NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

June 22, 2017

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 148

Dear Ms. Jarvis:

In connection with the above-captioned docket, I transmit herewith for filing the Public Staff's Proposed Order.

Pages 43, 93 and 94 of the proposed order contain confidential information. By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. The confidential pages will be provided to those parties that have entered into a confidentiality agreement with Duke Energy Progress, LLC and Duke Energy Carolinas, LLC.

Yours very truly,

Electronically submitted
s/ Tim R. Dodge
Staff Attorney
tim.dodge@psncuc.nc.gov

Attachment

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	)))	PROPOSED ORDER OF THE PUBLIC STAFF

HEARD: Tuesday, February 21, 2017, at 9:00 a.m., Tuesday, April 18, 2017, at 9:30 a.m., Wednesday, April 19, 2017, at 9:30 a.m., Thursday, April 20, 2017, at 9:30 a.m., and Friday, April 21, 2017, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC:

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For Carolina Utility Customers Association:

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For Southern Alliance for Clean Energy:

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For Carolina Industrial Group For Fair Utility Rates I, II, and III:

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For NTE Carolinas Solar, LLC:

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For North Carolina Electric Membership Corporation:

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For the Using and Consuming Public:

Jennifer T. Harrod, Special Deputy Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

Tim R. Dodge, Lucy E. Edmondson, Heather D. Fennell, and Robert B. Josey, Jr., Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: This is the 2016 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C.A 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings also are held pursuant to G.S. 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in 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 the purchase and sale of electric power by

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[1] Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30, 128 (1980). See also 45 Fed. Reg. 12, 214 (1980).

electric utilities to cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

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

The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and made determinations regarding other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also 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. The definition of the term "small power producer" for purposes of G.S. 62-156 is more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) includes only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding power producers using other types of renewable resources.

On June 22, 2016, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing. Pursuant to the Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); Western Carolina University (WCU); and New River Power and Light Company (New River) were made parties to these proceedings.

The following parties filed Petitions to Intervene that were been granted by the Commission: North Carolina Sustainable Energy Association (NCSEA); Public Works Commission of the City of Fayetteville; Carolina Utility Customers Association, Inc.; Carolina Industrial Groups for Fair Utility Rates I, II, and III; Southern Alliance for Clean Energy (SACE); Strata Solar, LLC; North Carolina Pork Council; NTE Carolinas Solar, LLC; Cypress Creek Renewables, LLC (CCR); O_2 EMC, LLC; and North Carolina Electric Membership Corporation. Participation of the Public Staff was recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e}. Pursuant to G.S. 62-20, the North Carolina Attorney General's office gave notice of intervention on April 11, 2017.

On November 15, 2016, DNCP filed its Initial Comments and Exhibits. DNCP amended its avoided cost information on November 16, 2016, with corrected on-peak load numbers. Additionally on November 15, 2016, DEC and DEP (collectively, "Duke") filed a Joint Initial Statement and exhibits. On November 28, 2016, WCU and New River filed proposed avoided cost rates. On December 20, 2016, NCSEA filed a Motion to Strike as irrelevant to the proceeding certain materials in the proposals of DEC, DEP, and DNCP. An Order denying NCSEA's motion was subsequently issued on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule. On December 30, 2016, the Commission issued an Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, and setting the evidentiary hearing.

On January 17, 2017, DEC and DEP filed confidential avoided cost information.

On or before February 15, 2017, all electric utility companies filed Affidavits of Publication of Notice of Hearing, and the public hearing was held on February 21, 2017, as scheduled. Twelve witnesses gave testimony at the public hearing.

On February 21, 2017, DNCP filed the direct testimony of J. Scott Gaskill and Bruce Petrie. Additionally on February 21, DEC and DEP filed the testimony with exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman, III, and Gary Freeman.

On March 28, 2017, NCSEA filed the testimony and exhibits of Carson Harkrader, Ben Johnson, and Kurt Strunk; CCR filed the testimony of Patrick McConnell; and SACE filed the testimony and exhibits of Thomas Vitolo, Ph.D. On the same date, NCEMC filed initial comments. The Public Staff filed direct testimony and exhibits of John Hinton, Jay Lucas, and Dustin Metz.

On April 8, 2017, DNCP filed the rebuttal testimony of witnesses Gaskill and Petrie, and DEC and DEP filed the rebuttal testimony of witnesses Bowman, Snider, Holeman, and Freeman.

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

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DNCP to be required to offer long-term levelized capacity payments and energy payments for five, ten, and 15-year periods as standard options to hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should 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 consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration.

2. It is appropriate for DEC, DEP, and DNCP to be required to offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs contracting to sell one MW or less capacity. The standard ten-year levelized rate option should include a condition making contracts renewable for subsequent terms at the option of the utility on

substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration.

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

but shall instead change as determined by the Commission in the next biennial proceeding.

4. DNCP should continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in the 2006 biennial avoided cost proceeding in Docket No. E-100, Sub 106 (Sub 106 Order).

5. For the purposes of this biennial proceeding, when calculating avoided capacity rates using the peaker method, it is appropriate to include a capacity credit in years of a utility's integrated resource planning (IRP) forecast period when a capacity need is demonstrated during that period.

6. It is appropriate for the utilities to continue to evaluate the capacity benefits of QF generation and to make other changes as needed to accurately reflect the avoided capacity benefits provided by QF generation of all resource types over the short and long run.

7. The availability of a combustion turbine (CT) is not determinative for purposes of calculating a Performance Adjustment Factor (PAF) because the fixed costs of a peaking unit under the peaker methodology employed by the

Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

8. A PAF of 1.16 should be utilized by DEC, DEP, and DNCP (for its Schedule 19-FP) in their respective avoided cost calculations for all QFs except hydroelectric facilities without storage capability or any other type of generation.

9. A PAF of 2.0 should be utilized by DEC, DEP and DNCP (for its Schedule 19-FP) in their respective avoided cost calculations for hydroelectric QFs without storage capability or any other type of generation until discontinued in accordance with the stipulation filed by DEC, DEP, and the NC Hydro Group and the Commission's December 31, 2014, Order in Docket No. E-100, Sub 140 (Sub 140).

10. DEC and DEP should recalculate their avoided capacity rates using seasonal allocation weightings of 60% for winter and 40% for summer.

11. DEC's and DEP's proposal to reset energy prices under the standard offer contract every two years does not provide sufficient fixed long-term rates to allow a QF a reasonable opportunity to be able to seek financing.

12. It is appropriate for the utilities to offer avoided energy and capacity rates that are fixed for the length of the standard contracts.

13. It is appropriate to require DEC and DEP recalculate their avoided energy rates using forward natural gas prices for no more than five years before

transitioning to their fundamental forecasts for the remainder of the planning period.

14. To the extent the utilities wish to change the terms of forward prices and long-term forecasts used in avoided cost calculations, it is appropriate to require that these changes first be proposed and approved in the utilities' biennial IRP proceeding, before modifying the approach used in their biennial avoided cost filings.

15. It is appropriate for DNCP to make locational energy pricing adjustments to its avoided energy rates.

16. An imminent violation of a North American Electric Reliability Corporation (NERC) BAL Standard is a system emergency, as defined in 18 CFR 292.101(b)(4); therefore, it is appropriate for DEC, DEP, and DNCP to curtail PURPA QFs when a NERC BAL Standard violation is imminent.

17. It is not necessary for DEC and DEP to amend their standard offer contract to incorporate the imminent violation of a NERC BAL Standard into the system emergency provision, since their standard offer contract already allows curtailment of QFs in a system emergency, as defined in 18 CFR 292.307(b).

18. It is appropriate for the utilities to file procedures with the Commission stating how they would curtail QFs on a nondiscriminatory basis in accordance with 18 CFR 292.307 when there is a system emergency.

19. It is appropriate for the utilities to provide reports to the Commission and Public Staff on a quarterly basis, detailing the instances in which they curtailed QFs and reasons for the curtailments, along with data justifying the curtailment.

20. There is significant power backflow on substations in DNCP's North Carolina service territory from solar generation on the distribution grid such that avoided line loss benefits associated with distributed generation have been greatly reduced or negated.

21. It is appropriate for DNCP to eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network.

22. It is appropriate for DEC and DEP to continue to include the line loss adder in their avoided cost payments.

23. It is appropriate for DEC and DEP to study the effects of solar QFs on their distribution grid to determine if there is sufficient backflow at their substations so that they should eliminate the line loss adder from their standard offer avoided cost calculations filed in the next avoided cost proceeding.

24. It is still premature for DEC, DEP, and DNCP to include integration costs and benefits associated with increasing levels of solar generation in their service territories in the calculation of their standard avoided cost rates.

25. In the next biennial avoided cost proceeding, DEC, DEP, and DNCP should propose a solar-specific rate for QFs eligible for the standard contract.

26. For QFs not eligible for the standard offer, it is appropriate for the utilities to incorporate the benefits and costs attributable to a specific technology in the avoided cost rates. Prior to doing so, however, the utilities shall file in this docket a description of the technology-specific adjustments and provide examples of how the calculations would be made.

27. WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved five-, ten-, and 15-year terms to hydro QFs interconnected at distribution that are contracting to sell five MW or less should be approved. The changes the Commission has approved herein to DEC's proposed five-, ten-, and 15-year avoided capacity rates should be reflected in the long-term avoided capacity rates that WCU and New River file in compliance with this Order.

28. WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved ten-year terms to non-hydroelectric QFs interconnected at distribution should be approved. The changes the Commission has approved herein to DEC's proposed ten-year avoided capacity rate for non-hydro QFs should be reflected in the long-term avoided capacity rates that WCU and New River file in compliance with this Order.

29. It is appropriate to add a fourth requirement to the current Commission standard for the establishment of a legally enforceable obligation (LEO) for QFs. Therefore, a QF may establish a LEO when it has (1) self-certified

with FERC as a QF, (2) made a commitment to sell its output to a utility under PURPA using the approved Notice of Commitment Form (NoC), (3) filed a report of proposed construction an (ROPC) or received a Certificate of Public Convenience and Necessity (CPCN) for the construction of the facility, and (4) submitted a completed interconnection request pursuant to the North Carolina Interconnection Procedures (NCIP). For a QF larger than one MW that has been designated as an A or B project in the interconnection queue at the time of its interconnection request, the date on which the commitment to sell is established shall be the earlier of (i) 105 days after the submission of the interconnection request, or (ii) upon the receipt of the system impact study from the public utility. For a QF larger than one MW that has not been designated as an A or B project in the interconnection queue at the time of its interconnection request, the date of the commitment to sell shall be the earlier of (i) 105 days after the project is first designated as an A or B project, or (ii) upon the receipt of the system impact study from the public utility.

30. It is appropriate to require the utilities to modify the NoC to reflect the additional requirement for QFs larger than one MW, and to explain the consequences of withdrawal of a notice of commitment.

31. It is appropriate for the utilities and other interested parties to form a working group to develop procedures for the negotiation of non-standard purchased power agreements (PPAs) for projects above one MW.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 4

The evidence supporting these findings of fact is found in the Joint Initial Statement of DEC and DEP; the Initial Comments and Exhibits of DNCP; the testimony of Duke witnesses Bowman, Freeman, and Snider; the testimony of DNCP witness Gaskill; the testimony of NCSEA witnesses Harkrader, Johnson, and Strunk; and the testimonies of CCR witness McConnell, SACE witness Vitolo, and Public Staff witness Hinton.

DEC's and DEP's Joint Initial Statement provided that while the Commission's policies to implement PURPA have remained relatively unchanged over the past decade, the impact of these policies over the past two years to the utilities, our State's energy grid, and customers has become significant. The Joint Initial Statement provided that:

> Since 2012, an unprecedented surge in utility-scale solar QF generators, including over 200 projects sized between 4.0 to 5.0 MW, have interconnected and are now selling energy to the Companies, especially to DEP, pursuant to Commission approved long-term PURPA avoided cost rates. As of September 30, 2016, the Companies have interconnected more than 1,300 MWs of third-party utility-scale solar generation; importantly, with nearly 75% of those solar projects (960 MWs) interconnected in DEP. More importantly, however, approximately 4,600 MWs of additional utility-scale solar generators have requested to interconnect to the Companies systems in North Carolina.[2]

The Joint Initial Statement noted that the amount of PURPA-supported solar generation currently in development exceeds DEC's and DEP's near-term energy needs in certain hours as well as the projected near term capacity needs presented

[2] Joint Initial Statement at. p. 5.

in their respective biennial 2016 IRPs, which currently indicate that no additional "unplanned capacity is needed to reliably serve customers' peak consumption, or energy demand, through the years 2022 and 2021 respectively."[3]

Duke witness Bowman reviewed the history of PURPA implementation in North Carolina and testified that prior to 1985, standard, levelized avoided cost tariffs from DEC and DEP were available to all QFs for up to 15 years, regardless of size. In Docket No. E-100, Sub 41A, the Commission established a five MW eligibility limit for the standard tariffs. She testified that the Commission, in balancing the interests of QFs, the utilities, and customers, adopted the five-MW standard offer eligibility cap because the default risks associated with smaller QFs were "relatively small in terms of dollar exposure and impact on supply" when compared to those of larger QF projects and because, at that time, these smaller QF projects would "probably not have the resources or the expertise to negotiate a contract with a utility if these standard options were not available."[4] However, she testified that in recent years:

> The 5-MW threshold evolved from a reasonable policy for encouraging development of relatively small QFs to a highly attractive solar development business model for sophisticated and well-capitalized entities from around the country. The majority of developers of solar projects 5 MW and less are no longer unsophisticated "mom and pop" developers, unable to manage negotiating a PPA with the utilities. To the contrary, in recent years, well-experienced, sophisticated, and well-capitalized solar developers have taken advantage of the guaranteed, long-term fixed

[3] *Id.* at 6.

[4] *Order Establishing Levelized Rates for Cogenerated Power and Maintaining Interconnection and Wheeling Policies*, Docket No. E-100, Sub 41A (Jan. 22, 1985).

rates of the standard contract by obtaining LEOs on multiple 5 MW and less solar facilities.[5]

Based on this change, Ms. Bowman testified that the prior justification for the five MW threshold no longer exists, and that based on current economic and regulatory conditions in North Carolina, it was appropriate for the Commission to lower the capacity eligibility limit for standard avoided cost rates from five to one MW. She stated that the one-MW threshold was a reasonable proxy to differentiate between small QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial purposes such as residential customers, retail stores, hospitals, and schools, as compared to larger sophisticated commercial enterprises or power generation developers. She also noted the following factors supporting the one-MW threshold:

- DEC's and DEP's net energy metering tariffs are available to customer-generators with a capacity up to one MW.
- Since 2010, FERC has not required self-certification of QFs below one MW.
- Based on recent experience in processing QF solar interconnection requests, one-MW solar projects are more likely to pass the Section 3 Fast Track Process under the NCIP, which would mean both the PPA and Interconnection Agreement could be obtained in a more standardized and streamlined fashion.

[5] T. Vol. 2, p. 344.

Ms. Bowman testified that lowering the eligibility limit for standard offer rates to one MW would allow the avoided cost rates offered to QFs to be based on a more precise and timely assessment of the costs that a particular QF allows the utilities to avoid, since an increased percentage of projects would have to negotiate avoided cost rates. She further testified that DEC and DEP have gained greater experience in negotiating PPAs with QFs larger than five MW, routinely producing monthly avoided cost calculations for use in negotiated PPAs, along with standardizing the terms and conditions, thereby reducing the time and costs previously associated with bilateral negotiations.

With regard to the maximum contract terms for standard contracts, Ms. Bowman testified that DEC and DEP propose to eliminate the five-year and 15-year standard contract terms and instead use a single ten-year long-term avoided cost contract. The rates would include a fixed, levelized capacity component, but would recognize the capacity value of the QF starting in the first year that a utility's IRP demonstrates a capacity need. The energy rates included in the contract would be updated every two years as part of the Commission's biennial avoided cost proceedings.

Ms. Bowman acknowledged that the Commission has concluded in past biennial proceedings that the 15-year maximum contract struck a balance between encouraging QF development and reducing the utilities' exposure to overpayments because "the facilities entitled to long-term rates are generally of limited number and size." She also noted that while the Commission has declined to eliminate the

15-year standard offer contract in past proceedings, the Commission indicated that it would continually reconsider the requirement "as economic circumstances change from one biennial proceeding to the next." (T. Vol. 2, p. 351). She recommended that the Commission reconsider this requirement because the large number of five-MW solar QFs in the DEC and DEP service territories has resulted in the number of QFs entitled to these long-term contracts no longer being of limited number and size. Therefore, customers faced overpayment risk as the number of solar QFs requesting to sell power under standard avoided cost rates continued to increase.

Ms. Bowman testified that PURPA requires avoided cost rates that are just and reasonable to customers, in the public interest, and not discriminatory to QFs, but it does not prescribe a minimum or maximum term for a long-term contract. She testified that if contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate and no longer mirroring the utility's incremental costs. Thus, long-term contracts with forecasted rates shift the risks of those rates not aligning with avoided costs to the utilities' customers, and this risk grows as more QFs utilize these longer-term rates. She testified that a number of other states have terms shorter than North Carolina's current terms, including South Carolina (ten years), Georgia (five years), Idaho (two years), and several with one year terms, including Tennessee, Alabama, and Mississippi. Ms. Bowman further testified that while FERC in its Order No 69 stated that "in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out," FERC was assuming that QF development would remain constant regardless of avoided cost rates and regulatory circumstances. She stated that has not been the case in North Carolina, as evidenced by the recent surge in QF development in recent years.

Ms. Bowman also testified regarding the Stipulation of Settlement ("Hydro Stipulation") that DEC and DEP entered into with the North Carolina Hydroelectric Group in the Sub 140 proceeding. She stated that consistent with the direction in G.S. 62-156 to "encourage . . . [and] enhance the economic feasibility" of hydro QFs, the Hydro Stipulation, which expires December 31, 2020, provides that DEC and DEP will maintain certain pre-existing avoided cost policies for run-of-river hydroelectric QFs that are five MW and less, including the option of five-, ten-, and 15-year contract terms.

In its November 15, 2016 Initial Comments, DNCP proposed five major adjustments to its standard offer contracts and rate schedules:

1. Reduce the threshold at which a QF qualifies for the standard rates and contract terms from five to one MW.
2. Eliminate the 3% line loss adder from its proposed avoided energy cost rates.
3. Adjust its avoided cost energy rates to reflect the locational energy value of its North Carolina service area as opposed to the entire PJM Dominion Zone (or DOM) Zone.

4. Set the avoided capacity rate to zero to reflect its position that additional solar QFs in North Carolina will not enable DNCP to avoid additional capacity costs in either North Carolina or elsewhere on its system.
5. Reduce the maximum standard QF contract term from 15 years to ten years.

DNCP also proposed to continue to offer QFs Schedule 19-LMP as an alternative to its Schedule 19-FP, modified to include payment for delivered energy only at avoided cost rates, as determined by the Commission. Under Schedule 19-LMP, DNCP would pay a QF for delivered energy at an equivalent amount to what it would have paid PJM if the QF had not been generating. The avoided energy rates paid to QFs with a design capacity of greater than ten kW would be the DOM Zone Day-Ahead hourly locational marginal prices (LMP) divided by 10, and multiplied by the QF's hourly generation, while the smaller QFs would be paid the average of the DOM Zone Day-Ahead hourly LMPs for the month as shown on the PJM website.

DNCP witness Gaskill testified that at the time the Commission issued its Order Setting Avoided Cost Input Parameters on December 31, 2014, in Docket No. E-100, Sub 140 (Phase One Order), the amount of solar in DNCP's service area was not substantial: only seven PPAs had been executed totaling approximately 58 MW of solar QF capacity in DNCP's North Carolina territory, and only one of these seven QFs was operating at the time. While DNCP and the Commission were aware of the increased solar QF development activity, it was difficult to predict the speed and magnitude of solar development that would occur in the three years that followed. DNCP now has 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina, of which approximately 350 MW have already commenced commercial operation, and a significant number are pending in DNCP's transmission and distribution interconnection queues. In total, DNCP has approximately 2,800 MW of total active solar projects in its North Carolina service territory. DNCP contrasts that QF generation with its average on-peak load of approximately 518 MW in its North Carolina service territory.

Witness Gaskill testified that DNCP has so much distributed generation from solar that the majority of circuits on which solar QFs interconnect in North Carolina are backflowing onto the transmission grid some portion of every day. He noted that when distributed generation exceeds the load on its respective circuit, many benefits attributed to the distributed nature of the generation, such as reduced congestion, mitigated line losses, and improved local reliability, are lost. Mr. Gaskill testified that three areas of avoided costs are impacted by solar QFs exceeding load: "(1) distribution line losses are not avoided by incremental Solar DG; (2) locational marginal prices (LMPs) in its North Carolina service territory are lower; and (3) incremental QF generation is unable to avoid future capacity costs because there is no longer load to offset." (T. Vol. 5, p. 140). He further testified that solar QFs being added in DNCP's service area in North Carolina are located in a narrowly distributed geographic and electrically-connected location with little load growth, which not only further reduces the proposed benefits of distributed generation, but also leads to increased operational challenges.

Mr. Gaskill also noted the Commission's past recognition that a balance must be struck between the need to encourage QF development and the risks of overpayments and stranded costs. Similar to DEC and DEP, he indicated that DNCP believes that at this time standard rates and contracts for all QFs should be limited to projects with one MW, or less of nameplate capacity. He testified that requiring more QFs to enter into negotiated contracts instead of standard contracts would provide several benefits: (1) avoided costs to which a QF is entitled would align more closely with the QF's LEO, better reflecting current market conditions; (2) rates and terms can be customized to the specific project and location to incentivize projects to locate in areas or on circuits that need new generation; (3) additional customer protections, such as non-levelized rates, can be included in the negotiated contracts; and (4) as the majority of the projects in DNCP's service area have been developed by large, national developers with broad portfolios of renewable generation, access to complex financing, and experience in PPA negotiations, lowering the standard offer eligibility threshold would allow the standard rates to remain available for smaller-scale projects, while reducing customer exposure to risk of overpayment.

With regard to the standard contract term, Mr. Gaskill testified that DNCP also proposes to reduce the maximum term of a standard avoided cost contract from 15 to ten years, such that QFs that qualify for a standard avoided cost contract could sign a PPA with either a five or ten-year term. He testified that the intent of this change is to reduce customers' exposure to potentially above-market payments for QF output that could otherwise result under 15-year contracts. Mr. Gaskill stated that since the fixed, long-term prices provided in avoided costs are based on projections of the future cost of electricity and changes in technology, capital, and fuel costs, there will be a differential between the rates a utility pays for QF output under a standard contract as compared to its actual avoided cost in any given year of that contract. He stated that in recent years, the declines in fuel and equipment prices have resulted in the avoided cost rates approved in 2012 and 2014 being higher than DNCP's current market prices.

Mr. Gaskill testified that DNCP's proposal to reduce the maximum contract term to ten years is consistent with PURPA, since it still provides a basis for long-term financing of the project. He indicated that six of the 12 non-standard contracts that DNCP has entered into with solar QFs ranging from 12 to 20 MW have contained ten-year terms.

CCR witness McConnell testified that, along with the pricing contained in a PPA, credit quality and tenor are the most critical components for a renewable energy project developer to be able to obtain financing. He testified that for the majority of projects, lenders are generally unwilling to lend against uncontracted cash flows, and that absent some sort of third-party credit enhancement (like a government guaranty), he has not seen a loan maturity or amortization for a project under 75 MW extend beyond the term of a fixed-price PPA. He testified that the utilities' proposal to limit the length of standard-offer contracts to ten-year terms would lead to ten-year amortization periods, which will mean less debt and greater sponsor equity requirements at lower returns and greater risk, and in turn will result in fewer projects getting financed and constructed.

Regarding the utilities' proposal to reduce the standard-offer threshold to one MW, Mr. McConnell testified that scale is critical in project, and that reducing the standard offer contract threshold to one MW would make financing projects in North Carolina much more challenging. He testified that much of the financing for five-MW facilities was obtained through grouping a number of projects together into portfolios to create critical mass for debt and tax equity investors. If the standard offer threshold were lowered to one MW, an even larger number of projects would need to be grouped together into a portfolio, and the portfolio size would quickly become unmanageable due to the amount of due diligence required for that number of projects, which would largely shut out the institutional market from financing standard offer contracts.

SACE witness Vitolo testified that the utilities' proposal to reduce the maximum capacity for which renewable QFs are eligible for a standard avoided cost rate structure from five to one MW will have several negative repercussions. First, he noted that the bilateral negotiation process for those facilities that do not qualify for the standard offer contracts are lengthy and resource-intensive, and also take place with a significant power imbalance, since the incumbent utility is generally the QF's only potential customer for its power. Second, he discussed the effect that the reduction in the standard offer contract threshold would have on economies of scale. He stated that while variable costs such as the cost of panels, inverters, and land grow predictably with the size of the project, fixed costs such as legal, administrative, and some engineering costs do not. As such, a larger project has a lower total cost per kilowatt than a smaller project. Reducing the capacity limit for standard avoided cost rates may require the developer either to forego economies of scale that were otherwise available at the previous five-MW threshold and instead build a smaller project to avoid the costs and risks of negotiation, or to retain the economies of scale of the larger project but also bear the cost and risk of a bilateral negotiation.

Dr. Vitolo also testified that reducing the eligibility for a standard offer contract could increase the number of projects under development, thereby adding additional stress on utility interconnection queues and the resources that the utilities have available to conduct bilateral negotiations.

With regard to the proposals by DEC, DEP, and DNCP to reduce the maximum contract duration for which renewable QFs are eligible under the current avoided cost tariffs from 15 to ten years, Dr. Vitolo testified that project financing could be jeopardized and the proposals may therefore violate PURPA. In addition, reducing the standard offer contract duration results in differential treatment between QF solar projects and utility solar projects. He stated that the QF industry in North Carolina has demonstrated a clear ability to finance five-MW solar QFs with 15-year contracts, and that the utilities have shown that some larger facilities have been built with ten-year contracts. Dr. Vitolo cautioned, however, that this doesn't necessarily indicate that smaller projects would also be able to obtain financing relying on a ten-year PPA. In addition, he noted that the proposed reductions in avoided energy and capacity rates to the rates approved in the 2014 proceeding may make it difficult for any facilities, large or small, to be financed for ten-year durations.

Dr. Vitolo also noted that each of the utilities have solar photovoltaic (PV) facilities in rate base, with recovery periods extending from 20 to 35 years. He noted that similar to a longer loan reducing monthly payments, a longer depreciation schedule allows for a reduced near-term rate impact, therefore making the investment more attractive. This differential treatment between the cost recovery provided for utility solar projects and QF generation is also problematic. Dr. Vitolo recommended that, at a minimum, the Commission maintain current policy by requiring DEC, DEP, and DNCP to allow renewable QFs to continue to make standard offer terms available for at least 15 years, and the Commission consider requiring the utilities to offer solar QFs fixed contracts at lengths that match the recovery period of the respective utility's own PV assets.

NCSEA witness Johnson testified that he reviewed the adjustments to the standard offer contract thresholds and terms proposed by the utilities and found that all of the proposals have the effect of increasing the risks faced by QFs and making it more difficult to finance QF projects. He further testified that the utilities have highlighted the challenges they face or may face as a result of distributed generation, but provided little information as to the corresponding benefits, such as increased geographic and fuel diversity and reduced exposure to fuel price volatility. He also testified that the utilities did not propose changes to their avoided cost tariffs to send more precise price signals, encourage QF investment where it will be most beneficial, or minimize risks and maximize benefits for ratepayers over the long run.

With regard to the utilities' proposal to reduce the five-MW ceiling for the standard offer tariff to one MW, Dr. Johnson testified that there were some potential benefits to this approach, such as realizing more benefits of distributed generation by siting it in urban areas, but that overall, the adjustment was too significant a change without additional thought being given to the potential for unintended consequences. He testified that his main concern was that many QFs would be reluctant to engage in costly, time-consuming negotiations with the utilities, which may force them to stay within the familiar terrain of the standard offer tariff, potentially increasing the number of projects that are moving through the queues. Instead, Dr. Johnson stated that if the Commission chose to modify the threshold, it should consider a smaller adjustment, such as to 3.75 MW or four MW. He also recommended that the Commission reconsider this issue again in the next biennial proceeding.

NCSEA witness Harkrader testified that in her experience as a solar developer in North Carolina, the 15-year standard offer contract coupled with the fixed rate over the entire contract term has been critical to enabling QFs to attract capital. She testified that lenders typically require a fixed-rate PPA to provide certainty with respect to revenue stream, and a sufficient term to allow for repayment of the entire debt. She stated that the 15-year contract term has enabled a capital structure that is affordable to the QF developer and, therefore, has encouraged QF development. In turn, the certainty provided by the standard offer contract has provided the stability necessary to encourage QF development in recent years, as well as to drive down the cost of developing solar facilities. She testified that adopting the utilities' proposed modifications would abruptly curtail the QF market that has been created in North Carolina.

Ms. Harkrader testified that DEC and DEP have recently reduced the PPA term they offer to QFs for negotiated PPAs. Because of this change, she is concerned that the combined effect of the reduction of the standard offer threshold and the changed terms for negotiated contracts would not allow QFs a reasonable opportunity to attract capital. She stated that NCSEA did not support any of the utilities' proposed changes to the standard offer.

NCSEA witness Strunk testified that the utilities' proposed changes to reduce the standard PPA term to ten years and to require the adjustment of avoided energy rates every two years would not provide QFs with a reasonable opportunity to attract capital from investors. He testified that these changes compress the recovery of capital investment in long-lived generation assets into a period too short to allow QFs to attract capital on reasonable terms.

Public Staff witness Hinton testified that the Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by FERC regulations, and while it has previously rejected efforts by the utilities to lower the threshold for renewable QFs, it has also rejected efforts to increase the maximum cap for eligibility for the standard contract. He noted that in the Phase One Order, the Commission stated that it "must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers, and found that increasing the maximum cap for eligibility for the standard contract may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers." (T. Vol. 8, p. 55).

Mr. Hinton testified that in the Sub 140 proceeding, the Public Staff noted that "setting the standard above the minimum threshold required under PURPA allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale, while providing ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options available." (T. Vol. 8, p. 56). However, the Public Staff also recognized the significant level of QF development in North Carolina since the passage of S.L. 2007-397 (commonly referred to as Senate Bill 3) and the number of proposed QFs at or near the five-MW standard threshold. The Public Staff expressed concerns about the challenges faced by QFs not eligible for the standard offer rates seeking to negotiate with the utilities, and instead recommended that the Commission maintain the five-MW standard threshold, finding that it represented an appropriate balancing point.

Mr. Hinton testified that since the Sub 140 proceeding, the significant growth in the number of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers, and that the higher penetration of resources was posing operational and technical challenges to the utilities. As such, he testified that it is appropriate for the Commission to consider modifications to the standard offer threshold.

Mr. Hinton recommended that the Commission reduce the standard offer threshold from its current five-MW level to a level that more currently reflects current conditions in the QF marketplace and better protects ratepayers from the risk of overpayment. Mr. Hinton evaluated several relevant regulatory thresholds, including the following:

- G.S. 62-110.1(g) exempts nonutility-owned generating facilities fueled by renewable energy resources less than two MW in capacity from having to obtain a CPCN from the Commission.
- Section 3 of the NCIP allows facilities up to two MW to be eligible for the Fast Track Process, regardless of location.
- The Commission in its March 30, 2009, *Order Amending Net Metering Policy* in Docket No. E-100, Sub 83, established one MW as the maximum size of a facility in North Carolina eligible to net-meter. This position was also guided in part by G.S. 62-133.8(i)(6), which directed the Commission

to consider in its adoption of rules "whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less."

- As pointed out by Duke witness Bowman, FERC has not required QFs below one MW to self-certify as a QF since 2010.

Mr. Hinton testified that he agreed with Ms. Bowman that there are also some practical reasons for supporting a reduction in size to one MW, including, in particular, the reduced likelihood of a facility between one and two MW passing the Fast Track Process. He also agreed with Duke witness Bowman and DNCP witness Gaskill that the reduced threshold would result in more QFs being offered avoided cost rates based on more timely information, including updated capacity needs, fuel costs, and other factors that may reduce the exposure of ratepayers to potential overpayment due to changing market conditions.

NCEMC indicated in its verified comments that in its role as a customer, it purchases significant amounts of power from the utilities and has concerns about cost increases from the increase in solar development and the potential for "pass-through" of costs related to energy and capacity costs to comply with PURPA or to solar integration costs. In addition, NCEMC also commented that it depends on the utilities' bulk power services, and that over-generation events in the DEP Balancing Area (BA) could potentially present reliability challenges resulting in congestion at a transmission level that would threaten system reliability and its ability to serve its customers. As such, NCEMC requested the Commission to evolve its existing PURPA policies to avoid these increased costs and system impacts.

In her rebuttal testimony, Duke witness Bowman disagreed with NCSEA witness Johnson's concerns that the utilities' proposal was intended to stop solar development in North Carolina, but was instead designed to continue solar development in a smarter, more sustainable way. She stated that no party contended that the utilities' proposal violated PURPA, and noted that the Public Staff also agreed with the utilities' proposal to adjust the standard offer eligibility threshold to one MW, based on current economic and regulatory circumstances. Regarding the concern raised by SACE witness Vitolo that lowering the threshold would potentially result in an increase in the number of smaller projects, exacerbate the delays already being experienced in the interconnection queue, and add costs, she stated that eliminating the incentive to arbitrarily develop five-MW solar projects based on the standard offer threshold may, in fact, improve economies of scale if solar developers transition to developing larger projects. Regarding the power imbalance issue raised by Dr. Vitolo, Ms. Bowman testified that the majority of utility-scale solar project developers are no longer unsophisticated, small developers, and highlighted that six developers account for more than 65% of the standard offer projects in DEC and DEP's combined interconnection queues.

In response to the concerns raised about the time and expense associated with the negotiated PPA process, witness Bowman indicated that DEC and DEP have developed more standardized PPA terms and conditions for larger QFs to help streamline the negotiation process and now routinely produce updated monthly avoided cost calculations for these negotiated PPAs. She noted that in the context of an uncontested PPA, DEC and DEP require approximately 25 hours of staff time to develop an updated avoided cost calculation and to negotiate an uncontested PPA. She also noted the intention of DEC and DEP to further streamline and standardize the process to reduce transaction costs and time associated with negotiating a PPA. She reiterated that the Commission has provided guidance on the issues to be considered in negotiations, as well as the importance of using the most up-to-date data to determine the inputs for negotiated rates.

Regarding SACE witness Vitolo's argument that the Commission should consider mandating the utilities to offer fixed contracts that match the longer recovery period of the solar PV and other generating assets owned by the utilities, Ms. Bowman noted the differences between QF contracts and generation from utility-owned assets, including the following: (1) utility resource additions are driven by need, and a utility is not able to recover the costs until after the Commission approves a CPCN determining the facility is the least-cost resource to fill the utility's need, whereas PURPA requires utilities to reimburse QFs for selling power whether or not the power is needed; (2) utility load-following generating resources are dispatchable and can be backed down when more economic alternatives are available; (3) because utilities are not locked in to long-term fixed contracts, they can pass lower fuel and other operating costs savings to customers, but a utility does not have the ability to dispatch or back down a QF when more economic alternatives are available; and (4) avoided cost rates that QFs are entitled to receive are not related to the cost of the PURPA project, whereas capital costs of utility generating assets are determined based upon their specific cost and recovered over their depreciable useful lives.

Duke witness Freeman also testified in response to SACE witness Vitolo's assertion that the reduction in the standard offer contract size would increase the number of projects under development and therefore add further projects for review to the interconnection queue, which already has a significant number of projects pending. Mr. Freeman testified in the unlikely event that the reduction in size resulted in a large increase in smaller projects, the small QF projects are more likely to be eligible for and pass the NCIP Fast Track Process, which provides a more streamlined process for interconnection.

In his rebuttal testimony, DNCP witness Gaskill responded to the claims by CCR, NCSEA, and SACE witnesses that reducing the capacity thresholds for the standard contract from five to one MW would impact a QF's ability to finance some projects. He testified that the developers in North Carolina tend to be large and well-capitalized with large portfolios of generation projects in North Carolina and around the country. He also noted that NCSEA witness Strunk and CCR witness McConnell testified that they commonly group together multiple small projects in order to improve the financing terms of a larger portfolio. He testified that he believes "the market would be better served by removing the incentive to break up the projects into small increments." He stated that

> [DNCP] believes the intent of the standard offer contract is to provide simplified and standard market access for the truly small developers - it is not intended as a means for a large developer to break up large solar deployments into small individual projects simply to get higher pricing and better financing terms, which in my opinion is occurring now in North Carolina.[6]

Responding to SACE witness Vitolo's testimony, Mr. Gaskill testified that reducing the standard offer size would ultimately realize a positive benefit to developers, utilities, and customers by reducing the overall number of small contracts and negotiations and instead providing a better signal to developers to build larger projects that more fully utilize economies of scale. Similar to Duke, DNCP has developed standardized large contracts that provide a template for negotiated contracts to improve the efficiency of negotiated transactions. He also indicated that DNCP has successfully negotiated contracts with 12 QFs totaling 214 MW.

Regarding the reduction in standard offer contract terms from 15 to ten years, Mr. Gaskill noted that DNCP has executed a number of negotiated contracts with ten-year terms. Mr. Gaskill also addressed Dr. Vitolo's testimony that QF solar projects are not being treated comparably with utility projects that can depreciate their costs over their useful lives. Mr. Gaskill testified that rate regulated utilities vary significantly from QFs in terms of the obligations they have to customers, as well as how they are organized, regulated, and financed, and obtain cost recovery,

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[6] T. Vol. 5, p. 176.

and in what obligations they have to customers, so Dr. Vitolo's recommendation that the Commission require the utilities to offer solar QFs fixed contracts at lengths that match the recovery period of the respective utility's own assets should be rejected.

DISCUSSION AND CONCLUSIONS

Whether the Commission should require the electric utilities to offer long-term levelized rates to a QF as standard rate options has been an issue in numerous prior avoided cost proceedings.[7] The utilities in multiple dockets have contended that these rates are based on long-term projections of costs that are inherently unreliable, and that ten- and 15-year levelized rates are not specifically required by either state or federal law. Most recently in the Sub 140 proceeding, the utilities proposed to reduce eligibility for standard contracts to 100 kW and eliminate 15-year contracts, citing the rapid increase in QF development in the State.

The Commission, however, has generally rejected these efforts to adjust the eligibility threshold for the standard contract. The Commission in its Phase One Order reaffirmed its position that a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of FERC's J.D. Wind

[7] See, e.g., Docket No. E-100, Subs 79 (1996), 81 (1998), and 87 (2000), in which DEP, DEC, and DNCP all proposed eliminating the ten- and 15-year levelized rate options from the standard rates available to QFs; See also Docket No. E-100, Sub 96 (2002), in which DEC proposed eliminating ten- and 15-year capacity and energy rates, while DNCP proposed eliminating the two-year capacity rate and the ten-and 15-year energy and capacity rates, and Docket No. E-100, Sub 100 (2004), in which DEC proposed to limit the availability of ten- and 15-year levelized rate options to new projects.

Orders.[8] FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility.

In the Phase One Order, the Commission further stated that it "must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers." In making this determination, the Commission noted the importance of balancing the costs, benefits, and risks to all parties and customers, and recognized that regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy. The Commission noted the widespread QF development under the existing thresholds, but did not find sufficient evidence at that time to indicate that the existing framework failed to comply with the requirements of PURPA or otherwise disadvantaged QFs.

As noted by the Public Staff, however, the past two years have brought unprecedented growth and activity in QF development in the State. The number and capacity of QF projects that have been constructed or are under development far exceed those previously experienced in the State during any other period of QF development. Duke witness Bowman testified that the amount of installed utility-scale solar capacity in DEC'S and DEP's territories increased from approximately

[8] *See J.D. Wind 1, LLC*, 129 FERC ¶ 61,148 (2009), *reconsideration denied*, 130 FERC ¶ 61,127 (2010) (2010 Order; collectively *J.D. Wind* Orders).

125 MW in 2012 to over 1,600 MW in 2016. Further, she indicated that there are an additional 4,900 MW of proposed solar projects that are either under construction or pending in DEC's and DEP's interconnection queues. DNCP witness Gaskill similarly noted that distributed solar in DNCP's North Carolina service territory has increased from 58 MW under contract to over 435 MW currently operational at the distribution level, with an additional 537 MW under construction or pending in its distribution interconnection queue. Combined with the projects proposed in the PJM interconnection queue for North Carolina at the transmission level, these facilities represent almost 2,800 MW of solar projects that are operating or in the interconnection process.

The Commission agrees with the Public Staff that the significant growth of facilities from which the utilities are obligated to purchase energy and capacity may not only increase the risk of potential overpayments by ratepayers, but that the higher penetration of intermittent QF resources may also pose operational and technical challenges for the utilities to meet their obligation to provide safe, reliable, and economic service to ratepayers. As such, the Commission believes it is appropriate at this time to re-evaluate its avoided cost policies in the face of these rapid and continually evolving conditions.

In the Sub 140 proceeding, the utilities' justification for adjusting the standard offer thresholds was largely based on the fact that avoided costs rely on forecasts and that forecasts are seldom accurate. Similarly, in this proceeding the utilities emphasized that continued changes in fuel and energy prices have resulted in current prices being significantly lower than those approved in prior avoided cost proceedings, resulting in customers being obligated to pay avoided cost rates to QFs that exceed current energy prices.

The utilities testify that lowering the eligibility cap for the standard tariff will improve the calculation of avoided cost rates to be more reflective of the nature and rapidity of relevant changes, and will also reduce risk to customers. Increasing the use of negotiated contracts with QFs, as compared to continued reliance on the standard offer contracts, which have been one of the key drivers of QF development to date, will provide for more timely and accurate calculations of avoided cost rates.

As discussed in the Phase One Order, FERC's order implementing Section 210 of PURPA explicitly states that the goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF. FERC concluded that ratepayers also benefit because of the resulting reduced use of fossil fuels, the addition of smaller increments of capacity, and the resulting diversity of power supply. As discussed by Duke witness Snider and Public Staff witness Hinton, both QF contracts and utility-owned generation represent long-term fixed price obligations on behalf of utility customers that are also based largely on forecasts of future fuel prices. In cases where avoided costs are either overestimated or underestimated, ratepayers face increasing risk that they will pay too much for electricity, whether the utility builds the plant and places it in rate base or the utility pays QFs avoided cost rates. The Commission must establish avoided cost rates based upon the best information available at the time, and as long as rates accurately reflect the utilities' avoided costs over the long run, ratepayers should pay no less and no more for power generated by QFs than power generated by the utilities.

The Commission must always balance the federal public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers. The record shows that QF development in the State has flourished under the existing framework to such an extent that it exceeds the utility's short-term needs for additional energy and capacity and as a result puts ratepayers at risk of paying in excess of what is actually being avoided by the utilities. In addition, the utilities have presented information showing that ratepayers may soon be experiencing adverse operational impacts from these QF projects, and the benefits associated with small-scale QF development such as reducing line losses and smoothing capacity additions to match load growth, may be lost. While the Commission recognizes that changing the standard offer terms and thresholds may increase the regulatory uncertainty for QFs provided under the existing framework, it finds that it is appropriate at this time to shift the balance towards reducing the risk being born by customers.

In the Phase One Order, the Commission found that very few negotiated PPAs had been entered into, despite a large amount of QF development taking place. The Commission found that the process of negotiating PPAs for projects that fall outside the standard tariff remained a very challenging proposition. The evidence in this case indicates that some progress has been made on this front. As noted by Public Staff witness Hinton, DEC and DEP indicated that they have signed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and DNCP indicated that six of the 12 non-standard PPAs it signed have ten-year terms, indicating that not only are QFs having success negotiating PPAs with the utilities, but they are also accepting terms shorter than the current standard offer.

The Commission agrees with NCSEA witness Strunk and CCR witness McConnell that these shorter terms may result in higher interest rates or a higher level of equity investment by QFs, and in some cases, projects that are marginally viable may not be able to secure reasonable financing. However, as stated by Duke witness Bowman, "PURPA is not intended as a means to make any and all QFs viable." (T. Vol. 2, p. 380). As we have previously stated, PURPA specifically requires the Commission to balance the goal of encouraging QF development and the interests of the State's electric customers. As such, the Commission agrees with the Public Staff that the utilities' proposal to reduce the standard offer contract term to ten years for non-hydroelectric QFs is reasonable in light of current circumstances. Further, the Commission agrees that reducing the eligibility cap for standard rates, terms, and conditions from five MW to one MW is reasonable at this time.

The Commission believes that these adjustments will enable utilities to negotiate more accurate avoided cost rates using more up-to-date data and taking the specific characteristics of a QF into consideration, reducing the risk of overpayment by customers, while still allowing smaller QFs that may not be able to justify the cost and effort of negotiating rates to utilize the standard tariff. To ensure that the negotiation process operates efficiently, the Commission finds merit in Duke witness Freeman's proposal to more efficiently manage the negotiated contract process through the use of standardized contracting terms, as discussed in Finding of Fact No. 31 later in this Order.

These changes, viewed jointly with the other changes being adopted by the Commission, reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing additional protection to ratepayers from overpayment risk and certainty to QFs. The Commission will continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to seek financing on reasonable terms.

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

The Commission notes that, consistent with G.S. 62-156, it is appropriate for the utilities to continue to offer the option of five-, ten-, and 15-year terms for hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a), consistent with those offered in previous rate schedules and with the stipulation filed by DEC, DEP, and the NC Hydro Group in Sub 140 proceeding.

Further, the Commission concludes that it is appropriate for DNCP to continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM Reliability Pricing Model (RPM), subject to the same conditions as approved in the Sub 106 Order and most recently restated in the Phase One Order.

In conclusion, DEC, DEP, and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to hydroelectric facilities owned or operated by QFs contracting to sell five MW or less capacity, but that it is appropriate at this time for the utilities to reduce their long-term levelized capacity payments and energy payments to ten-year periods as standard options to non-hydroelectric QFs contracting to sell one MW or less capacity. The Commission will continue to monitor the amount of actual QF development and take action in future proceedings as warranted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is found in the Joint Initial Statement of DEC and DEP, the Initial Comments and Exhibits of DNCP, the testimony of Duke witnesses Bowman and Snider, the testimony of DNCP witnesses Gaskill and Petrie, the testimony of NCSEA witness Johnson, the testimony of SACE witness Vitolo, and the testimony of Public Staff witness Hinton.

DEC and DEP in their Joint Initial Statement indicated that they would continue to apply the peaker methodology to derive their respective avoided energy and capacity costs, but the term and structure of the proposed standard offer rates as well as other key inputs must be adjusted to more accurately reflect their true avoided costs. Among those changes was an adjustment to the capacity component of the peaker methodology to recognize capacity value only in years where the utilities' IRPs show an actual capacity need. DEC and DEP stated that their proposed rates would moderate the impact of their near-term lack of capacity need by levelizing the capacity component over the ten-year term of the proposed standard offer.

DNCP in its Initial Comments proposed to modify its Schedule 19-FP to reduce the capacity payment to $0/kWh for the entire term of the contract, on the basis that it does not need additional solar capacity in North Carolina over the ten-year planning horizon. Citing FERC's Order No. 69 and Ketchikan, DNCP stated that FERC has made it clear that an avoided cost rate does not need to include capacity costs where a QF does not permit the utility to "avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility."[9] DNCP noted that its capacity need has changed

[9] *City of Ketchikan,* 94 FERC ¶ 61,293, 62,062 (2001) ("*Ketchikan*") (citing *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility*

since the July 2014 hearing held in the Sub 140 proceeding. Since that time, reductions in load forecast, the addition of new generation to DNCP's fleet, and a large influx of QFs has moved the utility's next new capacity need several years into the future. DNCP indicated that its 2016 IRP does not indicate an avoidable capacity need until 2022 at the earliest, but under the most recent PJM load forecast, a capacity need does not arise until the 2026 timeframe. DNCP further noted that because its North Carolina service area has seen tremendous growth in solar QF development, adding additional solar generation will not avoid its long-term capacity costs or incrementally reduce load. DNCP notes that its next capacity need shown in its 2016 IRP is a combustion turbine (CT) in 2022, and noted that CTs are generally located near areas with increasing load growth and where additional generation is needed to reduce congestion and improve reliability, which would not likely be in DNCP's North Carolina service area.

Duke witness Snider testified that solar QF resources have demonstrated only limited capacity value to help meet DEC's and DEP's winter peaks, which he indicated occur in the early morning hours around 7:00 a.m. when solar's output is minimal. He noted that although solar output increases in the mid-morning hours on clear winter days, DEC's and DEP's peak demand has typically already occurred, and since solar QF resources cannot be dispatched to meet peak demand conditions or changes in customer demand, its capacity value is limited. As a result of this limited capacity value, solar output is not displacing or allowing

Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs., Regs. Preambles 1977-1981 ¶ 30,128 at 30,870).

the utility to avoid future resource needs that are now being driven by a winter reserve margin target, and are therefore creating little capacity value for consumers.

Witnesses Bowman and Snider both testified that DEC and DEP recommend the capacity credits in the standard tariffs be adjusted to account for their respective relative need for generating capacity, such that the avoided costs calculations would only include a capacity value in those years where there is a need for additional capacity. Duke witness Snider testified that FERC has found that avoided costs should not include the cost for capacity unless the QF purchase will permit the purchasing utility to avoid building or purchasing capacity. Mr. Snider explained that to incorporate the need for capacity consistent with PURPA, the annual fixed capacity costs that go into the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists. He stated that the IRP presents a 15-year resource plan that identifies when the next generation unit is needed for reliability purposes, and that prior to the year in which the next generation unit is needed, the utility does not have a capacity need to avoid. Therefore, according to Mr. Snider, the calculation of the avoided cost rate should not include a capacity value for years prior to the first avoidable capacity need indicated in the IRP. He noted that DEC's and DEP's 2016 IRPs indicate their first capacity need in the 2022-2023 timeframe. Mr. Snider pointed out that QFs under the utilities' proposed tariffs would receive a capacity payment in years prior to the utilities' first need, but the payment would reflect a lower annual payment to account for the initial years in which no avoidable capacity costs were included in the rate calculation.

Ms. Bowman testified that if a QF is not allowing the utility to avoid capacity that the utility would otherwise generate or purchase from another source, then there is no incremental capacity cost being avoided. She noted that both Order No. 69 and subsequent FERC decisions have reinforced this point, and specifically discussed the decision in Ketchikan, in which FERC stated that while a utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. She also cited G.S. 62-156(b)(2), which provides that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity which could be displaced." (T. Vol. 2, p. 356).

Ms. Bowman discussed the Phase One Order, where the Commission cited FERC's decision in Hydrodynamics[10] as supportive of its determination that the utilities should not include zeroes in the early years when calculating avoided capacity rates. Ms. Bowman testified that:

> The Hydrodynamics decision, however, did not pertain to a utility's proposal to recognize a capacity value only in years where the Companies' IRPs showed a need. Instead, Hydrodynamics concerned a limit on installed capacity purchases by Northwestern Energy from wind QFs. Upon review, FERC found that the 50 MW cap on QF-provided capacity prevented certain wind QFs from receiving any fixed, long-term compensation for capacity. Citing its decision in Ketchikan. FERC stated in Hydrodynamics that avoided

[10] *Hydrodynamics*, 146 FERC 61,193 (2014).

> cost rates need not include the cost for capacity when the utility's demand or need for capacity is zero. The FERC concluded, however, based upon the record before it, that the cap on installed capacity did not have "a clear relationship" to the utility's "actual demand" for capacity; therefore, the Ketchikan rationale did not apply.[11]

Ms. Bowman testified that unlike the utility in Hydrodynamics, DEC and DEP are not proposing to cap capacity purchases from certain solar QFs at an arbitrary level. They instead propose avoided cost rates "that moderate the impact of DEC's and DEP's near-term lack of capacity need by levelizing the capacity component over the ten-year term of the proposed standard offer." (T. Vol. 2, pp. 357-58). She testified that DEC and DEP will continue to purchase capacity, but they want the rates to reflect their actual capacity needs as reflected in their IRPs, which she testified would be consistent with the decisions in Ketchikan and Hydrodynamics.

DNCP witnesses Gaskill and Petrie testified that DNCP's membership in PJM requires the utility to procure capacity for at least three years into the future, which results in DNCP having met all of its capacity needs at all times over those initial three years. In addition, DNCP proposed to make no payment for avoided capacity in the short-run and over the next ten years. Mr. Petrie testified that in order for new QFs to avoid future capacity costs, (1) there must be a need for capacity and (2) the QF generation must be of the type and location to actually avoid that need. He stated that neither of these criteria is true for additional solar QFs located in DNCP's North Carolina service territory, based on the following reasons: (1) DNCP's 2016 IRP does not reflect a capacity need until 2022; (2) its

[11] T. Vol. 2, p. 357.

North Carolina service area has such high levels of solar projects already that additional solar generation in that area will have little to no peak load reducing effect on the system; (3) due to the intermittency of the solar generation that is coming online, DNCP is considering making changes to its resource mix to provide faster start-up and ramping capability, which could result in increased long-term capacity costs for customers; (4) due to the non-dispatchable nature of solar generation, it has limited usefulness during system emergencies, one of the factors specified by FERC that could be considered in determining avoided cost rates; (5) solar's limited availability results in it having limited value in PJM's RPM, which requires resources to have certain capacity performance characteristics; and (6) the addition of more solar resources will shift the timing of the summer peak to later in the day, thereby further diminishing the capacity value of additional solar resources.

SACE witness Vitolo testified that pursuant to the Phase One Order, the utilities used the peaker method, which requires that a utility determine the dollar-per-kilowatt cost of building a CT and spread those costs over the expected lifetime of the peaker unit, resulting in an annualized cost. The Commission detailed in the Phase One Order certain costs associated with the CT that were appropriate to include, but held that neither the expected dollar-per-kilowatt cost of the power plant the utility expects to build next nor the timing of that project was relevant to determining avoided generation capacity costs under the peaker method. He testified that it is inappropriate under the peaker method to refuse to provide an avoided generation capacity payment in the near-term years based on the linkage between the dollar-per-kilowatt cost of a CT and making a capacity payment in every year, noting that the peaker method's use of a CT rests on "the assumption that the utility's generating system is operating at equilibrium and that generation capacity payments will be made for all years in which the QF is in service." (T. Vol. 7, p. 46). He noted that DEC and DEP made a similar proposal in the Sub 140 proceeding, but the Commission declined to accept their proposal based on concerns raised by parties in that proceeding, noting that the cost of future needed capacity is not changed by the fact that a utility has sufficient capacity in the near term.

Dr. Vitolo testified that the peaker method is appropriate regardless of the technology or the details of the utility's future resource plans because the peaker method does not require that the QF have operating properties that align with the utility's planned capacity addition. With regard to DNCP's proposal to offer no avoided capacity payments, Dr. Vitolo testified as a summer peaking system, the PJM market has a surplus of capacity during the winter months, but a market demand for summer capacity. He testified that even if the solar capacity value in wintertime is assumed to be slight, solar QFs still offer DNCP the ability to defer or avoid costs, as well as to potentially sell surplus generation into the PJM market.

NCSEA witness Johnson summarized the peaker method and its traditional application by the Commission. He testified that when the peaker method was developed, it was assumed the marginal units would have high fuel costs, and as a result the system running costs would be much higher than the fuel costs of a new baseload plant. Quoting from the Commission's September 29, 2005 Order in Docket No. E-100, Sub 100 (Sub 100 Order), he noted that:

> The summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.[12]

Dr. Johnson testified in this proceeding, however, that based on DEC's and DEP's Prosym model runs, their baseload facilities were operating in such a way as to raise doubt about whether the marginal energy costs produced by Prosym are high enough to be fully consistent with the theory underlying the peaker method. Dr. Johnson testified that while lower QF rates may be superficially appealing (on the assumption that lower QF rates will translate into lower retail rates through a fuel adjustment and purchased power mechanism), artificially suppressed QF rates would not benefit ratepayers, since the lower rates would discourage QF investment, thereby reducing the amount of energy that the utility will actually obtain at the lower rates. He testified that over the long run, retail customers are harmed by artificially low QF rates, because low rates shield utilities from competition, reducing pressures for them to minimize their cost and encouraging the unnecessary expansion of the regulated rate base, for which customers bear the risk of cost overruns, high fuel costs, and potential delays. Dr. Johnson continued that:

> By setting QF rates equal to the cost of having the utility build and operate its own generating units, PURPA creates a level competitive

[12] T. Vol. 7, p. 176.

> playing field between utility-owned generation and QF power purchases. This encourages investment by QFs to the extent they believe they can operate more efficiently or at lower cost, or they are more willing to experiment with new technologies, or they are willing to accept a lower return on their investment than the one paid on comparable investments put into the utility's rate base. This creates healthy competition, which exerts downward pressures on retail rates, pressures the incumbent utilities to minimize their own costs, and benefits retail customers over the long term.[13]

Dr. Johnson testified that with regard to the use of zeroes, the Commission rejected similar proposals made by the utilities in the Sub 140 proceeding. He agreed with the decision reached by the Commission in the Sub 140 proceeding, and recommended that the Commission again reject the use of zeroes. He stated that the use of zeroes is inconsistent with the fundamental goals of PURPA and would lead to undue discrimination against small power producers, since they will not be fully compensated for the capacity value they provide to utilities. He testified that he believes that the goals of PURPA and the interests of society as a whole are best promoted when PURPA is implemented in a way that focuses on long-run incremental cost, rather than a short-run measure of cost that excludes capacity costs, and that avoided cost rates should reflect the full long-run cost of building and operating the utilities' generating facilities, including those years when new generating units are not being added.

Public Staff witness Hinton testified regarding the traditional application of the peaker method and its valuing of capacity over the entire planning period. He stated that according to the theory of the peaker method, the utility's generating system is operating at the optimal point, the capital cost of a peaker (based on a

[13] T. Vol. 7, p. 192.

CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. He noted that in reality, however, no utility system operates at the most optimal point and utility planners have to deal with unexpected changes in load, fuel costs, and other factors that challenge optimality. He expressed concerns that the rapid and substantial increase in QF development raises doubts as to whether the traditional application of the peaker method would continue to be appropriate and provide the market with a correct price for capacity. He noted that an end result of the traditional long-run application of the peaker method is that every kilowatt-hour (kWh) generated during on-peak hours provides capacity value and this value is quantified from the first day of QF operation, regardless of the utilities' short-run needs for additional capacity.

Mr. Hinton testified that contrary to the position taken by the Public Staff in prior proceedings regarding the use of zero capacity value in certain years, he believed that in light of current circumstances related to the amount of solar generation online and pending in the interconnection queue, it is appropriate for the utilities to adjust their avoided cost rates to provide a capacity payment to new QFs only when additional capacity is needed on the system. He further stated that by restricting the inclusion of a capacity credit until the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market.

Mr. Hinton indicated that the Public Staff supports Duke's proposal to limit capacity payments until the IRP dictates a capacity need in this proceeding, but that conditions in future proceedings may lend to reconsideration of this issue, as well as the continued applicability of the peaker method. Mr. Hinton noted that DEC indicates a resource need of approximately 3,903 MWs over the planning period (2017-2031), with the first resource need in the 2022/2023 timeframe, and DEP indicates a resource need of approximately 4,071 MWs over the same planning period, with the first resource need in 2021/2022.

With regard to DNCP's position that that the existing and projected level of solar generation exceeds the load in its North Carolina service territory such that there are no more capacity costs to be avoided with additional QF generation, Mr. Hinton testified that DNCP's proposal seems to run counter to general principles of utility system planning. Mr. Hinton testified that utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis. This system perspective is applied in various regulatory proceedings, including IRP proceedings, where Mr. Hinton noted that DNCP's 2016 IRP indicates a capacity need of approximately 4,457 MW, with the first resource need in 2022. In addition, Mr. Hinton testified that one of the central arguments in DNCP's application to join PJM was that DNCP's membership would make the utility part of a vast integrated transmission system with interfaces with PJM-East, PJM-West, and AEP with greater access to generation resources, load diversity, and improved reserve sharing across the region. Mr. Hinton disagreed with DNCP's argument that there is no capacity value associated with incremental

QF generation. He therefore recommended, like DEC and DEP, that the Commission require DNCP to provide a capacity credit based on the first indicated need in its IRP.

In his rebuttal testimony, Duke witness Snider disagreed with NCSEA witness Johnson's assertion that providing no capacity value until the utility has a need for capacity is discriminatory towards QFs. He stated that conversely, the inclusion of a capacity value for something that is not actually avoidable results in an overpayment by consumers, in violation of PURPA. He argued that Dr. Johnson's assumption that utilities overbuild, but are still able to recover the costs of the excess capacity, is incorrect. Instead, Mr. Snider testified that:

> [w]hen a larger unit is selected in a resource plan, it is because that resource is the most economic resource option for consumers. When building larger units, the Companies achieve economies of scale and operating efficiencies that provide a more economic and efficient solution for consumers as compared to smaller increments of generation.[14]

He further noted that while smaller increments of generation keep the utilities closer to their minimum reserve margin, they may still not be economically optimal for consumers, particularly when the utilities cannot control and dispatch the generating resource. The selection of a larger scale resource is made only after careful consideration of all the costs and benefits of smaller scale generation versus larger scale generation. Mr. Snider testified that under any circumstance, it harms consumers to pay for capacity that is not actually avoided.

[14] T. Vol. 2, p. 274.

Ms. Bowman in rebuttal testified that FERC has expressly stated that PURPA does not obligate a utility to pay for capacity that would displace its existing capacity arrangements, and that neither PURPA nor FERC's regulations require utilities to pay for a QF's capacity irrespective of the need for that capacity. She further discussed FERC's holding in Hydrodynamics, in which the FERC reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero," but noted that FERC in that case found the arbitrary cap set by the state on eligibility for capacity payments was inconsistent with its avoided cost regulations because the cap was not related to the utility's actual capacity needs. (T. Vol. 2, p. 414).

DNCP witness Petrie in rebuttal acknowledged that generation and transmission planning is done on a system-wide basis. He noted, however, that location does matter in regards to resource expansion planning, and that adding more intermittent generation at the distribution level in northeastern North Carolina where DNCP already has reached the point where solar generation exceeds its load, does not further reduce load, and therefore does not allow DNCP to avoid the need for new capacity.

Responding to the testimony of SACE witness Vitolo, Mr. Petrie testified that PJM does have a need for capacity to meet both the summer and winter peak, the PJM capacity market reflects such needs, and under PJM's Capacity Performance (CP) market rules, generators in PJM are responsible for providing reliable capacity in all months of the year, not just summer. He indicated that since solar resources provide little or no capacity benefit at the winter morning peak, they are subject to significant capacity performance penalties if they choose to bid into the RPM. Regarding the solar capacity value provided in PJM's RPM auction, he noted that solar units that offer into the RPM auction today are subject to the same financial penalties that apply to conventional fossil-fueled resources for non-performance on critical days, and that, on a risk adjusted basis, the capacity credit of a solar resource offered into the CP market is in the range of zero to 20% of nameplate capacity. He stated that this reduced capacity percentage, along with CP financial penalties, demonstrates that from a reliability perspective, solar resources can only be counted on for a small portion of their nameplate capacity. Therefore, Mr. Petrie stated that continuing to pay new solar QF resources rates for avoided capacity when they do not defer or avoid capacity needs for the utility results in an overpayment beyond actual avoided costs.

In response to NCSEA witness Johnson's comments regarding the use of zeroes for the years of the contract in which there is no demonstrated capacity need, Mr. Gaskill and Mr. Petrie testified that FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source. They testified that DNCP will not avoid or defer future capacity needs because of additional solar QF generation in its North Carolina service area, so it is therefore appropriate to set avoided capacity costs zero.

Mr. Petrie testified that while DNCP's position is that capacity rates should be set at zero in this proceeding for the duration of the standard offer contract, it would accept Duke's proposal to include zeroes in the calculation of the capacity rates for the years where its IRP does not indicate a capacity need, as agreed to by Public Staff witness Hinton. He testified that while the addition of QF power during this period of excess capacity will not avoid or defer the need for capacity, including zeroes for the years where there is no capacity need, it will come closer to valuing the capacity appropriately over the duration of the long term QF contract than paying for capacity over the entire term when there is no demonstrated need.

DISCUSSION AND CONCLUSIONS

In the Phase One Order, the Commission determined that "it should not authorize as a generic principle that the avoided cost rate should be reduced when the utility shows no need to acquire QF capacity when QF contracts are entered into," and held that it was inappropriate in that proceeding to require the inclusion of zeroes in early years when calculating avoided capacity rates under the peaker method.[15] Recognizing that FERC's prior decisions addressing this issue were not uniform and tended to turn on the unique facts of each case, the Commission noted that in Hydrodynamics (146 FERC ¶ 61,193), FERC explained that avoided cost rates need not include the cost for capacity in the event that the utility's demand or need for capacity is zero. However, FERC noted that the period over which the need for capacity needs to be considered is the planning horizon. Quoting from

[15] Phase One Order at p. 35.

Ketchikan, FERC found that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity." Ketchikan, at 62,062. Based on the facts of Hydrodynamics, FERC determined that if a utility needs capacity over its planning horizon, i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity that would be avoided.

The Commission also expressed its concern in the Phase One Order that including zeroes in the early years when calculating avoided capacity rates would lower the avoided cost rate for the entire 15-year period, and that the resulting avoided cost rates may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. The Commission noted at the time that the most recent IRPs for DEC, DEP, and DNCP showed a significant need for capacity over the next 15 years.

As noted by Public Staff witness Hinton, however, the peaker method is based on an assumption that the utility is operating at an optimal point, and that utility planners can reasonably anticipate capacity being added in discrete increments. The last few years have provided a dramatic shift in the landscape of QF development in North Carolina, with significant additions of QF generation primarily from utility-scale solar QFs beyond the control of utility planners and operators. While it is unclear how much solar will ultimately be built in North Carolina and over what timeframe, the changes underway challenge many of the assumptions regarding the application of the peaker method, as well as threaten to obligate customers to pay for capacity well in excess of what may actually be avoided.

The Commission notes that DEC, DEP, and DNCP all continue to show additional need for capacity in their IRPs, but also realizes that the mere presence of QF capacity, including solar nameplate capacity, does not always translate into an avoidance of capacity needs by the applicable utility. FERC's regulations implementing PURPA provide that states shall consider a number of factors in determining avoided costs, including the availability of capacity or energy from a QF during the system daily and seasonal peak loads (including dispatchability, reliability, and the individual and aggregate value of energy and capacity from QFs), as well as the relationship of the availability of energy and capacity from the QF to the ability of the utility to avoid costs.[16] The capacity value provided by additional solar PV does not necessarily help the utilities to offset or avoid their next capacity need, which are now being driven more by winter planning reserves. Solar may provide some limited seasonal capacity benefit, but may also create other operational challenges due to its non-dispatchability and intermittency that offset the capacity benefits. The Commission finds that it is appropriate to consider the operating characteristics of a QF resource to evaluate whether the QF can help to avoid the utility's planned capacity addition.

The Commission agrees with NCSEA witness Johnson that the appropriate analysis of capacity needs is done over the long run, and the use of zeroes in the

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[16] 18 C.F.R. 292.304(e).

early years will have the effect of lowering the avoided cost rates for the entire period. The Commission finds that outcome may provide avoided cost rates that more accurately reflect the cost being avoided by the utilities, in light of the tremendous amount of current and pending growth from QFs in North Carolina. As stated by Public Staff witness Hinton, by including a capacity credit only in those years in which the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market.

Further, the Commission agrees with Dr. Johnson that the utilities should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified to ensure that the change in policies being adopted in this proceeding do not adversely impact other small power producers, including wind, methane from landfills, hog or poultry waste, and non-animal biomass, for problems that are specifically related to solar energy.

The Commission makes this determination solely for the purposes of this proceeding and directs the utilities to re-evaluate the appropriateness of the use of zeroes in future biennial proceedings. As discussed further in this Order, the Commission believes that a solar-specific avoided cost rate may also be appropriate going forward in future proceedings.

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

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider, the testimony of DNCP witness Petrie, the testimony of NCSEA witness Johnson, the testimony of SACE witness Vitolo, and the testimony of Public Staff witnesses Hinton and Metz.

Duke witness Snider testified that DEC and DEP are requesting the PAF be lowered from 1.20 to 1.05 to better align with the reliability of a CT, which the he stated is the basis for establishing the avoided capacity cost under the peaker methodology. Witness Snider testified that when calculating avoided cost rates using the peaker methodology, the resource a QF replaces is a CT and the appropriate measure of reliability for a CT peaking unit is starting reliability. He indicated that DEC's and DEP's CT fleet performs at a greater than 95% starting reliability, therefore, the PAF should be set no higher than 1.05 as anything higher would exceed the costs actually being avoided. Mr. Snider stated that a reduction of the PAF to 1.05 would allow customers to pay rates that more closely approximate the economic value under the peaker methodology.

Public Staff witness Metz agreed with Duke witness Snider that the current 1.2 PAF may no longer be appropriate for calculating avoided cost rates, but did not agree that the appropriate PAF should match the starting reliability of a CT. Mr. Metz testified that a PAF value of 1.16, reflective of a broader plant availability factor average of 86.33%, would be more appropriate. He stated his calculation was based on plant performance data filed by DEC, DEP, and DNCP in monthly

Commission Baseload Power Plant Performance Reports, data obtained from SNL Financial, and responses to Public Staff data requests. His calculation includes intermediate generating units in addition to baseload units, as well as some operating characteristics about certain generating facilities, including the changing characteristics of utility generation portfolios that have natural gas CC facilities running more like baseload units and coal facilities running as intermediate units. Witness Metz testified that the use of the peaker methodology represents the "pure" capacity value of all generation, not just a CT, as a CT is used in the calculation because it is typically the smallest and least expensive increment of dependable, dispatchable capacity that a utility can install to meet load. He also stated that a QF may operate many more hours in a given year than a typical CT, therefore basing the PAF solely on the availability factor of a CT is not reflective of how the QF operates, or how a utility's own fleet of generating units operates. Witness Metz asserted that the Commission should consider his revised PAF calculation based on the historic weighted availability factor of the utilities' baseload and intermediate generating units as a refinement and update to the previous PAF approved by the Commission.

Public Staff witness Hinton testified that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constituted the utility's avoided cost. He stated that the Commission has previously concluded that using a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83% of the on-peak hours and the Commission has consistently reaffirmed a 1.2 PAF. Witness Hinton asserted that the Commission has specifically rejected in past proceedings the argument that the starting reliability of a CT should be used to establish the PAF, most recently in the Sub 140 proceeding where the Commission concluded that the availability of a CT is not determinative for the purposes of calculating the PAF because the fixed costs of a peaking unit are just a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. He then stated his agreement with Witness Metz's calculation of a 1.16 PAF.

NCSEA witness Johnson testified that under the peaker methodology, it is more appropriate to focus on availability data for all types of units, including coal and CC, not just CT units. Witness Johnson further asserted that the PAF should take into account the entire life cycle of the unit, not just the first few years after it is built when reliability is at its peak and maintenance requirements are low, because aging units require more maintenance and more outages may occur causing reliability to decline. Witness Johnson stated that Duke is not being held to a 95% standard for its fossil fuel plants because it is currently dispatching coal plants that were originally built for baseload as intermediate units.

SACE witness Vitolo testified that witness Snider's proposal of a 1.05 PAF contained several errors. First, the resource that the QF is replacing is not a CT because the peaker methodology assumes that the utility's fleet is in equilibrium and therefore "the quantitative result is not biased by the choice of one particular technology over another." He also stated that there is no expectation that the QF will avoid the utility procurement of a specific generator technology or type and that in any given hour, the QF could be displacing a peaking unit, a mid-range unit, or even a baseload unit – demonstrating that the QF's availability should be compared to the utility's entire fleet. Witness Vitolo asserted that a well-performing generator should not hide under-performing generators and the Commission should look at average performance. Witness Vitolo testified that the Commission should maintain the current PAF of 1.2 because it better aligns with the expected availability of generating units in a utility's fleet.

On rebuttal, Mr. Snider testified that the objective of the PAF should be to ensure that a QF operating with a reliability equivalent to that of an avoided CT receives the full capacity value of the CT, and that under the peaker methodology, it is reasonable to view the "on-peak" reliability of baseload generation resources on DEC's and DEP's systems as equivalent to a reasonable expectation of QF availability. He stated that the purpose of the PAF is to place the QF and an avoided unit on the same basis in terms of their impact on system reliability. Mr. Snider argued that the Public Staff's focus on availability is flawed because its use of the annual availability factor for DEC's and DEP's generating fleet is not relevant since it includes the time units that are scheduled for maintenance, which is typically done during periods when energy demand is low and not during on-peak hours. Witness Snider concluded that if the Commission determined that the PAF should be based on system availability, as the Public Staff recommended, then it should be based on the Equivalent Forced Outage Rate, which represents the reliability of a unit or generating fleet during periods between planned maintenance intervals. According to witness Snider, this would also allow for a PAF of 1.05.

DNCP witness Petrie testified on rebuttal that the PAF should be adjusted and that a PAF of 1.05 would be appropriate as the CT is the basis of the capacity costs under the peaker method.

DISCUSSION AND CONCLUSIONS

In its Sub 100 Order, the Commission specifically concluded that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. The Commission reiterated this point in the Phase One Order and found that despite the widespread development of QFs, the existing framework was not resulting in adverse impacts to utility ratepayers. These circumstances, however, have changed, as evidenced by the utilities' increased operation of CC units as baseload and intermediate generation and their use of coal plants as intermediate and peaking generators, as well as increased use of CTs. While this development provides a credible reason to lower the PAF from the currently approved 1.2, it does not justify the use of a CT as the exclusive unit with which to compare QFs when calculating the PAF. Therefore, the Commission agrees that the calculation put forth by the Public Staff to utilize a historic weighted availability factor of the utilities' baseload and intermediate generating units is appropriate. The appropriate and reasonable historic weighted availability factor is 86.33%, which results in a PAF of 1.16.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding is contained in the Initial Statements and Exhibits of DEC and DEP, as well as the testimony of Duke witness Snider, Public Staff witness Hinton, NCSEA witness Johnson, and SACE witness Vitolo.

In its Initial Statement, DEC and DEP indicated that the Commission adopted a seasonal weighting of capacity with 60% assigned to summer and 40% to winter in the Sub 140 proceeding. In this proceeding, Duke proposed that capacity payments be adjusted to reflect a seasonal weighting of 20% summer and 80% winter. Duke witness Snider explained that this change was based on DEC's and DEP's 2016 resource adequacy studies (Astrapé studies) that showed that 80% of loss of load risk occurs during winter and 20% during summer. He noted that while DEC and DEP are still summer peaking, they have begun winter planning as winter load has become the driver for new capacity needs. Mr. Snider testified that from 2012-2016, DEC's annual peak was in the winter two of the five years, and DEP's was in the winter four of the five years. DEP expects its annual peak to be in the winter during the entire planning horizon used in its 2016 IRP, and DEC becomes winter peaking in 2027.

Public Staff witness Hinton expressed concern that Duke's proposed seasonal allocation factors overly emphasized winter periods. He noted the significant winter peaks in 2014 and 2015, but said that the summer peak remained considerable and cautioned against an overemphasis on winter peaks at this time. Mr. Hinton recommended that the Commission make a smaller change in the seasonal allocation factor than that proposed by Duke, to 60% winter and 40% summer, and revisit the issue once there is more information and confidence regarding the utilities' emphasis on winter planning.

NCSEA witness Johnson testified that he had reviewed DEC's and DEP's hourly load data from 2006-2015 and determined that 86.5% of the most extreme system peaks occurred from June through September, while the remaining 13.5% occurred in the winter months of December through February. He concluded that rather than shift seasonal allocation toward winter, these data support a stronger allocation toward summer. He recommended that the Commission create three sets of months: June through September; December through February; and the remaining months for allocating capacity seasonally. In the alternative, Dr. Johnson proposed that the Commission retain the current 60% summer and 40% winter allocation.

SACE witness Vitolo expressed concern about using the Astrapé studies as a basis for the seasonal allocation, as the 36 weather years (1980-2015) in the studies were developed using five years of historical weather and load data that included the polar vortex years of 2014 and 2015. Dr. Vitolo stated that this could overstate winter peaks. He also noted that the studies did not account for any investments Duke may make to meet wintertime reliability challenges. He pointed out that the Astrapé studies are for use in 2019, and do not pertain to 2017 or 2018. He recommended that the Commission assign 80% of capacity to summer and 20% to winter for 2017 and 2018.

In his rebuttal testimony, Duke witness Snider noted the differences between being winter peaking and winter planning. He explained that the shift to winter planning is driven by the impact of solar generation. He did not refute NCSEA witness Johnson's calculations of peaks based on the hourly load data, but contended that the calculations failed to consider reserve capacity. In response to the testimony of Public Staff witness Hinton, Mr. Snider explained that the shift to winter planning is not due to the load forecast, but due to penetration of solar resources and winter load variability. Mr. Snider noted that the Astrapé studies modeled 36 weather years using the last five years' weather and load data to develop weather and load relationships. Mr. Snider stated that the impact of Duke's proposed change in seasonal allocation of capacity payments to QFs would be approximately one percent, and have no effect on baseload QFs.

DISCUSSION AND CONCLUSIONS

The parties' recommended allocations for seasonal capacity range from 80% winter and 20% summer as proposed by Duke, to 20% winter and 80% summer as calculated by SACE witness Vitolo. Duke's calculation is based on its Astrapé studies, which took into account the increasing impact of solar, but also used weather and load data from 2012-2016 to calculate relationships for other historic years. In addition to comments filed concerning this matter in the 2016 IRPs, witnesses for NCSEA and SACE pointed out that the use of five years of data that included the polar vortex years of 2014 and 2015 to develop relationships applied to other historic years could call the results of the Astrapé studies into question.

Regardless of whether Duke is winter peaking or winter planning, it is clear that Duke must plan to meet both its winter and summer peaks, both of which are substantial. The Commission finds that the recommendation by Public Staff witness Hinton to move to an allocation of 60% winter and 40% summer properly recognizes Duke's shift to winter planning and the possible shift to winter peaking, yet appropriately reflects the current uncertainty inherent with the impact of changing weather and the impact of solar generation at the time of peak demand.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 AND 12

The evidence supporting these findings of fact is found in the Joint Initial Statement of DEC and DEP; the testimony of Duke witnesses Bowman and Snider; the testimony of DNCP witnesses Gaskill and Petrie; the testimony of NCSEA witness Johnson; the testimony of CCR witness McConnell; the testimony of SACE witness Vitolo; and the testimony of Public Staff witness Hinton.

Duke witness Bowman testified that DEC and DEP propose to offer a single ten-year long-term avoided cost contract with fixed capacity rates, but require that the corresponding energy rates be updated every two years as part of the Commission's biennial avoided cost proceeding. She indicated that resetting the energy component would mitigate forecast risk associated with long-term commodity prices and better protect customers from overpaying for avoided energy in future years for which commodity forecasts are not as certain.

Ms. Bowman further testified that that Duke's proposal will provide QFs with a continuing revenue stream, but also has the potential upside benefit of increased rates if energy prices increase above forecasted levels during the contract term.

Duke witness Snider testified that fuel prices, particularly natural gas prices, have declined significantly in recent years, and result in the standard offer rates no longer being reflective of current and future commodity prices. He testified that recalculating energy rates on a more regular basis would allow for better alignment with future fuel commodity prices. Mr. Snider testified that a structure that adjusts the energy rates at reasonable, periodic intervals throughout the duration of a long-term contract would help to reduce customers' exposure to overpayments, while also ensuring that the value of the QF power aligns with the price consumers are paying for that power, adhering to the "but for" principle of PURPA.

Mr. Snider testified that in the Sub 140 proceeding, long-term fixed avoided cost rates were based on fuel commodity prices forecasted ten and 15 years into the future, and that maintaining the eligibility for those rates over two years resulted in "stale" rates being offered to QFs, with customers bearing significant risk of overpayment if projections of prices were too high. He testified that these fixed rates therefore created a systematic bias in favor of QFs over customers, since QFs could choose to sell at the higher of existing stale long-term rates or negotiated long-term rates, or simply wait for new long-term rates in a rising commodity price environment. He testified that PPAs the utilities enter into outside of PURPA generally do not have similar long-term commodity price risk associated with them, because the energy payments are usually linked to a real time fuel price index. Mr. Snider indicated that to mitigate the potential harm to customers, DEC and DEP proposed to modify their standard offer contracts to require energy rates to be updated every two years as part of the Commission's biennial avoided cost proceeding.

CCR witness McConnell testified that "fixed rates for a fixed period of time create financeable contracts," and that what creates value in the contract is having a set avoided cost rate for a set period of time. (T. Vol. 6, p. 116). Without these fixed rates, lenders are unwilling to bet on what the avoided cost rates will be going forward. Mr. McConnell testified that in a regulated market, a ten-year contract with a two-year reset for energy prices would be viewed as more or less equivalent to a two-year contract, and would likely not be financeable in the current environment.

SACE witness Vitolo testified that DEC's and DEP's proposed change in the energy payment schedule is not appropriate since the lack of set avoided energy payments over the life of the contract would jeopardize project financing and likely discourage QF development contrary to the policy goals of PURPA. He also noted that this change would reduce the rate stability provided by decoupling some generation from variable fuel prices. He testified that FERC held in <u>J.D. Wind</u> that QFs are entitled to receive long-term avoided contracts or other legally enforceable obligations "with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." (T. Vol. 7, pp. 36-37).

Dr. Vitolo testified that changing the payment every two years would differ significantly from how the utilities treat their own assets. He stated that a utility decision to build or purchase a generating asset nearly always includes a long-term obligation to pay for that capital asset, and that integrated resource planning and decisions to invest capital in new generators are also substantially influenced by long-term forecasts of costs, particularly fuel. He noted that in the Phase One Order, the Commission observed that

> While witness Snider's emphases that QF contracts represent long-term fixed price obligations on behalf of DEC'S and DEP's customers based largely on forecasts of future fuel prices, the Commission recognizes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects the utilities own self-build options are based upon similar "uncertain" forecasts.[17]

Dr. Vitolo also discussed the Commission's July 27, 2011 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 127, in which the Commission rejected DNCP's proposal to continue to offer variable avoided energy rates for QFs larger than 100 kW that would be updated every two years. The Commission determined that an avoided energy rate that "is reset every two years clearly does not qualify as either a fixed rate or as a fixed formula rate," and required the utility to begin offering fixed long-

[17] T. Vol. 7, p. 39, citing Phase One Order at p. 20.

term, levelized avoided energy rates for QFs entitled to standard contracts in the following biennial proceeding. (T. Vol. 7, pp. 39-40).

NCSEA witness Strunk testified that providing fixed prices for a term that is sufficient to provide a reasonable amortization of sunk investment costs for a long-lived asset has been key to the financing of new independent power production facilities. He testified that reducing the PPA term and including two-year energy price resets would raise the price that a QF requires to be viable for two reasons: (1) the QF's cost of capital will increase as its investors bear more risk; and (2) investors will seek shorter amortization periods for capital investments, which in turn translate to higher short-term cash flow requirements. He stated that reducing the term of the PPA therefore increases the near-term costs for the QF, decreases the possibility that those costs could be recovered under avoided cost pricing, and reduces the likelihood that the facility will actually be developed. This reduction of the time period over which fixed rates apply will lead lenders to view the effective PPA coverage period as only two years, even though Duke is proposing a ten-year PPA term. He indicated that lenders will significantly discount the revenues available beyond that two-year period, and as a result, it is unlikely that project debt could be obtained in reasonable quantities for terms longer than two years.

NCSEA witness Johnson stated that under the current avoided cost tariff structure in North Carolina, a QF benefits from a fixed revenue stream that aligns well with its fixed costs, but under DEC's and DEP's proposal to provide for a two year reset, avoided energy rates will suddenly become highly unpredictable. He testified that "[n]ot only will the future revenue stream depend on the future course of volatile fuel prices, but it will fluctuate with those prices in ways that are fundamentally unknowable and unpredictable from the perspective of the QF and their financiers, because it will depend on the outcome of litigated proceedings every two years." (T. Vol. 7, p. 268). Dr. Johnson testified that most non-PURPA sellers of power are burning fuel, so their use of a pricing structure that recognizes fuel price changes is appropriate. He noted, however, that this approach shifts the fuel price risk to the customer. Dr. Johnson testified that he did not think it was reasonable to apply a similar pricing arrangement to generators that do not consume fuel.

Public Staff witness Hinton testified that DNCP's proposal to provide fixed ten-year energy prices as part of its standard offer rates is reasonable and consistent with PURPA's goals of encouraging QFs. He noted that FERC in Windham[18] recently elaborated on this requirement more fully, as follows:

> [T]he Commission has long held that its regulations pertaining to legally enforceable obligations "are intended to reconcile the requirement that the rates for purchases equal to the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments, by necessity, on estimates of future avoided costs" and has explicitly agreed with previous commenters that "stressed the need for certainty with regard to return on investment in new technologies." Given this "need for certainty with regard to return on investment," coupled with Congress' directive that the Commission "encourage" QFs, a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.[19]

[18] *Windham Solar LLC & Mto Fin. Ltd.*, 157 FERC 61,134 (Nov. 22, 2016).
[19] T. Vol. 8, p. 75, citing *Windham* at p. 8.

Mr. Hinton testified that he does not think offering a standard offer contract with a two-year reset on the avoided energy rates would provide sufficient "certainty with regard to return on investment" to provide a QF with a reasonable opportunity "to attract capital from potential investors." He noted that larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, but that resetting energy rates every two years for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which could make obtaining financing difficult or impossible.

Upon cross examination, Mr. Hinton acknowledged that Georgia Power offers fixed two-year energy rates and only pays for avoided capacity when the IRP shows a need, similar to DEC's and DEP's proposal. However, Mr. Hinton noted that there is little QF development in the states that offer a two-year energy rates, and that the development in those states is largely in response to legislative mandates for solar power. Mr. Hinton agreed that QF contracts contain risks that are ultimately borne by the customer. However, he stated that these risks need to be viewed in the context of a utility's long-term commitment to build plants, whereby such decisions as the building of Cliffside Unit 6 and the Richmond County CC units were based upon forecasts that are also uncertain, resulting in ratepayers bearing the same type of forecast risk from utility plants as they do from QFs.

Mr. Hinton described other options to reduce forecast risk that might be considered, such as linking available energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment that energy rates could vary from some indicative pricing. He stated that these options may provide QFs with additional certainty, while reducing ratepayers' risk of overpayment. Lastly, Mr. Hinton noted that the Public Staff was already proposing a number of other adjustments to the rate and terms under the standard offer in this docket that would more appropriately reduce the risk of overpayment by customers.

On rebuttal, Duke witness Snider testified that ten-year terms have proven to be financeable, at least for larger QFs, but that intervenors are implying that too little of the payment is fixed under the two-year energy reset approach to attract financing. He stated his understanding that nothing in PURPA requires states to offer prices at levels high enough to attract financing, and that Duke's position was fully consistent with PURPA and represents an appropriate adjustment to reduce overpayment risk.

Responding to Dr. Johnson's claims regarding the shifting of risk using a real-time fuel price index, Mr. Snider testified that a real-time fuel price index helps to lower risk, rather than increase risk. He indicated that the non-PURPA contracts to which he referred in his direct testimony are third-party owned dispatchable natural gas units, and that their dispatchable nature allows for the economic optimization of dispatch based on prevailing gas prices, as opposed to purchases from non-dispatchable QFs the utilities are obligated to buy at a fixed price.

In response to Public Staff witness Hinton's proposal to link avoided energy rates to a publicly available fuel index, he stated that such an approach may be a reasonable alternative and that Duke would evaluate the option further in the next biennial proceeding.

Mr. Snider and Ms. Bowman indicated that as an alternative compromise proposal, DEC and DEP proposed to offer standard offer QFs the option to "fix" the two year avoided energy rate for the full ten-year term, in recognition of the testimony offered by intervenors that small QF investors will view energy revenues in years beyond the proposed biennial update as risky and that a longer-term fixed rate (seemingly for both energy and capacity) is needed by smaller QFs in order to attract capital.

DISCUSSION AND CONCLUSIONS

This Commission in past proceedings, including the Sub 140 proceeding, has acknowledged a QF's legal right to long-term fixed rates under Section 210 of PURPA and under the J.D. Wind Orders. In addition, FERC's recent ruling in the Windham case is instructive in pointing out that the contractual commitments entered into by parties require a sufficient level of certainty with regard to return on investment in order for the parties to be able to seek financing for the projects. The Commission agrees with Mr. Snider that PURPA does not require states to offer avoided cost rates at levels high enough to attract financing – the avoided costs must be the utilities' full avoided costs. However, with regard to the form in which the rates are offered, they must be offered in such a way that an investor can evaluate the rates with some degree of certainty in order to make a determination of whether or not to invest in the project. This requirement that rates be presented in a predictable and certain manner is critical. DNCP's proposal to provide fixed ten-year energy prices as part of its standard offer rates is reasonable and consistent with PURPA's goals of encouraging QFs. The Commission agrees with NCSEA, SACE, CCR, and the Public Staff, however, that Duke's initial proposal to require energy rates to be reset every two years over the life of the contract term does not provide sufficient "certainty with regard to return on investment" to provide a QF with a reasonable opportunity "to attract capital from potential investors." As noted by the Public Staff, while some larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, the proposed two-year energy rate reset for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing difficult or impossible. The Commission also acknowledges that in addition to providing the basis for electric power purchases from QFs by a utility, the avoided costs determined by the Commission are utilized in other applications, including the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs; the determination of the incremental costs of compliance with the Renewable Energy Portfolio Standard

(REPS) for cost recovery purposes; and in some ratemaking, such as determination of stand-by rates. In these contexts, it is appropriate for the rates to be reflective of the utilities' actual forecasted rates over a longer term, not based on a short-term forecast that is fixed for the duration of a longer term.

Further, regarding Duke's proposed "fixing" of the two-year rate for the ten-year contract term, the Commission finds that such an approach to establishing a ten-year avoided energy rate may result in an understatement of the utility's avoided energy rates over that term, and would result in rates that do not reflect DEC's or DEP's avoided energy costs. However, developing avoided energy rates under a ten-year production simulation model, as done by DEC and DEP in calculating the rates available for run-of-river hydroelectric facilities, along with an appropriately constructed long-term natural gas price forecast, will provide a more accurate estimate of the value of the energy provided by the QF to the utility. The Commission acknowledges that this approach does still result in some forecast risk being borne by customers. However, in conjunction with the other modifications being made in this proceeding to the rate and terms under the standard offer, as well as establishment of a LEO, the Commission believes that the overall risk of overpayment by customers has been greatly reduced. Therefore, the Commission concludes that DEC's and DEP's proposed two-year reset of avoided energy rates is not warranted at this time.

With regard to the Public Staff's proposals to consider linking energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment by which energy rates could vary, the Commission agrees with Duke that these approaches may be reasonable in providing QFs with additional certainty, but at the same time reducing ratepayers' risk of overpayment, provided they are structured appropriately. To the extent the utilities wish to consider these proposals in future proceedings, they may do so, provided that they include sufficient supporting information and ensure that the factors on which the energy rates would adjust are based on publicly available information.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 AND 14

The evidence supporting these findings is contained in the December 17, 2015 Order in Docket No. E-100, Sub 140 (Phase Two Order), the direct and rebuttal testimony of Duke witness Snider, the testimony of Public Staff witness Hinton, and the testimony of NCSEA witness Johnson.

Duke witness Snider testified that fuel prices, and particularly natural gas prices have fallen significantly in recent years. He testified that ten-year (2017 to 2026) levelized natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period, as compared to those used in calculating DEC's and DEP's avoided energy costs in the 2014 proceeding. Mr. Snider noted that the lower Schedule PP rates proposed by DEC and DEP reflect a reduction in both the avoided energy and capacity components, and that the lower avoided energy rate results primarily from decreases in the projected costs of coal and natural gas.

Public Staff witness Hinton testified that he reviewed the coal and natural gas price forecasts used by the utilities and found most of the inputs to be reasonable, except for Duke's use of ten-year forward prices to develop its price forecast for natural gas. Mr. Hinton testified that these concerns were similar to those expressed by the Public Staff in the 2014 proceeding and in the 2016 IRP regarding DEC's and DEP's over-reliance on long-term forward prices for their fuel forecasts. Witness Hinton testified that in their 2014 IRPs, DEC and DEP incorporated five years or less of forward price data before transitioning their fuel forecast to a long-term fundamental natural gas price forecast. In their 2015 IRP updates, however, they made changes to this approach by extending the period on which they relied on forward price data to ten years. Mr. Hinton testified that the Public Staff and other parties advocated in the 2014 Proceeding that DEC and DEP return to their previous use of forward prices for no more than five years of the forecast before transitioning to a fundamental forecast developed by energy economists and gas analysts who estimate the future demand and supply of natural gas. Mr. Hinton illustrated the difference between DEC's and DEP's previous use of five years of forward prices by graphically contrasting DEC's natural gas price forecasts incorporated in the 2012 and 2014 IRPs with DEC's gas price forecast using ten years of forward prices that were initially proposed but ultimately rejected by the Commission. In addition, Mr. Hinton indicated that comparing DNCP's forecast from 2017 to 2031 with that of DEC and DEP, as well as noting the similarity in their predicted fuel prices in 2031, illustrates the impacts that result from the use of forward prices over the planning period.

In its Phase Two Order, the Commission ordered DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts constructed in a consistent manner with those utilized in their 2014 IRPs. Further, the Commission found that to the extent the utilities wished to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, that those changes should first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations. Mr. Hinton stated, however, that DEC's and DEP's proposed avoided cost rates in this proceeding again used ten years of forward prices and then shift to their traditional fundamental forecast for years 11 through 15.

Mr. Hinton testified that the Public Staff supports the use of forward prices as a component in the development of a long-term price forecast. He asserted that the use for up to five years is reasonable and appropriate because the market for these contracts is relatively liquid. With regard to ten-year futures, however, Mr. Hinton indicated that the market is relatively illiquid, meaning the number of natural gas price investors willing to make buy and sell decisions on future prices beyond five years out in the future is much smaller and less transparent. Mr. Hinton further testified that fundamental price forecasts and forward price-based forecasts are different and have different applications. In addition, he testified that traders in futures are more likely to respond to temporary conditions, as compared to fundamental price forecasts that are based on future demand and supply conditions, providing a more measured response to expected changes in the natural gas market.

Mr. Hinton testified that DEC and DEP did not use the same methodology for forecasting natural gas prices in their avoided energy calculations as was used in their 2014 IRPs, or the same methodology approved by the Commission in the 2014 proceeding. He noted that in the Phase One Order, the Commission emphasized the relationship between the generation expansion plan developed in the IRP and the determination of avoided energy costs that reflect current and future generation units combined with future renewable generation, demand-side management, and energy efficiency resources. In Phase Two, the Public Staff recommended the use of up to five years of forward prices in combination with a long-term price forecast, and the Commission ordered DEC and DEP to incorporate the natural gas price forecasts that are constructed in a consistent manner with the forecasts utilized in their 2014 IRPs. The Public Staff restated its view that an overreliance on forward price data can call into question the reasonableness of the long-term forecasts.

Mr. Hinton testified that he found DNCP's reliance on forecasts from ICF International, Inc. (ICF), the same source utilized for its 2016 IRP, along with DNCP's use of three-year forward prices before transitioning to a fundamental price forecast, to be reasonable. He disagreed, however, with Duke's use of ten-year forward prices, and instead, recommended that the Commission direct DEC and DEP to recalculate their avoided energy rates using no more than five years of forward natural gas prices before transitioning to their long-term fundamental price forecast. He stated that this approach would be consistent with the Commission's directive in the 2014 proceeding that DEC and DEP utilize natural gas price forecasts that are constructed in the same manner as the forecasts utilized in their 2014 IRPs, and is also consistent with the Public Staff's comments in the 2016 IRP proceeding.

NCSEA witness Johnson testified that he had similar concerns regarding the changes in future fuel prices used by Duke. He compared Duke's fundamental forecast with the fuel price forecasts used in its 2016 IRP, as well as in this proceeding, and noted that Duke used much lower prices to develop its proposed QF rates in this proceeding, with the lower fuel prices concentrated in the ten-year period which Duke used to calculate its avoided costs.

Dr. Johnson testified that Duke Energy Corporation goes to considerable effort and expense to develop its own, comprehensive fundamental forecast of the entire US energy sector, which is periodically updated, and it uses this long-term outlook to inform long-term investment decisions by all of its electric utilities. He contrasted that with forward market data:

> Forward market data is useful for short term forecasts, because it can easily and frequently be updated, as commodities traders respond to changes in the weather and minute-by-minute and day-to-day changes in supply and demand conditions in the commodities markets. In essence, forward market data is particularly useful for dealing with, and hedging against, fluctuations in commodity prices over the near-term future. But, it is not as useful, nor as appropriate, to use it for long-term planning purposes.[20]

Dr. Johnson further testified that Duke's reliance on its fundamental forecast was explained in great detail in a 2015 proceeding before the Florida Public

[20] T. Vol. 7, p. 249.

Service Commission.[21] In that proceeding, Mr. Kevin Delehenty of Duke Energy explained the fundamental forecast is provided to the fuels procurement group, which uses futures market quotes from the New York Mercantile Exchange (NYMEX) to estimate fuel prices for the first three years, followed by a two-year transition period of blended prices to the long-term fundamentals. The fundamental forecast is relied upon exclusively for the balance of the planning process. Mr. Delehenty also explained that the short-term fuels forecast is based on observed market prices, and is used mainly by Duke for operational purposes, while long-term investment decisions are based on the fundamental forecast.

Dr. Johnson stated that he was not aware of any similar claims that have been made by Duke Energy Corporation, or any of its operating utilities, to suggest that forward market prices are superior to their internally developed fundamental forecast for long-term investment decisions. To the contrary, he noted that Mr. Delehenty in the above-mentioned docket warned that futures market "prices are illiquid after the first few years and often do not reflect the impacts of proposed environmental rulemaking, retirements of existing generation, or changes in technology."[22]

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[21] *Id.* at 250, quoting from Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 12.
[22] *Id.* at 252.

Dr. Johnson also described a recent analysis conducted by South Carolina Electric & Gas (SCE&G), in which the utility was evaluating the economic viability of its V.C. Summer nuclear construction project.[23] SCE&G started with

> two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor … to forecast prices beyond three years in the future.[24]

Dr. Johnson testified that he is particularly troubled with DNCP's use of significantly lower fuel prices in this proceeding than it used in the 2016 IRP proceeding, and even more troubled that Duke "essentially ignored" its fundamental forecast when developing its proposed QF rates.

Dr. Johnson testified that he found Duke's fundamental forecast, as well as the forecast DNCP used in its 2016 IRP filing to be reasonable, and that both are reasonably consistent with the most recent long term fundamental forecast of natural gas prices that was published in March 2017 by EIA. Dr. Johnson testified that it would be reasonable for the Commission to rely on this neutral, publicly available fundamental forecast as a benchmark for judging the reasonableness of the fuel prices the utilities used in calculating their proposed QF energy rates.

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[23] T. Vol. 7, p. 230, quoting from South Carolina Electric & Gas, Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, May 26, 2015, available at: https://dms.psc.sc.gov/Attachments/Matter/4c84883e-157b-4ad4-856a-c49a3c0b1b25.
[24] *Id.* at 231.

In addition, Dr. Johnson recommended that the Commission again reject the use of forward market data for anything more than the near-term future. To the extent some consideration is given to forward market data, he recommended using DNCP's blending approach, or potentially follow the approach that was described by Duke Energy Corporation's witness in Florida (the use of forward market data for the first three years, followed by a brief two-year transition period of blended prices to the long-term fundamental price forecast for all subsequent years).

In his rebuttal testimony, Mr. Snider testified that the fundamental forecasts take significant time to develop and are often only released by research firms once or twice per year. Additionally, the preparation of avoided cost filings also takes months to prepare and then can be subject to an extended regulatory review. As such, Mr. Snider indicated that the fundamental forecasts used by the utilities are clearly lagging the market. He testified that following the Phase Two Order, DEC and DEP developed both their 2015 IRP updates, as well as their 2016 IRP utilizing ten-years of forward market price data and then transitioned to fundamental forecast-derived data in year 11.

Mr. Snider further testified that on April 5th, 2017, DEP purchased forward gas contracts for 2,500 MMBtu/day for the period starting in May of 2017 and ending in December of 2026 that were at a price just below the market prices used in the utility's 2016 avoided cost filing. He testified that this transaction demonstrates market liquidity and provides a tangible price point for the natural gas market over the equivalent period of the ten-year hydro rate.

In response to the testimony of Mr. Hinton, Mr. Snider testified that based on his experience, long-dated forward contracts are liquid, transparent, and transactable, and may be purchased over-the-counter directly from large financial institutions and other firms. Mr. Snider testified that simply viewing contracts that trade on the NYMEX could lead to the false conclusion that long-dated gas markets are illiquid, and that typically only actual market participants that purchase or sell gas forward positions engage with these financial institutions. He further testified that DEP's recent ten-year purchase of a natural gas forward position demonstrates that it is an incorrect perception that liquidity does not exist in the long-dated forward markets.

Mr. Snider testified that there are additional issues associated with using fundamental forecasts as the basis for calculating avoided energy rates, based on the variability that may exist between the various fundamental price forecasts that are available and how the preferred fundamental price forecast would be evaluated and selected. He also testified that DEC and DEP used ten-year forward prices in their last two IRPs, which he stated was consistent with the Commission's instructions in the Phase Two Order.

During cross-examination by the Public Staff, Mr. Snider testified that he agreed that NYMEX and the Intercontinental Exchange, or ICE, were two of the largest energy exchanges where natural gas futures are traded, at least for the short-term market. While reviewing an end-of-day report from ICE, Mr. Snider identified the significant reduction in the volume of futures contracts traded over a longer period of time, and that while there was some limited trading activity in the first two to three years, there was no activity at ten years. Mr. Snider noted, however, that natural gas does not trade on ICE or NYMEX alone, and that most long-dated trades happen with financial brokers such as J.P. Morgan and others. Mr. Snider indicated that when Duke bought its ten-year forward, "it took one minute to make that transaction. It is not a big, complex deal. It's a very simple thing to pick up the phone and buy ten years of natural gas." (T. Vol. 4, p. 100). Mr. Snider testified that the ten-year purchase was made by the utility approximately two weeks prior and, that to his knowledge, the utility had not previously ever made a similar ten-year forward purchase or ten-year swap.

Mr. Snider further testified that with regards to the Public Staff's concerns over market liquidity, you could "call one of a [. . .] dozen financial institutions and get a quote for these prices," and that this ability to transact demonstrated there is a liquid market. (T. Vol. 4, p. 117). In response to Commission questions, Mr. Snider testified that the purchase was not quantity specific - the forward price would have been the same had it been for the gas-equivalent of 50 MW or 500 MW of solar. He also testified that Duke did not have to pay anything for the ten-year purchase.

Regarding the ten-year purchase, Mr. Snider testified that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**.

Mr. Hinton on cross-examination testified that he had not participated in forward markets, it was his understanding that the confidence associated with a price derived from a bilateral transaction may not be the same as that associated with the volume associated with an exchange trade. He took exception to the use of ten-year forward contracts for natural gas and testified that when DEP decides to use swaps to hedge its natural gas, it similarly locks in on a future price of gas. He testified that while DEP has historically engaged in long-term swaps at future contracted prices, this has resulted in customers bearing some of the same long-term risk, as noted in his affidavits filed in Docket No. E-2, Subs 1001, 1018, and 1031. Furthermore, Mr. Hinton testified that utilities such as TVA, Georgia Power, SCE&G, and others in the southeast do not rely on forward market prices for planning, avoided costs, or IRPs.

DISCUSSION AND CONCLUSIONS

As discussed in the Phase Two Order, the Commission recognizes the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates. In addition, the Commission notes that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and changes in the liquidity and trading prices in the natural gas markets over the long-term are being incorporated into long-term forecasts. In the context of both the avoided cost and IRP proceedings, recognition of these changing markets is appropriate.

In the Phase One Order, the Commission emphasized the relationship between the IRP and avoided costs and the need for their inputs and assumptions to be consistent. In this proceeding, the Commission again recognizes the important relationship that exists between the biennial avoided cost proceeding and the IRP, as well as the importance of maintaining internal consistency between these proceedings. With regard to DEC and DEP's assertion that their increased reliance on forward natural gas prices in the 2015 IRP Update and their 2016 IRPs reflects this consistency, the Commission notes that the 2015 IRP update reports were accepted by the Commission as complete and fulfilling the requirements set out in Commission Rule R8-60, but did not reflect the Commission's approval of any adjustments made to the natural gas price forecasting methodology used by the utilities. Similarly, the Commission notes that the 2016 IRPs are still pending before the Commission, and that intervenors, including the Public Staff, took exception to DEC's and DEP's increased reliance on forward natural gas prices in their comments in that proceeding, with the Public Staff recommending that the Commission require DEC and DEP in future expansion models to reflect the use of no more than five years of forward natural gas prices before transitioning to its fundamental forecast. While administrative lag is inevitable in some instances such as biennial IRP and avoided cost proceedings, the process is necessary to provide an opportunity for parties to comprehensively evaluate, in a meaningful fashion, significant changes to the plan and inputs used in the models.

The Commission also agrees that not only should the IRPs and avoided cost fuel forecasts be consistent, but the fuel forecasts should not deviate significantly from a utility's fuel procurement practices. To the extent a utility limits its exposure to risk in its hedging and fuel procurement practices, forward prices that exceed the established risk limits and do not necessarily reflect the same level of information and analysis of a fundamental market forecast should not form the basis for establishing inputs for avoided costs and integrated resource planning. Lastly, the Commission believes that if the utility believes that its fundamental forecast is "lagging the market," then it is appropriate to consider updating this information or revising its calculation to ensure that the integrity of the fundamental forecast remains valid.

The Commission recognizes that in some cases forward market prices may provide a better snapshot of prices over the near- and short-term future, and agrees that DEP's recent purchase of a ten-year natural gas forward is instructive in demonstrating that such long-term gas forwards are actually transactable. However, the Commission acknowledges that long-term swaps and other forward contracts expose ratepayers to risk of overpayment in the event that gas prices actually turn out less than the agreed upon price in the forward contract. Furthermore, the Commission agrees with the Public Staff and NCSEA that forward market prices do not reflect the same level of analysis and consideration performed by firms whose expertise is in long-term forecasting. In regard to the contracted price that DEP entered into on April 5, 2017, for gas delivered in 2027, the Commission notes that these prices may, in fact, be reasonable; however, DEP's historical experience with long-term forward contracts or swaps from natural gas hedging indicates that long-term forward prices bring their own set of risks to ratepayers.[25]

In view of all of the evidence in the record, the Commission finds that DEC's and DEP's use of long-term forwards is as inappropriate for an IRP as it is in the calculation of avoided energy costs. As such, the Commission agrees with the Public Staff that DEC and DEP should recalculate their avoided energy rates using natural gas and coal price forecasts that more appropriately reflect the balanced use of forward market prices for no more than five years before transitioning to their fundamental forecasts for the remainder of the planning period. The

[25] Page 2 of Hinton Affidavit in Docket No. E-2, Sub 1001, Page 4 of Hinton Affidavit in Docket No. E-2, Sub 1018, Page 3 of Hinton Affidavit in Docket No. E-2, Sub 1031.

Commission further finds that DNCP's use of three-year natural gas forward prices before transitioning to a fundamental price forecast is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding is contained in the testimony of DNCP witnesses Gaskill and Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

DNCP witness Gaskill testified that DNCP proposed to adjust its avoided energy rates to reflect the locational energy value its North Carolina service area as opposed to the entire DOM Zone. DNCP witness Petrie testified that the locational marginal prices (LMPs) in North Carolina were over 4% lower than those for the DOM Zone, and were likely to be even lower as compared to the DOM Zone in the future due to the future solar development in its North Carolina service territory.

Public Staff witness Hinton stated that this proposal was reasonable based on DNCP's showing that the LMPs in North Carolina had consistently been lower than those in the DOM Zone. NCSEA witness Johnson indicated that he did not oppose the proposal on a conceptual level as it sent appropriate price signals. However, he argued that there were a number of issues that should be investigated before adoption by the Commission, including the amount of and the reasons for the difference between the LMPs.

In rebuttal, DNCP witness Gaskill testified that DNCP had already provided in testimony and discovery information that should address most of the concerns raised by Dr. Johnson. Mr. Gaskill noted that DNCP would also be able to develop more granular prices for negotiated contract avoided energy rates based on the specific location of the QF.

DISCUSSION AND CONCLUSIONS

Both the Public Staff and NCSEA agree with the concept proposed by DNCP to adjust avoided energy rates based on LMPs. However, Dr. Johnson advocates that the Commission engage in further investigation before adopting the proposal. The Commission finds that DNCP's proposal to adjust its avoided energy rates to reflect the lower LMPs in North Carolina is reasonable for use in this proceeding, but that this adjustment should be re-evaluated and demonstrated in future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-19

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Holeman, NCSEA witness Johnson, and Public Staff witness Metz.

Duke witness Holeman discussed DEC's and DEP's roles as independent NERC Balancing Authorities (BAs) and the NERC BAL Standards that a BA must follow to ensure the reliability and safety of the grid. He asserted that must-take PURPA QF generation is affecting DEC's and DEP's ability to balance the amount of energy on the system with customer demand, especially during low load periods, particularly in DEP's service territory. Mr. Holeman stated that with almost 1,400 MW of solar generation in DEP's territory, much of which is PURPA must-take generation, Duke has identified several challenges associated with integrating all the energy created by these QFs, including: 1) managing "unscheduled" and "unconstrained" solar QF energy injections bounded by the Security Constrained Unit Commitment of reliable load following service; (2) managing the variability and intermittency of solar energy injections; (3) managing the growing amounts of operationally excess energy injected by solar facilities, particularly during spring, fall, and winter periods; and (4) ensuring compliance with NERC reliability standards, specifically including the BAL standards. According to Mr. Holeman, DEP can only ramp down its traditional generation to a certain level, the Lowest Reliable Operating Limit (LROL), to ensure that it will be able to ramp up fast enough in a controlled manner to maintain voltage and frequency levels to meet the generation to demand ratio as PURPA QF solar comes offline as the sun sets. If DEP is unable to ramp generation fast enough to meet demand, it could violate a NERC BAL Standard. If DEP ramps down its generation to the LROL but is still taking on energy from the PURPA QFs, it creates an excess energy event, which could also violate a BAL Standard. In the past, DEP has sold the excess energy to DEC through the Joint Dispatch Agreement (JDA) before a violation has occurred; however, use of the JDA in this manner is a non-firm economic resolution, and should not be construed as a firm operational mechanism to manage excess energy events. Mr. Holeman further testified on rebuttal that a new BAL Standard going into effect on January 1, 2018, will limit BAs from relying on a non-firm transmission path to balance their respective areas. This new BAL Standard will nullify DEP's planning ability to use the JDA to offload excess energy in order to stay within the NERC Standards during excess energy events. Mr. Holeman stated that there were 33 days in which excess energy events occurred in 2016 and 19 days in 2017, as of February 21; he stated that it is more likely than not that these occurrences would continue to rise as more and more PURPA QF solar is interconnected in the future. 2,200 MW are projected to be interconnected within the DEP BA by the start of 2018. These excess energy events and DEP's inability to ramp quickly enough once the QF solar generation starts or stops could cause DEP to violate a NERC BAL Standard. To prevent a violation of any applicable NERC Standards, Mr. Holeman asserted that the utilities' system operators should have operational control over these QFs, enabling the operators to curtail the QF generation in a nondiscriminatory way when facing an imminent NERC BAL violation. Ms. Bowman testified that DEC and DEP have proposed an amendment to their standard offer contract stating that a system emergency includes complying with any electric reliability organization or NERC/SERC regulations or standards.

Public Staff witness Metz testified that he agreed with Mr. Holeman that must-take energy from PURPA QFs is causing potential concerns within the DEP BA. He also agreed with Mr. Holeman that the utilities' limited ability to control PURPA QF solar generation creates challenges for BAs trying to match generation with load while staying within the limits required by NERC. Mr. Metz stated that

DEC and DEP already have language in their negotiated contracts that allows for a limited amount of curtailment each year through the use of a "Dispatch Down" instruction, but curtailment due to system emergencies does not count toward the limit. According to Mr. Metz, the Public Staff believes that the Federal Code already allows the utilities to curtail QFs when faced with an imminent violation of a NERC BAL Standard because an imminent violation of a NERC BAL Standard constitutes a system emergency as defined by 18 CFR 292.101(b)(4). Mr. Metz further testified that the Public Staff is in discussions with Duke about filing its processes and procedures for curtailing QFs in a non-discriminatory fashion.

NCSEA witness Johnson testified that the issues described by Mr. Holeman were legitimate, but viewed them as "growing pains"; he was troubled by Duke's solution of "declaring a system emergency when solar energy is displacing some of Duke's less flexible generating resources." (T. Vol. 7, pp. 319-22). Dr. Johnson believed that the proposal forces the QFs to shoulder too much of the risk because there is no limitation on how often an emergency can be declared or how much revenue a QF will lose. Dr. Johnson stated that two other options to help with the excess energy problem are for Duke to modify how it utilizes its pumped storage generation and to negotiate "Take or Pay" contracts with some of the solar QFs.

DISCUSSION AND CONCLUSIONS

18 CFR 292.101(b)(4) defines a system emergency as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." The Commission

agrees with the Public Staff that the imminent violation of any applicable NERC Standard would constitute a system emergency. 18 CFR 292.307(b) allows utilities to discontinue purchases from QFs if the "purchases would contribute to such emergency" and if the "discontinuance is on a nondiscriminatory basis." The Commission, therefore, determines that the utilities have had and shall continue to have the ability to curtail QFs when faced with a system emergency, which includes imminent violations of NERC Standards. Because the utilities have previously had the ability to curtail QFs when facing these situations, there is no need to amend the standard offer contract as proposed by witness Bowman and DEC and DEP in their Joint Initial Statement. The utilities shall file and keep current a document enumerating the procedures they will follow when faced with a system emergency. Further, the utilities shall also file quarterly report with the Commission documenting each time a utility is faced with or declares an imminent violation of a NERC Standard or any other type of system emergency that causes or potentially causes the utility to curtail QFs, that includes the following information: (1) whether the utility curtailed any QF(s); (2) the procedures leading up to the decision to curtail the QF(s); (3) how the utility determined which QF(s) to curtail; (4) the duration of the curtailment; (5) the duration of the system emergency; and (6) any other documentation required to be sent to any other state or federal agencies due to occurrence of a system emergency.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-23

The evidence supporting these findings of fact is found in the testimony of DNCP witness Gaskill, NCSEA witness Johnson, and Public Staff witness Metz.

DNCP witness Gaskill explained that in past proceedings, the Commission has approved a 3% line loss adder to the avoided cost payment for QFs connected to the distribution network because solar generation at that level can directly serve load on that circuit, avoiding transmission and transformer losses that would otherwise occur when serving that load. Mr. Gaskill testified that these savings only occur when the substation load exceeds the local distributed generation on a substation bus; however, when there is more solar generation on the distribution side of the substation than load, there is a backflow of power onto the transmission grid. This backflow negates the elimination of transmission line losses, and potentially results in an increase in system line losses. Mr. Gaskill provided an exhibit showing all 33 transmission substation transformers in DNCP's North Carolina territory: 11 showed a predominately constant backflow of power; 18 were "neutral," meaning that they either have a mix of forward and reverse power flows or that there is only a small amount of excess load remaining; and four circuits that showed a clear margin of load over currently interconnected solar on the distribution grid with the ability to host additional solar QFs. Given this situation, Mr. Gaskill testified that the 3% line loss adder should be eliminated from the standard offer contract avoided cost payments to QFs connected to the distribution grid.

Public Staff witness Metz provided the history of the line loss adder, stating that it first appeared in the avoided cost rate schedules of North Carolina Power (now DNCP), filed in Docket No. E-100, Sub 53, in 1987. The rate was last increased from 2.7% to 3% in the 2008 avoided cost proceeding. Mr. Metz testified that the Pubic Staff agrees with DNCP's proposal to eliminate the line loss adder from the standard offer contract based on the number of substations already experiencing power backflows and the number projected to experience power backflows in the future. Mr. Metz then stated that the Public Staff does not believe DEC or DEP should eliminate the line loss adder from their standard offer contract at this point, but should continue to evaluate the issue and include their findings in a study, or equivalent, during the next avoided cost proceeding.

NCSEA witness Johnson agreed that due to the backflow issue at the substations in certain areas that line losses are not avoided as much as in the past, but that the utilities do not take into account other benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs savings from not having to upgrade the transmission system itself. Dr. Johnson stated that in the Sub 140 proceeding, the Commission decided it should not include other cost and benefits of distributed solar in the avoided cost calculation until future studies and calculation methods have further developed.

SACE witness Vitolo testified that a QF which "flips" the substation from traditional flow to backflow will, in fact, reduce transmission line losses because there may still be a net reduction in power flow on the transmission grid. Dr. Vitolo proposed that the Commission require DNCP to calculate line loss avoidance with sufficient granularity to compensate renewable QFs for the value they provide with respect to line loss avoidance; if DNCP cannot calculate to that granularity, the Commission should continue to institute the 3% line loss adder.

On rebuttal, DNCP witness Gaskill testified that Dr. Vitolo's calculations of the power flows were not performed at the correct time and should have considered the state of the flows as they exist today, not an average throughout the year because (1) distributed generation was added to the substation throughout the year and (2) avoided cost rates are forward looking. In response to Dr. Johnson, Mr. Gaskill stated that DNCP has incorporated avoided costs that are reasonably known and quantifiable.

Mr. Snider on rebuttal testified that he agreed with Public Staff witness Metz that DEP should consider eliminating the line loss adder in future avoided cost proceedings because of the abundance of distributed generation.

DISCUSSION AND CONCLUSIONS

The Commission believes that DNCP has shown that backflows are occurring with enough regularity as to greatly reduce or nullify the benefits of the solar QFs line loss avoidances. Therefore, it is reasonable for DNCP to eliminate the line loss adder from its standard offer avoided cost payments to distribution-connected solar QFs. DEC and DEP shall continue to incorporate the line loss adder in their standard offer avoided cost calculations and should study their distribution substations and provide those results at the next avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact is found in the testimony of Duke witness Snider and Public Staff witness Hinton.

Duke witness Snider testified that while integration costs were a significant issue in the Sub 140 proceeding, DEC and DEP have not included incremental ancillary service costs driven by solar generation in the standard offer Schedule PP avoided cost rates, as those standard offer rates are proposed to be eligible only for QFs one MW and under. Mr. Snider stated that it may be necessary to address the ancillary service costs in future standard offer avoided cost filings if the future adoption rate of non-controllable QF solar continues at the present rate or increases, and if the further analysis by DEC and DEP of the costs and potential benefits of integrating these small solar generators onto their systems justifies their inclusion. Mr. Snider noted that DEC and DEP believe it is appropriate to address the costs of ancillary services and other integration costs related to QF generators in negotiated contracts.

Public Staff witness Hinton testified that these integration costs, which are not yet fully quantified, may lead to higher utility rates.

DNCP witness Gaskill echoed Mr. Hinton's testimony, stating that DNCP is studying the issue but has not yet quantified the costs with enough specificity to include them in the avoided cost rates at this time.

DISCUSSION AND CONCLUSIONS

Solar integration costs were thoroughly discussed in the last avoided cost proceeding, in which the Commission ultimately determined:

> [W]hile 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. Accordingly, the Commission concludes that it is premature for DEC, DEP and DNCP to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

The Commission agrees with the witnesses that the integration costs are not quantified precisely enough at this time to be included in avoided cost rates, but that they should continue to be evaluated, along with the benefits associated with solar generation, for potential future inclusion in standard offer contracts following review and approval by the Commission in a future avoided cost proceeding. To the extent the utilities intend to include integration costs in their negotiated contracts, they should first file a description of the adjustments and sample calculations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25 AND 26

The evidence supporting these findings is contained in the testimony of Duke witness Snider, DNCP witness Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Public Staff witness Hinton testified that in the Sub 140 proceeding, NCSEA witness Tom Beach proposed that the definition of off-peak hours be aligned with the load profile of solar QFs. The Commission did not adopt this proposal on the basis that it accounted for the benefits but not the costs associated with solar generation. Mr. Hinton asked the Commission to view this issue as a modeling or allocation issue where solar generation during off-peak hours is not being properly valued in rates. His calculations indicate that the avoided energy rate for solar would be 8% to 10% higher if the avoided marginal costs from solar generation during off-peak hours were taken into account. Mr. Hinton recommended that the utilities submit a solar-only rate.

NCSEA witness Johnson contended that more precise price signals better tailored to the most valuable hours in the winter and summer would be the best way to address operational issues attributable to North Carolina's rapid solar development.

Duke witness Snider testified that Duke had not included any incremental ancillary service costs attributable to solar generation in its standard offer rates, but it may be necessary to address these costs in future avoided cost proceedings.

In his rebuttal testimony, Mr. Snider noted that a solar-only rate would produce lower avoided cost rates than those filed in this proceeding. He stated that it is appropriate to use a solar-specific rate for larger QFs that takes into consideration the impact of solar generation on system operations. In response to Mr. Hinton's contention that off-peak solar rates would increase due to the diurnal profile coinciding with higher cost off-peak hours, Mr. Snider conducted an alternate analysis that calculated that the solar-only energy rate would be approximately 10% lower. Duke witness Bowman in rebuttal agreed with Public Staff witness Hinton and NCSEA witness Johnson that it was appropriate to take the costs and benefits attributable to solar into account in negotiating rates for larger QFs. She also stated that it may be reasonable to consider a solar-specific rate for smaller QFs in the next biennial proceeding.

In rebuttal testimony, DNCP witness Petrie disagreed with Public Staff witness Hinton that a solar-specific rate should be developed. He argued that the Public Staff proposal would account for a benefit of solar without factoring in the costs. Mr. Petrie contended that the Option B designation appropriately reflects the benefits of solar, and that DNCP's Schedule 19-LMP also matched a solar QF's generation profile with hourly prices.

DISCUSSION AND CONCLUSIONS

The Public Staff proposed the implementation of a solar-only rate to account for the specific characteristics of solar generation. NCSEA witness Johnson did not appear to oppose technology-specific rates, but proposed more targeted pricing signals as an alternative. Duke agreed that the costs of solar-specific technology should be factored into its negotiated rates. Duke is agreeable to developing a solar-only rate for standard contract QFs for the next avoided cost proceeding. However, Duke plans to incorporate both the costs and benefits of solar into this rate. DNCP disagreed with the Public Staff's proposal to require a solar-only rate, because it only incorporates benefits of solar and not costs, and because it contends that its existing schedules already account for technology-specific benefits.

The Commission agrees with the Public Staff that it is appropriate to require DEC, DEP, and DNCP to develop a solar-only rate for QFs eligible for the standard contract and file the rate in the next avoided cost proceeding. This rate should incorporate both the costs and benefits of solar, and be tailored to the specific characteristics of QF solar. It is also appropriate for the utilities to incorporate in negotiated avoided costs rates offered to larger QFs both the costs and benefits associated with a particular technology. Prior to doing so, however, the utilities shall file a description of the technology-specific adjustments and sample calculations in this docket for consideration.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27 AND 28

The evidence supporting these findings is contained in the proposed rates of WCU and New River. WCU and New River proposed to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution. This is the same approach approved by the Commission in Sub 140. No parties filed any comments or objections to WCU's and New River's proposals. DEC is WCU's requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation. The PPA between DEC and Blue Ridge expressly treats New River's native load as if it were Blue Ridge's native load for purposes of DEC's obligations vis à vis Blue Ridge.

The Commission concludes, based upon the foregoing, that WCU's and New River's rate proposals should be accepted and that the changes approved herein with respect to DEC's avoided capacity and energy rates should be reflected in WCU's and New River's long-term avoided cost rates. Specifically, the term of the standard contract will differ between hydroelectric QFs interconnected at distribution that are contracting to sell five MW or less and non-hydroelectric QFs that are contracting to sell one MW or less.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact is contained in the Joint Initial Statement of Duke, the testimony of Public Staff witness Lucas, the testimony of NCSEA witness Harkrader, and the direct and rebuttal testimony of Duke witness Freeman.

As outlined in the Joint Initial Statement of Duke, the Commission's current standard for the establishment of a LEO requires that a QF (1) self-certify with

FERC as a QF, (2) commit to sell its output to a utility under PURPA using the approved NoC, and (3) file an ROPC or receive a CPCN for the construction of the facility.

In its Joint Initial Statement, Duke proposed to add an additional requirement to the current LEO standard that a QF be either exempt from or have completed the System Impact Study of the interconnection process and executed and returned the Facilities Study Agreement. Duke also proposed a streamlined LEO NoC Form for small QFs of one MW or smaller, which would consist of (1) submission of an ROPC under R8-65, (2) submission of an Interconnection Request under Section 2 (20 kW Inverter Process) or Section 3 (Fast Track Process) of the NCIP deemed complete by the appropriate utility, and (3) a notice of commitment to sell the QF's output to DEC or DEP under the standard avoided cost rates.

In his direct testimony, Duke witness Gary Freeman asserted that under PURPA, the intent of a LEO is for a QF to make a legally enforceable commitment to sell its output to the utility. He argued that a QF should not be allowed to establish a LEO until it is able to make a binding commitment to sell its power to a utility. Mr. Freeman supported Duke's proposal by illustrating how a QF cannot make a commitment to sell until the QF is informed of its interconnection costs. Under Duke's view, the first "true" commitment of the QF to sell its output to a utility does not occur until the QF pays for the upgrades necessary for its interconnection, because prior to this point the QF does not have an obligation to develop the generation project. The current LEO standard that allows a QF to establish a LEO early in its development process coupled with the delays in the interconnection process create a gap between the time at which avoided costs are determined and when the QF begins delivering power to the utility, resulting in "stale" avoided cost rates.

In further support of Duke's proposal, Mr. Freeman cites the recent FERC decision FLS Energy, Inc., 157 FERC ¶ 61, 211 (2016) to emphasize the broad discretion states have in establishing a LEO, and that the LEO standard should focus on the QF's commitment and not the actions of the utility.

Public Staff witness Jay Lucas agreed with Duke's streamlined LEO process for small QFs of one MW or smaller. Mr. Lucas also proposed to include an additional requirement to the current LEO standard for non-standard QFs. He proposed that in order to establish a LEO, the QF must first be a Project A or B in the interconnection queue. The LEO would be established upon the earlier of (i) the QF's receipt of the utility's System Impact Study, or (ii) the passage of 105 days after the QF submits a complete interconnection request to the utility. For QFs that are not a Project A or B at the time the QF submits its interconnection request, the LEO is established upon the earlier of (i) receipt of the utility's system impact study for the QF, or (ii) 105 days after the QF becomes a Project A or Project B.

The Public Staff agreed that a QF owner lacks the ability to fully evaluate the feasibility of a project until it receives its System Impact Study results.

However, Mr. Lucas pointed out that the timing and control of the interconnection process is also largely up to the utility. Under the NCIP, a utility has 105 days to provide a QF with a System Impact Study. With the current delays in the interconnection queue, the actual time required for these studies has varied with some projects waiting far longer than 105 days for receipt of the study. Moreover, the QF has no control over when it will receive its System Impact Study; the timing of the study is solely in the hands of the utility. Tying the establishment of the LEO to completion of the System Impact Study step of the interconnection process as proposed by Duke would allow the utility to determine if and when a LEO is established. Mr. Lucas stated that Duke's proposal would be inconsistent with the decision in FLS Energy, Inc. that held that allowing the utility to control whether or not a LEO is established is contrary to PURPA and FERC regulations.

NCSEA witness Harkrader suggested a proposal similar to the proposal of the Public Staff, and emphasizes that the timing of the LEO should not be controlled by the utility. Ms. Harkrader proposed that the LEO be established only after 105 days has lapsed from the utility's receipt of the QF's interconnection request. Ms. Harkrader also outlined the various significant commitments a QF makes in the development process prior to the receipt of the System Impact Study, including site control and the securing of land use and regulatory approvals.

DISCUSSION AND CONCLUSIONS

The Commission acknowledges that due to delays in the interconnection queue QFs have been able to establish a LEO well before the date the QFs are able to generate power. As stated in the testimony of Public Staff witness Lucas, some QFs are able to establish LEOs two to four years before their power delivery date. It is appropriate to bring the LEO date into closer alignment with the date a QF is able to generate power to deliver to the utility by moving the LEO date to a point further along in the interconnection process.

As outlined in the testimony of the Public Staff and NCSEA, a QF owner does indicate its commitment at multiple points in its project development prior to executing a PPA with a utility. Although an executed PPA is one type of commitment, the QFs demonstrate their commitment by paying a substantial deposit when submitting an interconnection request, completing a detailed interconnection request application, and obtaining site control.

It is not appropriate to establish a new standard that would allow the utilities to control the timing of the establishment of a LEO. Although the current delays in DEC's and DEP's interconnection queues are not solely their responsibility, as acknowledged in their testimony, the interconnection queue is generally under the control of the utilities. Tying the establishment of a LEO to the receipt of the System Impact Study would allow the utilities to control the establishment of the timing of the LEO and would be inconsistent with the FERC decision in FLS Energy, Inc.

It is also not appropriate to establish a LEO standard based on the delays in the interconnection queue currently being experienced, which may be short lived. As Public Staff witness Lucas pointed out, the concern over premature establishment of LEOs will lose significance if the delays in the interconnection queue are reduced. While the utilities are not penalized for not meeting the timeframes in the NCIP, the Commission expects the utilities to make their good faith efforts to meet the timeframes.[26] Duke witness Freeman testified on cross-examination that the circumstances of the DEC and DEP interconnection queues are unique to North Carolina.

Since North Carolina's current LEO standard is unique to North Carolina, a revised LEO standard should reflect the current circumstances being experienced in North Carolina, while being consistent with PURPA and FERC regulations. The Commission notes footnote 33 of FLS Energy, Inc. provides:

> When a state commission believes that a previously-determined avoided cost rate is no longer an accurate measure of a utility's avoided costs, the appropriate response is not to establish a standard for a legally enforceable obligation that is inconsistent with PURPA and the Commission's regulations under PURPA, but instead to determine a new avoided cost rate that better reflects the utility's avoided costs consistent with the requirements and procedures identified in the Commission's regulations under PURPA. (citations omitted)

The Commission believes that the rates established herein should more accurately measure the utilities' avoided costs, and that the revisions to the LEO standard should comply with PURPA and FERC regulations and reflect conditions in North Carolina.

[26] The Commission notes that the interconnection procedures are currently under review in Docket No. E-100, Sub 101. Should the timeframes for receipt of the System Impact Study be adjusted, the timeframes for establishment of a LEO should be adjusted accordingly.

The Commission concludes that it is appropriate to add an additional requirement to the current LEO standard for QFs one MW and above that are not eligible for the standard contract. For these QFs, a LEO is established when (1) the QF has self-certified with FERC as a QF, (2) the QF has made a commitment to sell the QF's output to a utility under PURPA using the approved NoC Form, (3) the QF has filed an ROPC or received a CPCN for the construction of the facility, and (4) the QF has submitted a completed interconnection request pursuant to the NCIP. The date on which the commitment to sell is established for a QF larger than one MW that has been designated as an A or B project in the interconnection queue shall be the earlier of (i) 105 days after the submission of the interconnection request, or (ii) upon the receipt of the system impact study from the public utility. The date on which the commitment to sell for a QF larger than one MW that has not been designated as an A or B project at the time of its interconnection request shall be the earlier of (i) 105 days after the project has been designated as an A or B project, or (ii) upon the receipt of the system impact study from the public utility.

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

The evidence supporting these findings of fact is contained in the Joint Initial Statement of Duke, the testimony of Public Staff witnesses Hinton and Lucas, the testimony of NCSEA witness Harkrader, and the direct and rebuttal testimony of Duke witness Freeman.

In his direct testimony, Duke witness Freeman proposed a process for the development of procedures for the negotiation of PPAs for projects above one MW. The procedures for the negotiation of non-standard PPAs would be developed with the Public Staff and other interested parties. The key components of this process as outlined by Mr. Freeman would include: (1) the right to commence negotiation by submission of project information and request for non-binding indicative pricing and draft PPA, (2) the delivery of current indicative pricing and a draft PPA by the utility to the QF within 30 days of request, (3) the indicative pricing provided by the utility being available for 60 calendar days after delivery, (4) after negotiation of the final PPA, the delivery of an executed PPA to the utility by the QF within 15 calendar days, (5) a scheduled commercial on-line date and penalties for failure to deliver power by that date in the PPA, and (6) a 60 calendar day post-execution due diligence period for the QF to rescind its PPA without facing liquidated damages.

Public Staff witness Hinton agreed that a process should be developed to streamline the process for negotiating PPAs not eligible for the standard contract. The key components of the process outlined by the Public Staff include: (1) specific timeframes for both parties to provide information and responses, (2) a standardized contract form that would allow clear delineation of proposed changes and points of negotiation, (3) the availability of indicative pricing for a sufficient period to allow the QF to evaluate project viability and obtain financing, and (4) the opportunity for either party to seek informal resolution of disputes, or seek arbitration with the Commission.

NCSEA witness Harkrader agreed that a standardized contracting process could provide certainty while minimizing transaction costs and the need for negotiations. However, she stated that without express limitations on the discretion of the utilities regarding the term or duration of a fixed rate, any standardized process would result in disputes and litigation.

In his rebuttal testimony, Duke witness Freeman proposed to revise the NoC form for non-standard offer QFs into a form that provides the QFs the ability to give notice for negotiation of a PPA. DEC and DEP propose to accept input from the Public Staff, DNCP, and other interested parties to refine this form.

Public Staff witness Lucas also proposed to limit QFs that withdraw a previously submitted NoC from being able to establish a new LEO for two years from the date of withdrawal. If avoided costs begin to increase, a QF may want to delay the establishment of a LEO in order to take advantage of higher rates. For the two year time period that a QF that has withdrawn from its NoC, the QF would be limited to the utility's "as available" energy rates.

Duke witness Freeman agreed with this proposal in his rebuttal testimony, and recommended its approval for small QFs eligible for the standard offer.

DISCUSSION AND CONCLUSIONS

The Commission acknowledges that due to the reduction in the size of projects that are eligible for the standard contracts, there may be an increase in the number of negotiated contracts. It is appropriate to develop a standardized process for these negotiations in order to reduce potential disputes and arbitrations before the Commission. However, it is premature to approve the form suggested by Duke without input from DNCP and other interested parties. Therefore, the Commission directs DEC, DEP, DNCP, and other interested parties to form a working group to develop procedures for the negotiation of non-standard PPAs for projects above one MW. The working group should propose revisions to the NoC form to recognize the differences between the LEO standard for projects sized one MW and below and projects sized above one MW.

Lastly, the Commission finds that it is appropriate to limit QFs to "as available" energy rates for a period of two years should a QF withdraw a NoC. Therefore, the NoC Form should also be revised to reflect the consequences of withdrawal of a previously submitted NoC form.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DNCP shall offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods as standard options to hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should 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 consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration.

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

3. That DNCP shall continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's Sub 106 Order.

4. That DEC, DEP, and DNCP shall offer QFs not eligible for the standard long-term levelized rates the following three options: (a) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's

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

5. That DEC and DEP shall recalculate their avoided energy rates using forward natural gas prices for no more than five years before transitioning to their fundamental forecasts for the remainder of the planning period.

6. That to the extent the utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations.

7. That DEC and DEP should recalculate their avoided capacity rates using seasonal allocation weightings of 60% winter and 40% summer.

8. That DEC and DEP shall remove the amendments to their standard offer contract to incorporate the imminent violation of a NERC BAL Standard into the system emergency provision, since the utilities' standard offer contract already allows to curtail QFs in a system emergency, as defined in 18 CFR 292.307(b).

9. That the utilities shall file procedures with the Commission stating how the utilities would curtail QFs on a nondiscriminatory basis in accordance with 18 CFR 292.307 when there is a system emergency within 60 days of this order.

10. That the utilities shall file reports to the Commission and Public Staff on a quarterly basis, detailing the instances in which the utility curtailed QFs, the reasons for the curtailments, and the data supporting the curtailment. The first quarterly report shall be due no later than ______________, 2017.

11. That a PAF of 1.16 shall be utilized by DEC, DEP and DNCP (for its Schedule 19-FP) in their avoided cost calculations for QFs except for hydroelectric facilities with no storage capability and no other type of generation.

12. That a PAF of 2.0 shall be utilized by DEC, DEP and DNCP (for its Schedule 19-F) in their respective avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued in accordance with the stipulation filed by DEC, DEP and the NC Hydro Group.

13. That DEC, DEP, and DNCP shall not incorporate the costs and benefits related to solar integration in their avoided cost calculations until such time

that future studies and developments have been concluded and the Commission has approved such inclusions.

14. That DNCP shall eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network.

15. That DEC and DEP shall continue to include the line loss adder in their avoided cost payments, but shall study the effects of solar QFs on their distribution grid to determine if there is sufficient backflow at their substations to eliminate the line loss adder from their standard offer avoided cost calculations during the next avoided cost proceeding.

16. That the utilities shall update their NoC Form within 30 days after the date of this Order, to be used by all QFs to show their compliance with the test to establish a LEO.

17. That the utilities shall place the LEO form and information on their websites that clearly shows how to establish a LEO, as amended by this Order, and which departments must be contacted to negotiate interconnection agreements and PPAs. The utilities shall file within 30 days of the issuance of this Order a description of the location of the forms and information on their respective websites and the Public Staff is requested to review this filing and recommend to the Commission if the information is clearly accessible and identifiable within ten days of the utilities' filing.

18. That the utilities and other interested parties shall form a working group to develop procedures for the negotiation of non-standard PPAs for projects above one MW. No later than ______________, 2017, DEC, DEP, and DNCP shall file a report with the Commission documenting the discussions that took place in the working group and any consensus procedures that were reached in order to help streamline and improve the efficiency of the negotiated PPA process.

19. That WCU and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed ten-year avoided capacity rates.

20. That the utilities are required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 30 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ______________, 2017.

NORTH CAROLINA UTILITIES COMMISSION

M. Lynn Jarvis, Chief Clerk