetration scenario from its analysis and to solely use the "all costs" category

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for its re-dispatch charge analysis instead of averaging all four of its originally proposed cost categories helped alleviate his concerns on these fronts. (Tr. Vol. 5 at 112, 208-210.)

In his rebuttal testimony, DENC witness Petrie testified that DENC remained willing to accept the Public Staff's recommended modifications to the re-dispatch charge calculation and resulting charge of $0.78/MWh for purposes of this proceeding. He noted that while NCSEA witness Beach generally recommended rejection of the re-dispatch charge, he did not offer any specific critiques of the charge itself. To the extent witness Beach's claims that the "utilities" did not properly consider and quantify the benefits of solar in presenting their proposed charges were made with respect to DENC, witness Petrie referenced his direct testimony and DENC's reply comments and testified that DENC has properly considered both costs and benefits in both the avoided cost rates and the re-dispatch charge. (Tr. Vol. 5 at 37-40.)

Witness Petrie also disagreed with any characterization of the charge as a "penalty." He explained that DENC's avoided energy costs are based on the difference in system production costs between a PROMOD model case without incremental QF energy deliveries and a case with a 100 MW flat block of zero-cost QF energy added to the system. He stated that because QFs do not deliver the same amount of energy every hour (i.e., they are intermittent and fuel limited), the rates derived from those model results should be adjusted to reflect the cost impact of the QF generation profile. He stated that the re-dispatch charge represents that adjustment, which improves the accuracy of the avoided energy rates and accounts for the way that the rates are calculated from the modeling results. With regard to SACE, witness Petrie reiterated that DENC did consider the benefits of solar facilities interconnected to its system, but noted

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that DENC's willingness to recalculate the re-dispatch appeared to mitigate witness Kirby's concerns. (Tr. Vol. 5 at 37-39.)

Finally, witness Petrie address the Public Staff's suggestion that to the extent a QF can materially demonstrate that it does not impose additionally ancillary services costs on the system, it should not be subject to re-dispatch charge. He explained that although the addition of battery storage may potentially smooth the QF's output during certain hours, the shape of the MW output during the middle of the day, in between charging in the morning and discharging in the evening, will still exhibit a considerable amount of volatility, which the redispatch charge would account for. He noted that DENC had yet to study the actual effect of a battery on output, which would need to be calculated to determine any appropriate discount to the re-dispatch charge. He therefore argued that the recalculated $0.78/MWh charge should apply to all solar QFs in this biennial period and be updated as appropriate in future proceedings based on further modeling to analyze the impact of new solar QFs co-locating battery storage at their facilities. (Tr. Vol. 5 at 40-42.)

At the hearing, NCSEA witnesses Johnson and Beach did not address the re-dispatch charge. In his summary of testimony, SACE witness Kirby recommended rejection of the re-dispatch charge until it is recalculated based on both the cost and benefits of integrating solar. DENC witness Petrie clarified in response to questions from counsel for SACE that in developing the re-dispatch charge, DENC focused only on re-dispatch costs and not ancillary services, and that he could not speak to whether Duke's SISC reflected some element of re-dispatch costs. He also clarified that DENC has no intention of double-counting re-dispatch costs, and that he expects DENC in the future to

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conduct a more comprehensive study that accounts for ancillary service costs. He also testified, and reiterated upon questioning by Commissioner Brown-Bland, that there are conceivable circumstances where it would be appropriate to not apply the re-dispatch charge to a QF that has installed battery storage. Witness Petrie also agreed in response to questions by counsel for the Public Staff that the re-dispatch charge could decline in the future. DENC witness Billingsley clarified in response to questions from SACE counsel that if approved the re-dispatch charge would apply prospectively only, including to QFs that renew their PPAs after the initial term has concluded. (Tr. Vol. 5 at 80-82, 92-94, 100-103, 215.)

Discussion and Conclusions

Based on the evidence presented, the Commission accepts DENC's proposed re-dispatch charge, as modified to be \$0.78/MWh, as reasonable and appropriate for purposes of this proceeding.

G.S. 62-156(b)(2) provides in relevant part that

> The rates paid by an electric public utility to a small power producer for energy shall not exceed, over the term of the purchase power contract, the incremental cost to the electric public utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source.

Section 292.304(e) of FERC's regulations implementing PURPA provides that

> in determining avoided costs, the following factors shall, to the extent practicable, be taken into account: … (2) the availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
> (i) The ability of the utility to dispatch the qualifying facility;
> (ii) The expected or demonstrated reliability of the qualifying facility;
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

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> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities[.]

In the 2016 Order, the Commission found merit in the concept reflected in testimony presented in that case that an evaluation of the Utilities' avoided costs should consider the characteristics of the power supplied by a QF. The Commission stated that considering the factors in G.S. 62-156 and the FERC regulations in the determination of avoided cost rates ensures that the Commission's avoided cost methodology remains true to PURPA's directive that avoided cost rates be based on the costs that the utility avoids. The Commission concluded that it would be appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power, if the Utilities' cost data demonstrates marked differences in the value of the energy and capacity provided by these QFs. The Commission also concluded:

> that it is appropriate to require the Utilities to calculate avoided energy and capacity costs for purposes of establishing rates available to QFs eligible for the standard offer without regard to the technology the QF uses to generate electricity. The Commission further finds that it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity.

2016 Order at 98. In Ordering Paragraph (16) of the 2016 Order, the Commission required that:

> in addition to their cost data and any other usual and appropriate matters, DEC, DEP, and DENC shall, in their initial filings in the Commission's next biennial proceeding established to determine avoided cost rates for electric utility purchases from QFs, address the following issues consistent with the discussion and conclusions in this order: … consideration of a

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Sep 04 2019

> rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable.

With this background in mind, the Commission has carefully considered all of the evidence presented on this issue. Notably, no party presented evidence to contradict that DENC is experiencing re-dispatch costs associated with the integration of intermittent, non-dispatchable QFs on its system. NCSEA witness Johnson specifically acknowledged that it is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, due to the variability of solar generation caused by cloud cover. With the exception of witness Johnson, NCSEA and SACE oppose the re-dispatch charge proposal, but do not present evidence to contradict it, particularly given DENC's agreement to recalculate the charge consistent with the Public Staff's recommendation. Given the evidence presented, the Commission concludes that the charge, modified as agreed to by DENC, should be accepted for purposes of this proceeding.

First, the Commission concludes that the re-dispatch charge complies with our previous orders and with PURPA and FERC's regulations. As directed in the 2016 Order DENC has proposed an adjustment to its rates to account for the characteristics of intermittent, non-dispatchable QFs. The Commission recognizes DENC's interest in administrative efficiency in incorporating the cost as a decrement to the avoided cost rates, but concludes that it is appropriate for this rate to be set out as a separate charge similar to the approach taken by Duke in order to account for the characteristics of intermittent, non-dispatchable QFs in avoided cost rates while not affecting the overall avoided cost rates that the Utilities apply more broadly in the context of other proceedings, including in the context of Renewable Energy and Energy Efficiency

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Portfolio Standard (REPS) cost recovery, fuel clause adjustment proceedings, and demand-side management/energy efficiency programs pursuant to G.S. 62-133.9.

The Commission also concludes that the re-dispatch charge does not constitute single-issue ratemaking or otherwise violate G.S. 62-156 or FERC's regulations. As DENC showed in its reply comments, NCSEA's arguments on this score are not consistent with the plain meaning of these statutory and regulatory provisions and taken to their logical end would result in a practical nullification of the North Carolina PURPA implementation statute, G.S. 62-156. That statute expressly requires that, every two years, the Commission determine the standard contract avoided cost rates to be included within the tariffs of each electric public utility and paid by electric public utilities for power purchased from small power producers. The Commission concludes it is appropriate to include the re-dispatch charge as a separate charge applicable to the avoided cost rates DENC must pay for purchases made under Schedule 19-FP to intermittent generating resources. With regard to FERC's regulations, whether or not the re-dispatch charge is a "rate" under 18 C.F.R. § 292.101(b)(5) is not relevant; the charge is essentially a part of the avoided cost rate – it is not presented as the "rate" itself.

The Commission also recognizes that the 2016 Order's directives specified that the proposed schedules be developed to reflect characteristics of intermittent generation and not be technology-specific. We are persuaded, however, that currently and for purposes of this proceeding, there is an inherent overlap and no real distinction between the concepts of "generation technology" and "QF characteristics," due to the fact that all of the intermittent non-dispatchable QFs in DENC's service area are in fact solar QFs.

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DENC has stated that it is willing to evaluate the potential for developing re-dispatch charges for other generation technologies in the future, and the Commission finds that this would be appropriate for DENC to do in the next avoided cost proceeding to the extent relevant data is available. As that data becomes available, it is possible that a real distinction will emerge. For purposes of this case, however, the Commission concludes that the re-dispatch charge appropriately accounts for the characteristics referenced by G.S. 62-156 and FERC's regulations and should be accepted. Specifically with regard to Section 292.304(e) of FERC's regulations, those rules provide that avoided cost rates should account for the availability of capacity or energy from a QF during the system daily and seasonal peak periods, "including" (but not limited to) several factors. NCSEA is reading too much into this regulation to argue that because re-dispatch costs (or ancillary services costs for that matter) are not expressly listed, they may not be considered as affecting the availability of a QF under this regulation.

The Commission is also not persuaded by the comments and testimony offered by NCSEA and SACE that DENC did not consider benefits as well as costs in developing the re-dispatch charge. We find DENC's filings and particularly witness Petrie's testimony convincing on this point. DENC has already reflected certain benefits of solar, including hedging value, in the underlying avoided energy cost rate. For purposes of the re-dispatch charge, DENC's calculation accounts for benefits associated with its membership in PJM, and DENC has not observed evidence of—and no party prsented evidence of—avoided T&D project costs on DENC's system from the growth of distributed solar. We therefore conclude that DENC's proposal is consistent with the Commission's discussion in the Order on Inputs that the integration of solar

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resources into a utility's generation mix results in both costs and benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculation. In addition and as noted by the Public Staff and NCSEA, in the 2014 avoided cost proceeding, the Commission found that

> while ultimately it may be appropriate for DEC, DEP and DNCP to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained.

Order on Inputs at 60-61. The re-dispatch charge does, as shown by DENC's testimony and other evidence presented, reflect benefits as well as costs. In contrast to intervenors who advocate for rejection of the re-dispatch charge without relevant evidence, DENC provided actual data supporting the charge based on solar generation located on its own system. Evidence presented relating to the New England ISO, for example, is not relevant to this proceeding. For the reasons stated above, we also decline to accept witness Beach's suggestion to direct the Utilities to study the ability of their T&D system to host distributed generation. Storage issues are addressed in the discussion for Finding of Fact Nos. 17-18 below.

In addition, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations, because without the charge, DENC's customers will overpay for QF power, as those payments will not reflect the costs to DENC to re-dispatch its system with large quantities of distributed solar generation interconnected to it. PURPA and FERC's rules provide that avoided cost rates be fair to utilities and QFs and that utilities should not pay more than avoided cost. The re-dispatch charge helps meet those requirements.

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With regard to DENC's approach to calculating the re-dispatch charge, the Commission concludes that the use the re-dispatch analysis from the 2018 IRP was reasonable and appropriate. The analysis was based on actual historical data from solar facilities existing on DENC's system, which was analyzed over 85 model runs in various scenarios to develop the charge. In sum, the Commission finds that DENC has made a substantial and well-supported effort to comply with the Commission's directive, which is augmented by DENC's willingness to re-calculate the charge consistent with the Public Staff's recommendations. The resulting $0.78/MWh charge is a full dollar less than the charge that DENC originally proposed, and very close to the $0.69/MWh charge that witness Johnson calculated as an illustrative alternative. DENC has indicated that the charge represents its first step in quantifying the costs of integration large volumes of solar PV generation onto its system, and that it will continue to evaluate these costs and benefits going forward. The calculation was made using the best information available at the time, but with further evaluation and refinements, as well as further changes in the development of QF projects, DENC acknowledged that it could decline in future proceedings. We therefore agree with witness Petrie that for purposes of this biennial period the re-dispatch charge is fair to both QFs and DENC's retail electric customers, because it will provide payments to QFs that better reflect DENC's actual avoided costs.

The Commission recognizes the discussions regarding a potential overlap between the costs being born by each utility that DENC's re-dispatch charge and Duke's SISC are intended to recover. In this proceeding, each utility has taken its own approach to evaluating and quantifying the costs to its system from intermittent non-

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Sep 04 2019

dispatchable QFs. Should DENC propose a revised charge or charges in the next biennial proceeding to address other costs to its system resulting from such QFs, the Commission will evaluate the reasonableness of such a charge at that time.

Finally, DENC acknowledged that there could be circumstances where a QF, due for example to the addition of a battery, could justify an exception from the re-dispatch charge, but also explained that the addition of a battery does not necessarily mean that re-dispatch costs are avoided. Given DENC's lack of experience with this issue to date, and the lack of clarity regarding the circumstances in which a QF could justify exemption from the charge due to addition of a battery, the Commission concludes that DENC should continue to evaluate this issue and update the charge as appropriate in future proceedings based on further modeling to analyze the impact of new solar QFs co-locating battery storage at their facilities.

In conclusion, DENC's proposed re-dispatch charge of $0.78/MWh is reasonable and appropriate for purposes of this proceeding and is accepted. In the filing of rate schedules that it makes in compliance with this order, DENC should reflect the modified re-dispatch charge of $0.78/MWh in its Schedule 19-FP.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting these findings of fact is found in the Initial Statement of DENC, the Initial Comments of the Public Staff and the affidavit of NCSEA witness Johnson, the Reply Comments of DENC, and the entire record in this proceeding.

Summary of the Evidence

In its Initial Statement, DENC proposed to apply annual capacity payment caps that reflect the characteristics of intermittent non-dispatchable resources. DENC noted

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the 2016 Order directive that the Utilities only offer avoided capacity payments in years in which the utility's IRP shows a need for capacity and that the Utilities should propose schedules demonstrating any "marked differences in the value of the energy and capacity provided by these QFs." (2016 Order at 98.) DENC explained that because solar and wind generation is intermittent in nature, the capacity benefit of these resources is not equivalent to the capacity benefit of a conventional CT unit. DENC provided data supporting the lower capacity value offered by solar and wind QFs on its system. Specifically, DENC presented data showing the hourly system loads of the DOM LSE on the peak day from the summer of 2018 overlaid with the aggregate output from DENC's solar non-utility generator (NUG) contracts. This data demonstrated that even under favorable sun conditions on a hot summer day, these units could not deliver output at their full nameplate capacity during the hours when the power was needed most, showing that they do not fully displace the operation of dispatchable CT units. DENC also presented data showing the hourly system loads of the DOM LSE on the peak day from the winter of 2017/18 overlaid with the aggregate output from DENC's solar NUG contracts. This data demonstrated that on a peak day in winter the capacity value of the solar facilities was nearly zero, again showing that these resources do not displace CT generation at the time of winter morning and evening peaks. (DENC Initial Statement at 20-21.)

Based on this data, DENC proposed an annual payment cap reflecting the capacity value of intermittent QFs relative to fully dispatchable CT facilities. DENC clarified that all QFs, regardless of technology, would continue to receive the same capacity *rates*, but the payments would be capped on an annual basis for QF resources at

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levels reflecting the operating characteristics and capacity value of these resources. DENC determined those levels by first calculating the levelized annual capacity value of a new CT, which it explained represents the maximum amount that a QF could receive for capacity if it generated at its rated capacity during all of the seasonal capacity on-peak hours, and which it based on 100% of the fixed costs of a new CT during the year that DENC has a capacity need. DENC then multiplied that benchmark capacity value of a fully dispatchable CT by percentage factors representing the capacity value relative to a CT for solar-tracking, solar-fixed tilt, and wind. These percentage factors (23%, 16%, and 13%, respectively) were based on the average MW output from each of these types of resources during the critical peak winter and summer hours. The result was proposed capacity caps of $8.55, $5.95, and $4.83/kW per year for solar – tracking, solar- fixed tilt, and wind, respectively. DENC explained that once an intermittent QF reaches the applicable limit for capacity payments on an annual basis, the cap would be triggered and the QF would receive no further capacity payments during that year of the contract term. Capacity payments would resume at the beginning of the next year of the contract term and continue through that contract year unless and until the point at which the annual cap is again reached. (*Id.* at 22-24.)

DENC noted that these caps are consistent with DENC's 2018 IRP and conform with the expected value of such facilities in PJM's capacity market. It also stated that they are consistent with FERC regulations that allow for the consideration of specific QF characteristics in determining avoided cost rates and with the complementary provisions of G.S. 62-156. DENC explained that by having a single set of capacity rates, all QFs will see the same price signal, but application of the caps will allow capacity payments to

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Sep 04 2019

be tailored to individual QF operating characteristics. DENC stated that this would help ensure that rates paid to intermittent QFs reflect their actual capacity value and that customers not overpay for these QFs' output. DENC posited that this approach achieves the intent of the Commission's directive to consider establishing separate rate schedules for intermittent QFs, which is to recognize the limited capacity value of these QFs. DENC noted in addition that this approach will result in efficient administration of QF contracts by retaining a single set of standard seasonal capacity rates, with the cap applied only to intermittent QFs. (*Id.* at 24-26.)

In its initial statement, the Public Staff objected to DENC's proposed cap. The Public Staff noted the steps taken by the Commission and General Assembly in 2017 to reduce the risk of overpayment for capacity to QFs. It also argued that capacity payments to an intermittent QF will inherently be lower than the capacity payments to a dispatchable QF if the seasonal allocation and capacity payment hours are accurately chosen to reflect the utility's seasons and hours of greatest capacity need. The Public Staff stated that it reviewed generation data from 61 solar facilities representing over 430 MW in DENC's 2018 fuel factor proceeding (Docket No. E-22, Sub 558) and found that the average capacity factor during the twelve months ending June 2018 was 18.2%, with a maximum of 25.1%. The Public Staff also stated that information DENC provided in discovery indicated that the capacity cap would affect tracking solar facilities with a capacity factor above 25.8%, which suggested that few QFs would actually hit the capacity cap. The Public Staff caveated, however, that this information is based on existing facilities that may have different efficiencies and operating characteristics than newer facilities eligible for these rates that may be constructed with higher DC to AC

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ratios, more efficient panels, or other factors that may increase the output of their system relative to existing facilities. (Public Staff Initial Statement at 60-62.)

The Public Staff also questioned DENC's approach of defining its seasonal allocation of capacity need to be consistent with its membership in the PJM market, when the capacity needs of the PJM market as a whole are different from the capacity needs of a utility operating in North Carolina. The Public Staff recommended that instead of the cap on capacity payments, DENC should evaluate alternative seasonal allocation and capacity payment hours that align more directly to DENC's system (as opposed to the PJM system as a whole). (*Id.* at 62-64.)

In his affidavit, NCSEA witness Johnson claimed that adopting more accurate price signals as he proposed would eliminate the potential that a QF will be over-compensated for capacity and therefore make DENC's proposed annual capacity payment cap unnecessary. (Johnson Affidavit at 78.)

SACE did not comment on DENC's proposed annual capacity cap.

In its reply comments, DENC explained that the proposed annual cap on capacity payments is an administratively efficient way to accomplish two goals. First, DENC argued that it links IRP principles to avoided cost payments. DENC explained that its IRP values solar capacity at 23% of nameplate capacity, consistent with its intermittency and non-dispatchability, and with the resulting Capacity Performance risk in the PJM capacity market, and that the cap accounts for that solar capacity value. Second, the cap provides a useful and reasonable way to reduce the risk that customers overpay for capacity beyond DENC's actual avoided costs. DENC acknowledged the progress made by House Bill 589 and the 2016 Order toward reducing the risk of customer

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Sep 04 2019

overpayment, but stated that that progress did not eliminate the need for the cap as a useful stopgap to prevent overpayment that could still occur due to potential imperfections in the rate design, peak hours selection, and CT seasonal cost allocations. (DENC Reply Comments at 38.)

In addition, noting the Public Staff's recognition that its calculated historical average solar capacity factor was based on existing solar facilities, DENC stated in addition that solar technology is advancing and the lower historical capacity factors (associated with existing units many of which are fixed tilt) may not accurately represent future performance of solar resources (which could be tracking solar units). Given this uncertainty of new solar QF capacity factor performance in the future, and the likelihood that new units will utilize tracking solar technology with higher capacity factors, DENC argued that the capacity payment cap would provide a good safeguard to protect customers from overpaying for capacity. (*Id.* at 38-39.)

Discussions & Conclusions

G.S. 62-156(b)(3) provides that a utility's future capacity need for purposes of determining rates to be paid for capacity is only avoided in years when the utility's most recent IRP identifies such a need "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 2016 Order, consistent with House Bill 589, the Commission concluded that avoided capacity payments should be offered to QFs only in years in which the relevant utility's IRP shows a capacity need. The Commission also acknowledged, however, that "the mere presence of QF capacity, including solar nameplate capacity, does not always translate into an avoidance of capacity needs by the utility." (2016 Order at 49.) The

Commission acknowledged the factors permitted to be considered in determining avoided cost rates under 18 C.F.R. § 292.304(e) and G.S. 62-156. (*Id.* at 49, 98.) The Commission concluded that an avoided cost rate based on the characteristics of the QF-supplied power could be appropriate in future proceedings, and directed the Utilities to "include proposed rates and data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings" in this proceeding. (*Id.* at 50.) The Commission concluded that the Utilities should propose schedules specific to intermittent, non-dispatchable QFs in this proceeding "if the Utilities' cost data demonstrates marked differences in the value of the energy and capacity provided by these QFs" (*Id.* at 98.) and directed the Utilities to address a "continued evaluation of capacity benefits of QF generation." (*Id.* at Ordering Paragraph 16.)

The Commission finds that DENC's proposed annual cap on capacity payments to intermittent QFs not only appropriately responds to the Commission's directives in the 2016 Order but is consistent with the findings of that Order and with G.S. 62-156 and FERC's regulations implementing PURPA. DENC provided data showing a marked difference in the value of the capacity provided by intermittent QFs on its system, particularly during the times when power is most needed. This evidence was not controverted by any party. DENC's approach to calculating the caps is straightforward, and is appropriately consistent with DENC's IRP and the Capacity Performance risk for solar facilities in the PJM capacity market. We agree that this approach achieves the intent of the 2016 Order directive to consider separate rate schedules, as it recognizes the limited capacity value of intermittent non-dispatchable QFs in an administratively efficient manner. We also agree that it is consistent with FERC's regulations allowing

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for consideration of QF characteristics including dependability in determining avoided cost rates and with G.S. 62-156, because it recognizes that even in years when DENC's IRP identifies a need for capacity, that identified need cannot always be met by this type of small power producer resource based upon its availability and reliability of power.

With regard to the continued risk of overpayment to QFs, the amendments to G.S. 62-156 made by House Bill 589 both reduced the size eligibility of QFs for the standard offer and reduced the term of a standard offer contract term. The Commission made findings in the 2016 Order consistent with those changes and based on its finding that the Utilities are overpaying for QF power under standard offer contracts entered into in previous biennial periods. These developments have reduced the risk of overpayment for QF capacity to the Utilities and to customers.

However, the Commission is persuaded by the evidence presented by DENC that there is still some risk of overpayment against which the annual cap would provide a backstop. This is due in part to the fact that, while DENC has proposed avoided cost rate design elements that we have found to be reasonable and appropriate based on the information known at the time, inevitably there will be some mismatch between projections and actual results that could result in overpayment to QFs. It is also due to the potential recognized by the Public Staff that future solar facilities may well have higher capacity factors, resulting in a higher level of annual payment to solar QFs, which would not reflect the true capacity value of these facilities to DENC. While the recent changes to North Carolina's PURPA implementation should help reduce overpayment risk, that improvement does not prohibit further refinements where appropriate,

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consistent with the PURPA mandate that utilities not pay more for QF power than the avoided cost.

With regard to NCSEA witness Johnson's comments on the capacity payment cap, as noted above we have already determined that witness Johnson's proposed rate design is not appropriate. However, we agree with DENC that its willingness to utilize a 45/40/15 seasonal allocation of capacity should reduce the likelihood that the cap would be triggered, while still appropriately reflecting DENC's membership in summer peaking PJM as well as recent winter peaks, and providing a stopgap against overpayment. Additionally, in practical terms, the Commission finds that DENC's approach of maintaining rates consistent for all QFs but imposing a cap on intermittent QFs, and starting over in each year of the contract term, is a reasonable and equitable approach to reflecting the characteristics of these QFs in avoided capacity rate design.

Based on all of the above, we find that DENC's proposed annual payment cap appropriately reflects the capacity value of intermittent QFs relative to fully dispatchable CT facilities on its system, and therefore conclude that it is reasonable for DENC to implement the annual caps on avoided capacity payments proposed in its Initial Statement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding is contained in the Initial Statements of DENC, the Public Staff, and NCSEA, witness Johnson's affidavit, DENC's reply comments and the entire record in this proceeding.

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Summary of the Evidence

In its Initial Statement, DENC explained that in the Order on Inputs, the Commission determined that the Utilities "should use the 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." DENC also noted that the Commission listed several items that should be included in the installed cost of a CT, including: the cost of land for a greenfield site; transmission interconnection costs (excluding network upgrade costs); economies of scale to include the cost benefits associated with building multiple CTs at a single site, up to four units, but excluding economies of scope for the cost benefits associated with building multiple CTs at the same time; a reasonable contingency adder; and tailoring to the extent clearly needed to adapt any such information to North Carolina and Virginia. DENC stated that, consistent with the method used in the compliance filing in the 2016 Case, it used the applicable costs of the Greensville combined cycle power plant as the basis for the CT equipment costs presented in this case. DENC explained that the Greensville plant's costs are current and verifiable and represent DENC's actual procurement costs of the CT equipment related to a power plant. (DENC Initial Statement at 14-15.)

For the remaining costs of an installed CT, including construction and owner costs, DENC utilized the PJM cost of new entry estimates. DENC explained that these estimates are 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 (Brattle Study). To tailor the Brattle Study results, DENC made several additional adjustments, including: adjusting the EPC construction labor and equipment costs to reflect economies of scale related to the construction of a two-unit CT site; adjusting sales tax to reflect rates applicable for Virginia; adjusted electric and gas interconnection costs to reflect costs expected for a CT constructed by the Company in Virginia or North Carolina; adjusting fuel costs for startup to reflect the cost of gas and oil during start-up testing and to account for PJM energy revenues; and eliminating financing fees as financing costs are included later in the CT annual carrying cost calculations. Because the Brattle Study assumed a CT with a commercial operations date (COD) of 2022, DENC de-escalated the construction and owner cost estimate for a 2019 COD. (*Id.* at 15-16.)

DENC then calculated the cost breakdown of the new peaker facility, with a total overnight cost of the hypothetical CT (CT equipment costs plus construction and owner costs) equal to $178.7 million and a resulting total installed cost of $559.8/kW. DENC converted the installed cost value to annual fixed costs inclusive of financing costs, allocated to seasons, divided by the applicable on-peak hours, and then levelized, to determine the avoided capacity cost rates. DENC's first avoidable capacity cost rates begin in 2022, as that is the first year DENC's 2018 IRP shows the first avoidable capacity. (*Id.* at 16-18.)

In its Initial Statement, the Public Staff acknowledged DENC's reliance upon the Brattle Report data as its starting point for CT cost, and stated that it continues to support the use of publicly available cost data, both for the transparency it provides for avoided cost rates, as well as for the general reasonableness of current published cost data that has gone through extensive review prior to publication. The Public Staff noted that tailoring this data, as appropriate, to reflect the expected cost of new capacity additions by the utility is reasonable. The Public Staff recommended that DENC evaluate and apply, as

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Sep 04 2019

appropriate, cost increments and decrements to the publicly available cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility. Finally, the Public Staff stated that it reviewed the capital cost inputs and other assumptions incorporated in DENC's proposed rates and found them reasonable for the determination of DENC's avoided capacity rates. (Public Staff Initial Statement at 17-18.)

In its Initial Statement, NCSEA acknowledged that the Utilities used the "peaker method" where the capacity price in the calculation is based upon the fixed costs of a CT. NCSEA and witnessBeach opposed the use of the peaker method to determine capacity rates and stated that the CT peaker method is costly as "Utilities" allocate much of the capacity price to winter peak hours, when gas demand peaks and gas pipeline capacity is constrained and CTs need to be served with firm pipeline capacity or to have a backup supply of an alternative fuel. NCSEA stated that these two factors require a reasonable premium to be added to the CT costs used to set the winter capacity price. (NCSEA Initial Statement at 23-24). Witness Beach asserted that the additional costs needed to firm the CT's fuel supply should be added to the CT costs used as the basis for QF capacity rates in the winter months. (Beach Affidavit at 4.) SACE did not comment on DENC's installed CT costs.

In its reply comments, Duke opposed NCSEA's recommendation that a hypothetical adder for firm natural gas pipeline transportation capacity cost be included in the utilities' CT costs. Duke asserted that NCSEA's proposal would deviate from Duke's consistent application of the Peaker Methodology in North Carolina by assigning

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a cost premium solely to the winter capacity price period versus allocating DEC's and DEP's avoided capacity costs between the winter and summer periods based upon loss of load risk. Finally, Duke disputed NCSEA witness Beach's quantification of the additional pipeline capacity cost proposed to be added to the avoided winter capacity rate, arguing that it was either miscalculated or greatly excessive. (Duke Reply Comments at 34-35.)

In its reply comments, DENC stated that it has long advocated for the use of a brownfield CT to determine avoided capacity cost rates, and agreed with the Public Staff's comments regarding the potential efficient use of brownfield sites for the construction of new CT facilities because of their land availability and existing gas and electrical infrastructure. DENC stated that, if the Commission directed, it will evaluate the potential for such cost adjustments in the next avoided cost proceeding. (DENC Reply Comments at 29.)

<u>Discussion and Conclusions</u>

Based on the evidence in this proceeding, the Commission concludes that DENC's CT cost calculations, which are essentially not controverted by any party, should be accepted for purposes of this proceeding. DENC has complied with the Commission's directives in the Order on Inputs by using a publically available source for CT data and appropriately tailoring that cost data consistent with its own facilities. The Commission also finds that the Public Staff's recommendation that the Utilities adjust installed CT costs to reflect brownfield costs is reasonable and appropriate and directs the Utilities to evaluate the potential for such cost adjustments in the next avoided cost proceeding.

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The Commission also declines to accept NCSEA witness Johnson's recommendations on this topic. While he criticizes the peaker method, the Commission is not persuaded to shift away from the peaker method or modify its application other than to consider brownfield cost data as discussed above. We also conclude that NCSEA's recommendation to include a CT cost adder for firm natural gas transportation is not necessary at this time for the reasons provided by Duke. In addition, this proposal is particularly not appropriate for DENC since while witness Johnson described the "Utilities" as allocating most of their capacity costs to the winter season, DENC as discussed elsewhere herein will be using a seasonal allocation of 45% summer/40% winter/15% shoulder.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding is contained in the Initial Statements of DENC, Public Staff, and SACE, the reply comments of DENC and Public Staff, and the entire record in this proceeding.

Summary of the Evidence

In its Initial Statement, DENC noted that House Bill 589 requires payment to QFs for capacity only in years where a utility's most recent biennial IRP has identified a capacity need and "the identified need can be met by the type of small power producer resource based upon its availability and reliability of power." DENC also noted that consistent with House Bill 589, the 2016 Order similarly directed the Utilities to provide levelized payments for capacity to QFs over the standard contract term only in years when the Utilities' respective IRP forecast periods demonstrate a capacity need. Based upon these directives, DENC proposed seasonal levelized rates that included no avoided

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capacity costs through 2021, since DENC's most recent biennial IRP, the 2018 IRP, did not identify an avoidable capacity need represented by a CT addition until 2022 for both Schedule 19-LMP and Schedule 19-FP. (DENC Initial Statement at 1-3, 17-18.)

In its Initial Statement, the Public Staff recognized that DENC's IRP currently indicates its next capacity need is in year 2022. The Public Staff also addressed DENC's avoided capacity cost calculations for its Schedule 19-LMP and Schedule 19-FP. As to the Schedule 19-LMP, the Public Staff found that "consistent with" the 2016 Order, DENC proposed to allow the QF to receive an avoided capacity payment of 0.442 cents per kWh, based on the PJM Base Residual Auction, commencing in a year in which there is a capacity need. With respect to DENC's avoided capacity costs calculation for Schedule 19-FP, the Public Staff stated that the installed CT cost used by DENC "is consistent with" the installed cost of a CT utilized in DENC's IRP, which shows the first deferrable capacity need in 2022. (Public Staff Initial Statement at 16-17, 65-66.)

In its initial comments, SACE argued that DENC did not comply with the Commission's 2016 Order directive to provide avoided capacity payments in years that the utility's IRP forecast period demonstrates a capacity need. SACE argued that because the Virginia State Corporation Commission (VSCC) initially rejected DENC's IRP as originally filed in 2018 that IRP does not accurately represent DENC's future capacity plans and cannot be relied upon in this proceeding. SACE also contended that DENC did not identify a "preferred plan" in its 2018 IRP, and that absent a preferred plan, the capacity need should be demonstrated based on the Alternative Plan that anticipates DENC's most immediate capacity need. Finally, SACE asserted that certain capacity additions in 2019, 2020, and 2021 reflected in DENC's 2018 IRP could be deferred, delayed, or reduced "as a result of QF capacity contributions," and therefore DENC's calculation of avoided capacity costs as not including such costs through 2021 does not comply with FERC's conclusion in Order No. 69 that QFs should be compensated for avoided capacity if purchasing from that QF allows the utility to avoid construction, to build a smaller unit, or to purchase less firm power. (SACE Initial Comments at 20-22.)

In its reply comments, the Public Staff shared intervenors' concerns related to the lack of a specific statement of capacity need in each utility's IRP. Because the IRP is utilized in various regulatory proceedings, the Public Staff recommended that a definitive statement of need, subject to approval by the Commission, would remove uncertainty surrounding the exact year of capacity need and provide a clearer standard for all parties to these various regulatory proceedings. In its reply comments, Duke agreed to more clearly address this issue in future IRPs within a new Statement of Need Section. (Public Staff Reply Comments at 14.)

In its reply comments, DENC explained that although the VSCC initially rejected DENC's 2018 IRP, the VSCC required DENC to refile its 2018 IRP by March 7, 2019, which filing DENC made. DENC further explained that as indicated in its updated 2018 IRP filing, its need for capacity had not changed from the initially filed 2018 IRP; based on the input assumptions directed by the VSCC to be used in the refiled 2018 IRP, including the solar build-out per the Virginia GTSA in Plan F (No CO2 Plan), the resulting capacity expansion plan continued to show the first CT build in the No CO2 case to occur in 2022. (DENC Reply Comments at 32-33.)

DENC also noted that its reliance on a No CO2 Plan is the same approach that it has taken in the last several North Carolina avoided cost proceedings, and explained that

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this approach is consistent with the Commission's conclusions in previous proceedings that only known and quantifiable costs be reflected in avoided cost calculations. DENC stated that because, currently, CO2 costs are not yet known or quantifiable, a preferred plan is not relevant to the determination of avoided cost, and reliance on the no-CO2 plan(s) in this proceeding is appropriate. (*Id.* at 33.)

With regard to compliance with Order No. 69, DENC explained the practical reality that new QFs signing PPAs during this biennial period will not avoid any capital costs related to near-term solar and wind generation projects in years 2019-2021 identified by SACE. DENC pointed out that, as SACE acknowledged, some of the generation projects projected for 2019-2021 in the IRP are already under construction. DENC concluded that as a result purchases from QFs that establish legally enforceable obligations (LEOs) under this proceeding will not avoid those costs, and therefore will not allow DENC to avoid capacity costs as contemplated by Order No. 69. (*Id.* at 34.)

<u>Discussion and Conclusions</u>

G.S. 62-156(b)(3) provides that

> The rates to be paid by electric public utilities for power capacity purchased from a small power producer shall be established with consideration of the reliability and availability of the power. A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) 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 2016 Order the Commission determined that this avoided capacity payment methodology is also appropriate with regard to QFs that are not small power producers, finding that the changed economic and regulatory circumstances facing QFs and utilities justified the change. (2016 Order at 48.) The Commission concluded that it is reasonable for the Utilities to "provide levelized capacity payments for the full term of the ten-year standard offer, including capacity payments in years prior to the utility's first capacity need reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs." (*Id.*) In the 2014 avoided cost proceeding, the Commission concluded that only known and quantifiable costs should be reflected in avoided cost calculations. (Order on Inputs at 44; Phase II Order at 24.)

Based on these considerations and the evidence presented in this case, the Commission concludes that DENC has reasonably calculated avoided capacity rates for purposes of this proceeding consistent with a capacity need starting in 2022. We agree with DENC that its approach of relying on the No CO2 Plan is consistent with the Commission's conclusions in previous proceedings that only known and quantifiable costs be reflected in avoided cost calculations. Because CO2 costs are not yet known or quantifiable, reliance on the no-CO2 plan(s) in this proceeding is appropriate.

The Commission also concludes that DENC's capacity need projection is consistent with Order No. 69, because until 2022 purchases from QFs will not allow DENC to avoid construction, to build a smaller unit, or to purchase less firm power as denoted in that Order. We find persuasive the practical reality explained by DENC that new QFs signing PPAs during this biennial period will not avoid any capital costs related to near-term projects identified in the IRP for years 2019-2021, some of which as SACE acknowledged are already under construction. We agree that purchases from QFs that establish LEOs under this proceeding will not avoid those costs, and therefore will not allow DENC to avoid capacity costs as contemplated by Order No. 69. As

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FERC's regulations make clear, utilities are not expected to pay for capacity they do not need. (18 C.F.R. § 292.304(a).)

Finally, the Commission finds merit in the Public Staff's recommendation that the Utilities include a definitive statement of capacity need in future IRPs in order to remove uncertainty surrounding the exact year of capacity need and provide a clearer standard for all parties to the various regulatory proceedings in which the IRP is utilized and referenced. The Utilities should include such a statement of need in future IRPs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting these findings of fact is found in the Initial Comments of NCSEA and the Hydro Group, the reply comments of the Public Staff, NCSEA and SACE, the testimony of DENC witness Petrie, Duke witnesses Johnson and Snider, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Evidence

In its Initial Comments, NCSEA requested that the Commission "try to ensure regulatory continuity and certainty" for existing QFs seeking to renew a PPA upon its expiration or enter into a new PPA. NCSEA argued that existing QFs have an expectation of continuity for their rights after their initial PPA expires, and that the Commission should recognize these "residual rights." (NCSEA Initial Comments at 10, 49.)

The Hydro Group also contended that QFs should have an expectation of a renewal of capacity from expiring PPAs and automatic right to renew an expiring PPA. The Hydro Group asserted that renewal and extensions of QF contracts establish the need for their capacity as of the date the original contract was executed and recommended that

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the Commission "subject capacity deficiencies in the IRP proceeding to additional scrutiny." (Hydro Group Initial Comments at 8-11.) The Hydro Group cited to an Idaho Utilities Commission (Idaho Commission) decision that the "capacity deficit date" for renewed contracts between QFs and utilities is determined as of the date the original contract was executed. (*Id.* at 10.) In Reply Comments, NCSEA and SACE agreed with the Hydro Group's position and recommendation. (NCSEA Reply Comment at 11; SACE Reply Comments at 6.)

The Public Staff, however, disagreed with the Hydro Group's premise that in not assuming QF PPAs are renewed or replaced in kind, capacity payments to QFs will be reduced, and contended that for planning purposes, the assumption that QF PPAs will expire at the end of the current PPA term effectively decreases each utility's avoidable capacity, and thus accelerates the need for undesignated future resources. The Public Staff renewed its recommendation made in the 2018 IRP proceeding (Docket No. E-100, Sub 157) that the Utilities include in future IRP filings a statement of need specifying the assumptions used in the determination of its first year of capacity need, including whether existing QF contracts are assumed to have been renewed, replaced in kind, or terminated. (Public Staff Reply Comments at 27-28.)

In his direct testimony, Public Staff witness Hinton recommended that the Commission direct the Utilities clarify the point when an existing QF seeking to renew its PPA can establish a new LEO for both calculating rates and determining when the facility will be eligible to receive a capacity payment. Witness Hinton contended that this period of time should be long enough to allow the QF to have sufficient information regarding the rates for which it may be eligible in order to determine whether the QF

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should seek to renew its PPA, but not so long that a QF could contract for rates that are misaligned with current avoided costs. (Tr. Vol. 6 at 316-317.)

NCSEA witness Johnson's direct testimony recommended that the Commission clarify that QFs with contracts expiring between now and 2028 are fulfilling an existing capacity need, and that those QFs will continue to receive full capacity cost recovery if and when they sign a "renewal contract." Witness Johnson argued that in order for the QF to continue receiving capacity payments, the Commission should require QFs to file notice with the utility at least three years before the QF's current PPA is set to expire, indicating the QF's commitment to continue to provide capacity to the utility. (Tr. Vol. 6 at 203, 212.)

In response to Public Staff witness Hinton, on rebuttal DENC witness Petrie stated that a one-year notice period ahead of the expiration date of a current PPA, with the requirement to execute the PPA consistent with the currently effective LEO form, achieves the balance identified by witness Hinton. Witness Petrie explained that one year provides the QF sufficient time to make an informed decision as to whether or not to renew its PPA, but not so much time as to result in inaccurate avoided cost rates. He also disagreed with NCSEA witness Johnson's recommendation that a QF should notify a utility three years ahead of its PPA expiration and lock in a right to capacity rates as of that time. He testified that a minimum three-year notice period unnecessarily increases the risk of inaccurate avoided cost rates. He concluded that QFs with an expiring PPA should receive capacity payments under a new PPA, using a capacity rate that is based on DENC's capacity position and cost of a new CT resource at that particular time. (Tr. Vol. 5 at 45-47.)

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In his rebuttal testimony, Duke witness Johnson noted Duke's policy of accepting a QF's request to enter into a new PPA no earlier than twelve months prior to the end of the QF's existing PPA term. (Tr. Vol. 2 at 280.) Duke witness Snider opposed NCSEA witness Johnson's recommendation for a three-year notice as essentially allowing a pre-existing QF to establish a "placeholder" LEO three or more years in advance of its contract expiration to pre-emptively reserve capacity to be delivered at avoided cost rates that presumably will be established in the future closer in time to the period of delivery. He noted that it would be inconsistent with North Carolina's implementation of PURPA to prospectively commit Duke to continue to pay a QF for capacity "without interruption" if DEC and DEP's IRPs project that such a need does not exist in a given year. He also stated that the policy seems to advantage pre-existing QFs over new QFs and other capacity resources without any meaningful indication when the QF making this "pre-commitment" will actually execute a PPA and make a binding commitment to deliver energy and capacity in the future. He stated that allowing a QF to establish a LEO three years ahead of its contract expiry and to fix its pricing at the time of this "commitment" would also create significant risk of inaccurate avoided costs (potentially to the significant disadvantage of customers) and would be inconsistent with Duke's current policy allowing a QF to commit to a new PPA up to a year ahead of commencing the new delivery period as noted by Duke witness Johnson. Witness Snider noted that NCSEA witness Johnson did not address when avoided cost pricing would be determined or when the QF would actually execute a PPA under his proposal. (Tr. Vol. 2 at 107-109.)

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Duke witness Snider also disagreed with recommendations that QFs be presumed to continue to provide and receive payment for capacity after their initial PPA terms have expired. He pointed out that FERC's regulations recognize a QF's commitment to sell "over a specified term," and that it seems inconsistent to presume that a commitment made for such a specified term would obligate the QF to continue to deliver after the initial term ends. He emphasized that at the end of the term, the QF has the right to make a business decision whether to not to establish a new LEO. He noted that NCSEA witness Johnson's proposal would discriminate against new QFs in favor of existing QFs. He also noted that investors in existing projects are receiving payments at approximately twice competitively procured rates for renewables. Finally, he distinguished utility-owned facilities from QFs and pointed to the 2016 Order's rejection of comparisons between these distinct generation facilities. (Tr. Vol. 2 at 101-107.)

At the hearing, Public Staff witness Hinton testified in response to Duke counsel's questioning that a one-year notice period for QFs with negotiated PPAs strikes the balance he recommended, as long as the QF was not changing its facility. (Tr. Vol. 7 at 96-97.)

<u>Discussion and Conclusions</u>

The Commission agrees with the Public Staff that these issues will come to the forefront more in the coming years as existing QF PPAs reach their expiration and QFs decide whether to renew their offers to sell to the Utilities. Based on the foregoing evidence, the Commission finds it reasonable to direct QFs that wish to renew PPAs to notify the relevant utility no more than one year and not less than six months prior to the PPA expiration date of their intent to renew. We find appropriate the Public Staff's

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Sep 04 2019

recommendation that it would be helpful to the Utilities and to QF developers to clarify the point when an existing QF seeking to renew its PPA can establish a new LEO for calculating rates and determining when the facility will be eligible to receive a capacity payment. We agree that this notice period should strike a balance between being long enough to provide the QF sufficient information to determine whether the QF should seek to renew its PPA, but not so long that a QF could contract for rates that are misaligned with current avoided costs. We conclude that a notice period from six months to one year prior to the PPA expiration date achieves that balance. We agree with the Utilities that NCSEA's recommendation for a three-year advance notice would unnecessarily increase the risk of inaccurate avoided cost rates and conflict with G.S. 62-156 and this Commission's previous determinations that capacity payments should be made in accordance with years of need.

With regard to arguments that QFs enjoy "residual rights" in renewal PURPA PPAs, we find no rational basis for such a position. We agree with witness Petrie that QFs that enter into new (renewal) PPAs should receive a capacity rate that is based on the utility's capacity position and the cost of a new CT resource at that time in the future. The Commission recognizes as it has in previous proceedings the right of a QF to long-term fixed rates under Section 210 of PURPA, and FERC's *J.D. Wind* orders and regulations. Specifically, Section 292.304(d)(2) allows a QF to establish an LEO committing to sell energy or capacity over a "specified term." However, G.S. 62-156 and the 2016 Order specify a ten-year term for the standard offer PURPA contract in North Carolina. In the 2016 Order, the Commission stated that it would continue its approach of balancing the federal and State public policy requirements to encourage QF

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development against the risks and burdens (such as overpayment, default, and stranded costs) that long-term contracts place on utility customers. The Commission concluded that a 10-year term strikes that balance. (2016 Order at 34-35.) To presume that QFs should continue to receive the same rates and terms, including capacity payments, provided in their original PURPA contracts after those PPAs' expiration would upset the balance the 10-year term is achieving.

It would also be inconsistent with the provision of FERC's regulations that avoided cost rates under Section 292.304(d) are calculated at the time the LEO is incurred. It is not reasonable to conclude that the original LEO stands for as many renewals as the QF wants to make. Each time the QF wants to renew, there must be a new LEO and therefore a new set of rates and terms, which may or may not include capacity in every year of the contract term depending on the utility's need.

The Commission also finds the testimony of Duke witness Snider on this issue persuasive and agrees that NCSEA's position would discriminate against new QFs, and that the comparison that Dr. Johnson makes between QF and utility generation is invalid for the reasons discussed in the 2016 Order. We find in addition that as QFs are free to make the business decision at the end of a PPA term to renew or not renew and sell their power elsewhere, this decision does not discriminate against QFs.

In sum, the Commission concludes that a QF seeking to renew a PURPA contract must establish a new LEO by providing the six month to one year advance notice discussed above to the utility, and will receive rates and terms approved by this Commission for the biennial proceeding during which that LEO is established. Any

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payment for capacity for a renewal PPA will depend on the utility's identified capacity need at the time the LEO is established.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding is contained in the Initial Statements of DENC and the Public Staff, the initial comments of NCSEA, the affidavit of witness Johnson, the reply comments of DENC, the Public Staff, NCSEA, and SACE, the testimony of DENC witness Petrie, Duke witness Snider, Public Staff witness Hinton, and NCSEA witness Johnson, and the entire record in this proceeding.

Summary of the Evidence

Consistent with prior biennial avoided cost proceedings, DENC's Initial Statement proposed an assumed in-service date for QFs eligible for standard offer rates and terms established in this proceeding to be January 1, 2019.

NCSEA's initial comments argued that the Utilities' avoided capacity calculations include "unrealistic assumptions" about when QFs will begin providing capacity. Basing its arguments upon the "well-documented delays" in the Utilities' interconnection queues, NCSEA contended that it is reasonable to assume that a QF entering into a PPA in this biennial period will not begin providing capacity until December 2021, or later. NCSEA therefore proposed the Utilities assume a December 31, 2021 in-service date for the purpose of calculating avoided capacity costs (both the quantification of the costs and the determination of the number of years in which there is a capacity need), which it argued would permit QFs to provide capacity during more years in which the Utilities have shown needs for capacity. (NCSEA Initial Statement at 11-12.)

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NCSEA also argued that the Commission should direct the Utilities to calculate avoided cost rates in negotiated PURPA PPAs based on the presumed in-service date of the QF subject to the negotiated PPA. NCSEA witness Johnson suggested that for negotiated PURPA PPAs, the Utilities could "specify[] a 'cost curve' (or matrix of rates) which varies based upon the actual in-service." (*Id.* at 12.) Witness Johnson asserted that this cost curve could be used during rate negotiations with large QFs to determine what rates will apply if the project is delayed. (Johnson Affidavit at 59.)

In its reply comments, SACE stated that the presumptive in-service date for QFs, for the purpose of calculating avoided capacity costs, should more accurately reflect the time at which those QFs are likely to actually begin providing capacity, and that using December 31, 2021, as the presumed in-service date for QFs signing contracts in this biennial period was reasonable. (SACE Reply Comments at 6.)

In its reply comments, the Public Staff disagreed with to NCSEA's proposal, stating that for purposes of establishing the term for a standard offer facility, the Utilities' current practice of assuming an in-service date in the year following the November 1 biennial filing date for avoided costs is a reasonable approach that treats existing facilities and new facilities equitably. The Public Staff also suggested that to the extent utility inputs change, such as the anticipated date of the first capacity need, the Public Staff would expect the Utilities to update their avoided capacity calculations for negotiated contracts. (Public Staff Reply Comments at 29.)

In its Reply Comments, DENC explained that by the very nature of the "standard" offer, assumptions must be made in setting standard rates. DENC pointed out that trying to account for every potential outcome—including adjusting assumed start dates based on

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uncertainty regarding QFs' commercial operations dates—would nullify the purpose of establishing standard rates and terms. DENC also noted that it has assumed a January 2019 start date for QFs entering into standard PPAs in every recent avoided cost proceeding as an administratively efficient way to develop standard rates and terms for small QFs. (Public Staff Reply Comments at 28-30.)

With regard to negotiated PPAs, DENC explained that it already calculates avoided cost rates for large QFs based on data available at the time the QF establishes an LEO, consistent with FERC and Commission directives, and that calculating rates based on the projected in-service date would be inconsistent with those determinations as well as unreasonably burdensome to the Utilities. Finally, DENC noted that under PURPA, the Utilities are only required to purchase QF output, and are not obligated to assist developers in determining which business plan will result in the most revenues. (DENC Reply Comments at 30-31.)

In direct testimony, DENC witness Petrie explained that the purpose of this docket is to develop reasonable avoided cost rates that apply to small QFs that sign a contract during the 2019-2020 biennial period, and argued that NCSEA's proposal would be impractical and inefficient, particularly for standard contracts. Witness Petrie questioned for example whether, assuming NCSEA's proposals were accepted, the assumed in-service date would change with each avoided cost proceeding, and if so, what standards would apply. He noted that NCSEA's proposal itself was arbitrary, since although assuming a January 1, 2022 in-service date may benefit a QF that is eligible for this biennial period's rates but does not for whatever reason come online until after 2019

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that assumption could result in over-payment to a QF that does achieve commercial operations before January 2022. (Tr. Vol. 5 at 30-32.)

Similarly, as to negotiated PURPA PPAs, witness Petrie reiterated that NCSEA's proposal would deviate from prior precedent, unreasonably burden the Utilities, add inefficiencies to the negotiation process, and offer QFs free optionality, the costs of which would be borne by the Utilities' customers. Further, witness Petrie pointed out that NCSEA's proposal is based upon the unsupported assumption that all QFs eligible for rates established in this proceeding will have not commenced the interconnection study process until this biennial period, disregarding the fact that QF developers may plan ahead and begin the interconnection process earlier in order to achieve commercial operations during this period. (Tr. Vol. 5 at 30-32.)

Duke witness Snider testified that, consistent with the design of the biennial standard offer in North Carolina, the rates in Duke's Schedule PP in this proceeding were calculated using the ten-year period 2019 through 2028. He stated that the factual basis underlying NCSEA's argument is flawed, explaining that although NCSEA asserted that smaller QFs eligible for the standard offer would not enter into service for multiple years, many of Duke's Section 3 Fast Track and Supplemental review interconnections complete construction and are placed in service in less than a year. Witness Snider also noted that QFs seeking to enter into a new PPA at the time their existing PPAs expire will immediately begin operation since they are already constructed. Finally, he emphasized that to the extent a QF seeks to time its LEO closer to its actual in-service date, it retains that right to delay establishing a LEO, and may also choose to negotiate a PPA instead of pursuing a standard offer rate. (Tr. Vol. 2 at 60-61.)

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In his direct testimony, Public Staff witness Hinton testified that for purposes of establishing the standard offer contract, the Utilities' current practice of assuming an in-service date in the year following the November 1 biennial filing date for avoided costs is a reasonable approach and treats existing and new facilities equitability. He contended that any shift of the start of the standard offer contract from the year immediately following filing of the new rate schedule would likely result in a mismatch of payments made to QFs and the utility's expected avoided energy costs and avoided capacity costs. (Tr. Vol. 6 at 316-317.)

In his testimony, NCSEA witness Johnson presented data regarding Duke interconnections to argue that most new projects falling within the current biennial time frame will not be energized until 2021. Witness Johnson did agree that small QFs proceeding under the Fast Track and Supplemental Review process can proceed more expeditiously than larger projects. He posited that a more realistic in-service date would result in roughly half the QFs in a biennial period having an actual in-service date before the assumed date, and the other half having an in-service date after the assumed date, and that this will not occur with a January 1, 2019, in-service date. He also contended that a January 1, 2019, in-service date produces distortions in the avoided cost calculations. He recommended that the Commission require the Utilities to publish a schedule of rates (or a formula) that varies over time, so that each QF signing a contract during the 2019-2020 biennial period could receive the appropriate rate based on its actual in-service date. Alternatively, he suggested the Utilities be required to use a more "reasonable assumption." Witness Johnson also claimed that the Utilities' concerns regarding his proposal were unwarranted, and that it would not be difficult or burdensome for the

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Sep 04 2019

Utilities to run their rate calculations using different assumed in-service dates for differing QFs. He agreed with the Utilities that avoided cost rates may not precisely match actual avoided costs and that some degree of simplification is reasonable and necessary, but argued that a desire for simplicity should not be an excuse for allowing calculations to become biased against QFs. (Tr. Vol. 6 at 203-204, 216-226.)

On rebuttal, DENC witness Petrie testified that the January 1, 2019 in-service date is the most administratively efficient method to develop standard rates and terms for small QFs. He pointed out that it would be impractical to use an assumed QF in-service date that is a full year past the end of the two year biennial period, especially considering the fact that the Company will file new forecasted avoided cost rates on November 1, 2020. He also noted that witness Johnson had not provided sufficient evidence to support his proposal or answered DENC's questions regarding how the proposal would work in practice. With regard to Witness Johnson's alternative proposal for a schedule of rates, witness Petrie reiterated that it would be unreasonable to complicate the standard offer with varying in-service dates and rate calculations, and that the increased administrative burden placed upon the Utilities would outweigh any additional granularity gained through acceptance of NCSEA's proposal. He testified further that NCSEA's approach would allow QFs to time their commercial operations date to the point in time during the biennial period when the rates are highest, which, in the Company's view, is inconsistent with a QF's election to provide energy and capacity pursuant to a LEO with rates calculated at the time the obligation was incurred. Finally, witness Petrie stated that PURPA requires utilities to purchase QF output; it does not

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require utilities to provide QFs with a level of optionality required to maximize QF earnings. (Tr. Vol 5 at 42-45.)

<u>Discussion and Conclusions</u>

Based on the evidence presented, the Commission finds that the Utilities' practice of assuming an in-service date for new QFs of January 1 of the year following the filing of their initial statements in these avoided cost proceedings is reasonable and appropriate, because it treats new and existing QFs equitably, and is an administratively efficient way to develop standard rates and terms for small QFs. We are not persuaded that the administrative burden associated with alternative proposals are outweighed by any potential benefits, and find that these proposals would inappropriately burden Utilities with helping developers choose the most lucrative in-service dates in order to maximize revenues.

The Commission recognizes that the assumed in-service date will not be accurate in all instances. However, some assumptions must be made in developing an making the standard offer to QFs and the Commission finds that the January 2019 start date is a reasonable assumption for the Utilities to make. We agree with the testimony presented that delaying the assumed in-serve date is inconsistent with the nature of a standard offer contract. We also agree with DENC that trying to account for every potential outcome—including adjusting assumed start dates based on uncertainty regarding QFs' commercial operations dates—would nullify the purpose of establishing standard rates and terms, and would place an unreasonable administrative burden on the Utilities. We find particularly persuasive witness Petrie's point that it would be impractical to use an assumed QF in-service date that is a full year past the end of the two year biennial period, especially considering the fact that the Utilities will file new forecasted avoided

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cost rates on November 1, 2020. In addition, we find persuasive the Public Staff's point that any shift of the start of the standard offer contract from the year immediately following the filing of the new rate schedule would likely result in a mismatch of payments made to QFs and the utility's expected avoided energy costs and avoided capacity costs.

The Commission also finds that witness Johnson did not justify the additional administrative burden that would accompany his proposal by addressing the valid questions raised by the Utilities as to how the proposal would work in practice. He appeared to doubt the validity of such questions raised by DENC, such as how the assumed in-service date would adjust in future proceedings, and did not provide any answers, but the Commission finds the practical issues raised by DENC to be valid and necessary to address in order to evaluate how a different approach would actually be implemented. Neither did witness Johnson respond to DENC's point that his proposal disregards the reality that QF developers may plan ahead and begin the interconnection process earlier than this biennial proceeding in order to be ready to achieve commercial operations sooner.

With regard to NCSEA witness Johnson's alternative proposal for a schedule of rates, the Commission finds that it would be unreasonable to complicate the standard offer with varying in-service dates and rate calculations. Further, we find notable his testimony that this approach would allow QFs to time their commercial operations date to the point in time during the biennial period when the rates are highest. We agree with DENC that this approach is inconsistent with a QF's election to provide energy and capacity pursuant to a LEO with rates calculated at the time the obligation was incurred,

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and that it would inappropriately require the Utilities to provide QFs with a level of optionality required to maximize QF earnings. Finally, the Commission agrees with Duke that to the extent a QF seeks to time its LEO closer to its actual in-service date, it retains that right to delay establishing a LEO, and may also choose to negotiate a PPA instead of pursuing a standard offer rate.

In light of the foregoing, the Commission concludes that the Utilities may continue to assume an in-service date of January of the year following the November in which they submit their initial statements in these proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding is contained in the Initial Statements of DENC and the Public Staff, the initial comments of NCSEA, witness Johnson's affidavit, and the reply comments of DENC, the Public Staff, NCSEA, and SACE and the entire record in this proceeding.

Summary of the Evidence

In its Initial Statement, DENC acknowledged that in the 2016 Order, the Commission ruled that it would require the Utilities to "address the PAF and to support their recommendations for PAF calculations based on their evidence of peak season equivalent availabilities for the utility fleets in total in [their] initial filings" in this proceeding. DENC proposed to use the fleet Equivalent Availability (EA) to determine the PAF, which it calculated to be 1.070 and applied to its proposed Schedule 19-FP capacity rates. DENC explained that the EA represents the availability of the unit(s) during the defined period, and accounts for unit unavailability caused by planned, maintenance, and forced outages. DENC noted that it assumed peak seasons of June, July, August, and January-February in its PAF calculation, which PJM considers the critical months when system emergencies and performance assessment hours are expected. (DENC Initial Statement at 32-33.)

In its Initial Statement, the Public Staff asserted that each utility's PAF should incorporate the respective utility's prospective equivalent forced outage rate (EFOR), and not be based solely on historical availability data. It recommended that the Commission direct the Utilities to refile their fleet weighted average peak month EFORs using five years of historical data and at least five years of prospective data. The Public Staff asserted that the Utilities' historical data supports the use of June through August as summer peak months and December through February as winter peak months (and noted that DENC excluded December from its winter peak months). The Public Staff acknowledged, however, that DENC's proposed PAF of 1.07 based on historic operational data was an increase from DENC's 1.05 PAF approved by the Commission in the 2016 Order. (Public Staff Initial Statement at 69-70.)

In its initial comments, NCSEA stated that a PAF is used to ensure that QFs are not discriminated against in favor of rate-based generation and that the PAF should consider the availability of rate-based generation during all critical peak hours. NCSEA stated that the Commission stated in its 2016 Order that the availability of a CT is not determinative for the purpose of calculating a PAF. NCSEA and witness Johnson, in his affidavit, also stated that the Commission in that Order discussed alternatives for calculating the PAF in future proceedings and indicated a preference for consistency between avoided cost filings and other routine filings. Witness Johnson noted the peak months used by the Utilities in their respective PAF calculations. He did not oppose

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DENC's calculation or make a recommendation to the Commission specifically regarding DENC's PAF. (NCSEA Initial Statement at 30-32.)

In its reply comments, the Public Staff explained that although it initially advocated for the use of at least five years prospective EFOR data to bring to the forefront the "peak season" concept, subsequent to filing its Initial Statement the Public Staff better recognized the fundamental differences between EA and EFOR and the challenges associated with comparing the two separate metrics. The Public Staff also recognized the difficulty of adding a prospective element to the PAF calculation as it would introduce subjectivity. As a result, the Public Staff proposed that if a rate-based metric is applied, the use of three to five years of historic data is appropriate. The Public Staff also asserted that an EFOR metric does not properly address other types of outages that can occur during a peak season and suggested that other reliability metrics used by NERC such as the EUOR or WEUOR could be an appropriate metric that takes into account outages that can occur during peak periods such as forced outages, maintenance outages, and derates. The Public Staff stated that EUOR removes planned outages from the base calculation and therefore would not give a negative indication of utility unit performance during the critical peak seasons. Based on discussions with the Utilities, however, the Public Staff recommended that the Commission approve the initial PAF calculations proposed by the Utilities in their respective Initial Statements, but also direct the Public Staff, Utilities, and parties in this proceeding to discuss whether another metric, such as EUOR, may be a more appropriate reliability metric to support quantification of the PAF in future avoided cost proceedings. (Public Staff Reply Comments at 14-16.)

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Sep 04 2019

In its reply comments, DENC opposed the Public Staff's suggestion of the WEUOR to determine the PAF. DENC explained that the WEUOR is an obscure metric that DENC does not calculate and that the EA metric DENC used is more appropriate based on the 2016 Order. DENC argued that the PAF should be determined based on three years of EA history as that measure provides the most meaningful information because it is actual, observable, and recent as opposed to five years of data which is less relevant due to generation unit changes such as unit fuel conversions. Prospective EA data, DENC explained, would add subjectivity and unnecessary complication to the PAF calculation. DENC supported the Public Staff's shift away from using a prospective component in the PAF calculation. (DENC Reply Comments at 39-40.)

DENC also explained that the peak periods it used in its PAF calculation corresponded with the months PJM considers to be the peak months from a system operations perspective, when system emergencies would likely occurs, and when planned outages would not be scheduled. DENC stated that including December or March in its calculation would mean the majority of months in a year would be 'peak' months and that DENC uses these months for planned outages in order to spread out the spring and fall outages. DENC argued that including December or March data would increase the PAF and unfairly burden electric customers with increased QF capacity costs due to the Company's efforts to efficiently plan outages for its generation units. DENC stated that including March and December would also run counter to the Commission's finding in the 2016 Order where the Commission stated that "Public Staff's witnesses use of availability factor is flawed because it includes planned outages that a utility intentionally

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schedules for off-peak shoulder periods when electricity demand is low." (2016 Order at 55; DENC Reply Comments at 41-42.)

In its reply comments, NCSEA stated that the calculation of the PAF should be forward-facing to account for technological improvements. In its reply comments, SACE asserted that based on historical data, the Utilities should include June and September in its summer peak months and March and December in its winter peak months. (NCSEA Reply Comments at 12; SACE Reply Comments at 8.)

Discussion and Conclusions

In the 2016 Order, the Commission concluded that a PAF of 1.05 should be utilized by the Utilities in their respective avoided cost calculations for all QFs except hydroelectric facilities without storage capability.[2] The Commission also directed the Utilities to address the PAF and support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for their fleets in total in their initial filings in the next biennial avoided cost proceeding.

Based on the evidence presented, the Commission concludes that DENC has met this directive, and that its proposed PAF of 1.07 should be accepted for purposes of this proceeding consistent with the Public Staff's recommendation. We find persuasive the comments of DENC and the Public Staff as to the value of basing the PAF calculation on historical as opposed to prospective data. We also find DENC's rationale for its assumed peak seasons to be reasonable, as those seasons represent the critical months that PJM considers to be the peak months from a system operations perspective, when

[2] In the 2014 biennial proceeding, Duke entered into a stipulation with the NC Hydro Group pursuant to which small run-of-river hydroelectric QFs, defined as those with capacity of 5 MW or less, would receive a PAF of 2.0 and 5, 10 and 15-year term options until December 31, 2020. DENC was not a party to that stipulation and does not appear to have any hydroelectric QFs in its service area in this State.

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system emergencies would likely occurs, and when planned outages would not be scheduled. With regard to the Public Staff's proposal to discuss other metrics such as the EOUR, the Commission concludes that the Utilities should evaluate whether another metric, such as EUOR, may be a more appropriate reliability metric to support quantification of the PAF in their initial filings in the next avoided cost proceeding.

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

The evidence supporting this finding is contained in the Initial Statements of DENC and the Public Staff, the initial comments of SACE, the reply comments of DENC, and the entire record in this proceeding.

Summary of the Evidence

In its Initial Statement, DENC explained that in the 2016 Order, the Commission approved DENC's proposal to eliminate the 3% adder that had historically been included in its avoided energy rates, and directed the Utilities in this proceeding to address the effect distributed generation on power flows on their distribution systems as well as the extent of power backflows at substations. DENC presented updated power flow data for its substations for the period September 2016 to August 2018, which it explained supports the continued appropriateness of not including an adder for line losses in the calculation of avoided energy payments to QFs. The updated data showed that transformers with connected solar generation continued to experience backflow and that the number of transformers experiencing backflow has increased since the 2016 Case. Specifically, DENC stated that of the 28 transformers with connected solar generation (compared to 33 in the 2016 study), 16 realized consistent backflow compared to 11 in the 2016 study, and only 2 transformers were shown to have consistent positive flow

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(meaning that they have the capability for additional load reduction) compared to 4 in the prior study. (DENC Initial Statement at 34-35.)

The Public Staff agreed that it is appropriate for DENC to continue to remove the line loss adder from its standard offer avoided costs. The Public Staff noted that DENC demonstrated that the amount of "back feed" from renewable generation occurring and expected to continue to occur on the DENC system justified the continued removal of a line loss adder, but stated that it will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings. (Public Staff Initial Statement at 72-73.)

SACE recommended that DENC re-calculate and add a line loss adder to its avoided cost rates. SACE noted that the Commission recognized the line loss avoidance benefits with siting QFs on the distribution grid closer to load in the Order on Inputs. SACE stated that its consultant, Synapse, reviewed DENC's most recent data and concluded that solar QFs provide line loss avoidance benefits and it is inappropriate to eliminate the line loss adder. SACE claimed that Synapse analyzed DENC's data for 38 substations and found that only two substations experience backflow the majority of the time. SACE recognized that while the historical 3% adder may not reflect the current avoidance benefits QFs are providing in DENC's service territory, it argued that complete elimination of the adder is not appropriate. (SACE initial comments at 19-20.)

In its reply comments, DENC noted that SACE's analysis did not take into account irradiance levels to determine whether a solar QF could generate energy, which means that if it is cloudy or rainy and a solar QF is not generating during a given hour, then the substation will show more hours of positive flow. Including these hours, DENC explained, skewed SACE's analysis in favor of more hours with positive flow, especially

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considering DENC's service territory experienced a higher than normal amount of rainfall during the time period of the analysis. DENC also stated that SACE did not acknowledge the trend over time at several DENC substations for backflows to occur with more frequency as more distributed solar generation is connected to the system. DENC stated that SACE's own analysis and categorization of DENC's transformers with distributed solar generation connected show a majority of the transformers classified as either "neutral" or "negative." Finally, DENC pointed out that SACE did not acknowledge that even when DENC substations are experiencing positive flows, the remaining "room" on the transformer before it will start experiencing backflows is less than 20 MW, and that DENC still has over 200 MW of solar QFs with an executed avoided cost PPA that are not yet operational. (DENC Reply Comments at 42-45.)

Discussion and Conclusions

In the 2016 Order, the Commission acknowledged that distribution line losses are generally only avoided when there is not "backflow" onto the grid, and found that backflowing was occurring "with regularity" on a number of DENC's distribution system circuits. The Commission recognized that this backflow "greatly reduces or eliminates the benefits of the solar QFs line loss avoidances" and found it appropriate for DENC to eliminate the adder from its standard offer avoided energy cost payments. (2016 Order at 91-93.)

Based on the foregoing and the entire record herein, the Commission finds that backflows continue to occur with regularity on a number of DENC's distribution system circuits and are likely, due to the volume of distributed solar generation waiting to connect to DENC's system, to continue to increase over time. As in the 2016 Order, the Commission determines that this development greatly reduces or eliminates the benefits of the solar QFs line loss avoidances. The Commission is not persuaded by SACE that DENC should reinstate the line loss adder for the reasons illuminated in DENC's reply comments. The Commission finds especially important the continuation in the trend toward increased backflow on DENC's system, which will be exacerbated when the significant amount of distributed solar capacity slated to come online in DENC's service area is added to these transformers. The Commission notes as did DENC that while SACE advocated for reinstatement of the adder, perhaps at some lesser amount, it did not offer any suggestion for that amount or how it should be determined. The Commission therefore concludes that its findings on this issue from the 2016 Order with regard to DENC remain supported. It is therefore appropriate for DENC to continue to not include a 3% line loss adder in its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer.

Moreover, we note that DENC has now provided voluminous data in successive avoided cost proceedings demonstrating that the line loss adder should be eliminated from its avoided cost rates. Based on the clear trend shown toward increasing backflow over time shown by the data in these two cases, and on the projected capacity that will come online to DENC's system in the near future, the Commission finds that overall DENC is not likely to see any line loss avoidance from these QFs. There is no evidence to suggest that the trend in increased backflow on DENC will cease; rather, the evidence points to this trend increasing over time. In short, backflows on DENC's system will increase, not decrease, in the future. The Commission therefore also finds that there is no longer a need to continue to require an evaluation of line loss avoidance on DENC's

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system and concludes that DENC should maintain the elimination of the adder from standard offer rates going forward.

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

The evidence supporting this finding is contained in the supplemental and supplemental rebuttal testimony of DENC, Duke, the Public Staff, Ecoplexus, and NCSEA, and the entire record in this proceeding.

Summary of the Evidence

On June 14, 2019, the Commission issued an *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* (Supplemental Testimony Order) in this proceeding directing further evaluation of one of the issues in controversy regarding Duke's modifications to its Standard Terms and Conditions, which included the addition of a proposed Energy Storage Protocol. The Supplemental Testimony Order acknowledged a distinct, yet similar, issue in the proceeding addressing the NC Interconnection Procedure (NCIP) (Docket No. E-100, Sub 101) regarding whether the addition of energy storage facilities to an installed generating facility constitutes a "material modification" under the NCIP. Given the similarity of the issues, the Commission required supplemental testimony be filed to address the following question:

> what avoided cost rate schedule and contract terms and conditions apply when a Qualifying Facility adds battery storage to an electric generating facility that has (i) established a legally enforceable obligation (LEO), (ii) executed a power purchase agreement (PPA) with the relevant utility, and/or (iii) commenced operation and sale of the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

In his supplemental testimony DENC witness Billingsley clarified that DENC's Schedule 19 tariffs or PPAs do not specifically address the three scenarios presented by the Supplemental Testimony Order. He testified that DENC also has not received any proposals to add battery storage to a QF in any of the scenarios and, given the lack of substantive discussions DENC has had regarding adding battery storage to a QF, it did not propose changes to the Schedule 19 tariffs or PPAs in this proceeding. In response to the Commission's question, witness Billingsley stated that DENC's overall position is that if a QF seeks to add battery storage to a proposed or existing facility that established a LEO or executed a PPA in a previous biennial period, even if it has commenced producing power, the QF would be required to establish a new LEO and execute a new PPA in the current biennial period at current rates and contract terms. He argued that a QF in any of the three scenarios presented should not be able to increase its capacity (MW), increase its energy (MWh) production capability, or shift its generation profile under previously established rates and terms. (Tr. Vol. 5 at 57-59.)

Witness Billingsley explained that allowing a QF entitled to rates and terms associated with a previous biennial period to either expand its maximum capacity, energy production, or shift its hours of production under those rates and terms would burden DENC and its customers with newly-obligated overpayments at stale avoided cost rates in contravention of PURPA. He presented evidence that the rates established in the 2012 and 2014 avoided cost proceedings are much higher than the current forecast of avoided cost, which could expose DENC and its customers to millions of dollars of additional payments. Witness Billingsley testified that nearly all of the solar QFs that executed PPAs with DENC during the 2012 and 2014 periods elected the Option B peak hours definition and pricing, which is no longer available. He explained that if one of those QFs can take advantage of Option B pricing for a new battery, it will likely shift its

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Sep 04 2019

output from off-peak to on-peak hours to maximize profit, and thereby conceivably receive approximately $11/MWh more for energy by shifting its production profile, plus $86/MWh for capacity. He argued that this result would inequitably burden DENC and its customers with additional above-market payments. Finally, witness Billingsley stated that as a general principle a QF should not be permitted to expand its scope beyond what was originally agreed upon through a previously established obligation or PPA based on the QFs characteristics as described in the QFs FERC self-certification, CPCN application, or Reports of Proposed Construction. (Tr. Vol. 59-63.)

In his supplemental testimony, Duke witness Snider argued that a "committed" QF proposing to integrate battery storage should not be allowed to do so without the utility's consent (if a PPA exists) and, in all three scenarios presented by the Commission, should enter into a new or modified PPA at Duke's then-current avoided cost rates consistent with North Carolina's current PPA implementation framework. (Tr. Vol. 2 at 163-165.)

Public Staff witness Metz testified that battery storage has the potential to be an important resource when paired with intermittent resources, such as solar QFs, but acknowledged the challenge for Utilities and the Commission in allowing existing and future solar QFs to install and operate battery technology in a way that is fair to ratepayers. Witness Metz agreed with the Utilities that a QF "seeking to add any additional energy output for the grid as a result of the addition of battery storage" should be compensated for the additional energy at the current avoided cost rates in effect when the QF commits to sell the additional energy to the utility. He explained that paying QFs for additional energy at old avoided cost rates would be unfair to ratepayers, as the

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Sep 04 2019

ratepayer would no longer be indifferent between energy supplied by a QF and energy generated by the utility. He disagreed with the Utilities' position that a QF should lose its eligibility for the rates it established for the original solar QF facility without battery storage. Witness Metz recommended that the Commission evaluate in greater detail the engineering and technical challenges, impacts on the interconnection queue, and applicable commercial terms and conditions involved in determining when and how to pay different rates to a QF for existing generation output and additional energy output. He explained that some of the challenges include operational requirements to provide the utility with "sufficient control" over the operation of the QF equipped with battery storage, and how the Utilities plan to efficiently study the addition of energy storage at existing generation sites pursuant to the Commission's order in Docket No. E-100, Sub 101. Specifically, he recommended a working group between developers, Utilities, and other interested stakeholders to review the technological implementation of measuring co-located battery output, and to develop a potentially deployable solution or to further identify specific challenges that would prevent the commercial viability of adding energy storage to existing facilities. (Tr. Vol. 6 at 329-338, 342-343, 346-347.)

In her supplemental testimony, SACE witness Glick testified that pursuant to FERC precedent, battery storage is eligible for QF status. Witness Glick asserted that if the QF discharges electricity to the grid consistent with PURPA and the QF's interconnection agreement, and does not surpass its current AC generating capacity, the QF should be permitted to operate with storage under its existing contract as the utility has "no reasonable basis" to regulate the operation of components on the QF side of the meter. (Tr. Vol. 6 at 273-274.)

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Witness Glick also testified regarding specific generation and production profile issues related to QFs with battery storage. She acknowledged that a QF with battery storage can "easily shift output and will likely discharge some or all of the electricity generated to the grid during the hours when it receives premium pricing" or otherwise structure its battery output in order to "maximize [the QF's] profit." She claimed that more granular pricing and rate design would help improve the value provided by battery storage and disagreed with Duke that adding battery storage to solar QFs on their existing rates will increase system costs. Instead, witness Glick asserted that battery storage will decrease operation costs by reducing the need to run expensive resources during peak demand or build new large capital projects, and battery storage can also provide ancillary services needed to operate the grid. Finally, she made a number of recommendations specific to Duke and then recommended that "Dominion Energy follow all the above recommendations." At the hearing, witness Glick clarified that these recommendations would only apply to DENC to the extent DENC has proposed a document or protocol relevant to witness Glick's recommendations for Duke. (Tr. Vol. 6 at 276-284, 293-94.)

NCSEA witness Norris testified broadly about the importance of market access for energy storage and the potential value of adding battery storage to solar QFs. Witness Norris claimed that energy storage, which he termed a nascent technology, could enable a more affordable, reliable, and sustainable electricity system and noted that HB 589 required a study on energy storage policies and recommended policy changes to consider to address a statewide coordinated energy storage policy. Witness Norris proposed a "compromise position" whereby if a QF seeks to add energy storage to a "committed" generating facility, then the output from the storage equipment would be eligible for the

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then-available avoided cost rate schedule while the output of the existing facility without storage would retain the terms and conditions of the original PPA. Finally, he disagreed with DENC that a QF should not be able to deviate from its configuration or output as specified in the QF's CPCN or FERC Form 556 without losing its LEO. (Tr. Vol. 6 at 123-129, 142-148.)

Ecoplexus witness Wallace agreed that it would be reasonable for the portion of a QF that adds battery storage to enter a new or modified PPA. He testified that the Public Staff's suggestion that additional output from the facility be separately metered and compensated at then-current avoided cost rates and terms without requiring the existing facility to give up its contracted payments is an appropriate and feasible means of balancing the need to incentivize new technology with establishing appropriate rates that reflect their value. Witness Wallace elaborated on various methods to separately meter these outputs and identified the need for further discussion regarding metering and communications as well as commercial PPA terms. He proposed a timeline for review of these topics resulting in a formal proposal to the Commission within 150 days. (Tr. Vol 5 at 345-351.)

In his rebuttal testimony, DENC witness Billingsley testified that given DENC's lack of experience with batteries and the short amount of time available to consider these issues in this proceeding, he believed DENC's original position on this question to be reasonable. He added that based on continued consideration, DENC believes that allowing the existing solar generation facility to continue to receive the original rates for which it was eligible, while applying the current rates to the output from the battery addition, appears to be a reasonable approach to the question posed by the Commission.

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Sep 04 2019

Witness Billingsley also, however, agreed with the Public Staff that there are a number of technical and commercial challenges that would likely arise with the implementation of battery storage at existing QF sites, and stated that these issues would need to be thoroughly studied and addressed before the "compromise" approach could be fully implemented. (Tr. Vol. 5 at 68-70.)

Witness Billingsley also stated the DENC is taking steps to increase its knowledge and understanding on the topic of battery storage, and noted that pursuant to the Virginia Grid Transformation and Security Act, DENC is in the early stages of pursuing a battery storage pilot that will increase its understanding of and experience with batteries and any benefits, costs, or challenges associated with this technology. He testified that DENC would be willing to participate in a working group on this topic, if found appropriate by the Commission, but cautioned that any timelines or milestones associated with such a group allow sufficient time to thoroughly consider these complex issues. (Tr. Vol. 5 at 69-70.)

Witness Billingsley also clarified in response to witness Norris that in referencing the QF CPCN and FERC Form 556 he was not making a legal argument, but instead was presenting the general principal that a QF should not remain eligible for outdated avoided cost rates for significant modifications it makes to its facility beyond that which was originally contemplated by DENC's interconnection studies and the original PPA. He stated DENC's general agreement that QFs should be able to make modifications to their facilities where for example equipment is replaced with like-kind equipment to maintain the original design and capabilities of the facility. (Tr. Vol. 5 at 71.) At the hearing, he emphasized that many existing QF PPAs were executed in the 2013-2015 time frame,

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Sep 04 2019

when energy storage was not contemplated for these facilities. (Tr. Vol. 5 at 85-86.) He also noted his awareness that QFs amend FERC Form 556 or CPCNs, but stated that in his experience these are generally changes that do not affect the administration of the PPA, such as changes in upstream ownership or other minor changes. (Tr. Vol. 5 at 87.)

Finally, Witness Billingsley responded to witness Glick's statement that rates to QFs would not change as a result of adding batteries to existing facilities, but only the total payments to the QF would change. Witness Billingsley explained that this was DENC's exact concern as payments, based on stale rates, would increase, payments would no longer represent DENC's avoided cost or premium peaks, and these over-payments would ultimately be shouldered by customers. (Tr. Vol. 5 at 72-73.)

In Duke's Joint supplemental rebuttal testimony witness Snider disagreed that the addition of storage to operating QFs will inherently create benefits for consumers and stated that even under the compromise position no inherent consumer benefits are created as, at best, customers are left indifferent with respect to whether a QF adds storage to its facility. Witness Snider also testified that consistent with HB 589 any QF proposing a modification to its PPA, by for example adding battery storage, should be expected to offer additional benefits to consumers as consideration to justify the modification. Finally, witness Snider stated his potential concern with the Public Staff's position that the Utilities should pay for "additional energy" from QFs as this could potentially lead to an overpayment inconsistent with PURPA. (Tr. Vol. 2 at 181-191.)

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Discussion and Conclusions

In the Supplemental Testimony Order, the Commission asked parties to address

> what avoided cost rate schedule and contract terms and conditions apply when a Qualifying Facility adds battery storage to an electric generating facility that has (i) established a legally enforceable obligation (LEO), (ii) executed a power purchase agreement (PPA) with the relevant utility, and/or (iii) commenced operation and sale of the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

The Commission is persuaded by the testimony offered by the Utilities and the Public Staff that permitting a QF to receive rates and terms associated with a previous biennial period for additional output from a newly added battery would unfairly burden the Utilities and their customers with newly-obligated overpayments at stale avoided cost rates in contravention of PURPA's requirement that utilities not pay more than avoided cost for QF output. Notably, testimony offered by NCSEA and Ecoplexus recognizes the reasonableness of this approach. The Commission therefore concludes that a QF should not receive rates and terms associated with a previous biennial period for output produced by a newly added battery.

Based on all of the testimony offered on this topic, the Commission also finds that the "compromise" position suggested by NCSEA, which is generally consistent with the testimony of the Public Staff and Ecoplexus, and which would allow a QF to receive original rates and terms for its underlying solar PV facility and to receive current rates and terms for the output from a newly installed battery, has the potential to provide a reasonable approach to the specific question of which rates and terms apply to which source of power. However, this specific issue does not exist in a vacuum. As the Public Staff and the Utilities showed, there are a number of technical and commercial issues to be identified, evaluated, and worked through prior to establishing any standard approach to be used going forward. The testimony of Ecoplexus witness Wallace, while presenting helpful information regarding metering options for adding storage to existing facilities, also identified issues that require evaluation. Additionally, as clarified by DENC at the hearing, this is not a simple matter of changing upstream owners or even increasing the number of panels in a project. Rather, and as shown by witnesses Metz and others, it is a fundamental change to a QF facility that has implications for interconnection, metering, and other commercial terms. Moreover, the testimony offered by SACE witness Glick demonstrates the interest of QFs in "maximizing value," which may often be at odds with the Utilities' interest, and with the PURPA requirement, that utilities not pay more than their avoided cost for QF power. The Commission notes as it has in previous orders that while Utilities are required to purchase QF output, they are not required to guarantee any level of income or return for QF developers.

The Commission recognizes that the issues surrounding the addition of battery storage to existing QFs are likely to arise with increased frequency in the future as battery technology advances, and that these issues are relevant to these avoided cost proceedings as well as others including the periodic proceedings to evaluate the NCIP. Other than finding that a newly added battery should not receive rates and terms associated with a previous biennial proceeding, however, there is not sufficient evidence presented in this record to make further conclusions at this time. The Commission recognizes that this issue was raised fairly late in the proceeding and that its reach is broader than avoided cost. The Commission therefore concludes that a working group should be convened to address this set of issues. The working group should involve

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Sep 04 2019

developers, Utilities, and other interested stakeholders and should consider the technical and commercial questions associated with adding energy storage to existing QF generation facilities, including the rates and terms that will apply but also practical questions such as metering capabilities. Given the complexity of the issues to be evaluated, the Commission finds the schedule proposed by Ecoplexus to be infeasible, and therefore directs the Utilties to address this topic further in their Initial Statements in the next biennial avoided cost proceeding, based on the working group effort.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

This finding is essentially uncontroverted. The Commission concludes that the rate schedules and standard contract terms and conditions proposed in this proceeding by DENC should be approved, except as otherwise discussed herein. DENC should be required to file new versions of its rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. They should be allowed to go into effect 15 days after they have been filed. DENC's filings should stand unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

IT IS, THEREFORE, SO ORDERED, as follows:

1. That the Utilities shall continue to offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all QFs contracting to sell one MW or less capacity. The standard levelized rate option shall include a condition making contracts under those options 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

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Sep 04 2019

consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration;

2. That 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 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. 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

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Sep 04 2019

derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's Sub 106 Order;

4. That DENC shall recalculate its avoided energy rates based on the rate design agreed to by DENC and the Public Staff;

5. That DENC shall recalculate its avoided capacity rates based on a seasonal allocation of capacity costs of 45% summer, 40% winter, and 15% shoulder;

6. That DENC shall use for purposes of this proceeding a PAF of 1.07 in its avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and shall evaluate whether another metric, such as EUOR, may be a more appropriate reliability metric to support quantification of the PAF in its initial filing in the next avoided cost proceeding;

7. That continuing and going forward DENC's standard offer avoided cost payments to QFs on its distribution network should not include any adder for line loss;

8. That the Utilities, the Public Staff, and other interested stakeholders shall engage in a working group to study the technical and commercial issues related to the addition of battery storage to QF facilities and the Utilities shall reflect the results of that effort in their initial filings in the next avoided cost proceeding;

9. That the rate schedules and standard contract terms and conditions proposed by DENC is this proceeding are approved, except as otherwise discussed herein; and

10. That DENC shall file new versions of its rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy

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Sep 04 2019

of the calculations and conformity to the decisions herein are filed within that 15-day period.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of ________________, 2019.

NORTH CAROLINA UTILITIES COMMISSION

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Sep 04 2019

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *Proposed Order*, as filed in Docket No. E-100, Sub 158, were served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 4th day of September, 2019.

/s/Nicholas A. Dantonio

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