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September 18, 2015

Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603 – 5918

Re: NCSEA's Proposed Order
NCUC Docket No. E-100, Sub 140

Dear Ms. Mount:

Enclosed for filing in the above-referenced docket is NCSEA's Proposed Order.

Should you have any questions or comments, please do not hesitate to call me. Thank you in advance for your assistance and cooperation.

Regards,

/s Charlotte Mitchell

4851-4743-9144, v. 1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	NCSEA'S
Electric Utility Purchases from	)	PROPOSED ORDER
Qualifying Facilities – 2014	)	

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Susan W. Rabon, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

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

Kendrick C. Fentress, Duke Energy Corporation, Post Office Box 1551, Raleigh, North Carolina 27602

For Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

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Andrea R. Kells, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27611

For North Carolina Sustainable Energy Association:

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Steven Levitas, Kilpatrick Townsend, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27612

For Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Chapel Hill, North Carolina 27516

For North Carolina Waste Awareness Reduction Network:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Environmental Defense Fund:

John Finnigan, 128 Winding Brook Lane, Terrace Park, Ohio 45174

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

Adam Olls, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For The Alliance for Solar Choice:

Thad Culley, Keyes, Fox & Weidman, LLP, 401 Harrison Oaks Boulevard, Cary, North Carolina 27613

For Google, Inc.:

Jo Anne Sanford, Sanford Law Office, PLLC, PO Box 28085, Raleigh, North Carolina 27611

For the Using and Consuming Public:

Lucy Edmonson and Tim R. Dodge, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On February 25, 2014, in the above captioned docket, the North Carolina Utilities Commission (the Commission) issued its Order Establishing Biennial Proceeding and Scheduling Hearing (the 2014 Proceeding), held pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings also are held pursuant to the responsibilities delegated to this Commission under G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of co-generation and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

With respect to electric utilities subject to state jurisdiction, the FERC delegated the implementation of these rules to the state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules. To this end, the Commission has determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA.

This proceeding also is a result of the mandate of G.S. 62-156, which 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 the 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 MW or less, thus excluding users of other types of renewable resources.

For the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (the 2012 Proceeding),[1] the Commission initiated the 2014 Proceeding in advance of the filing of new proposed rates, stating that such filing would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing to consider changes to the method used to calculate avoided cost payments (i.e., the first phase of the 2014 Proceeding). Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU), and New River Light and Power Company (NRLP) were made parties to the proceeding. The Commission established May 30, 2014, as the deadline for interventions by interested persons; set the evidentiary hearing for July 7, 2014, at 1:30 p.m.; and required that direct testimony and exhibits regarding the proper method to determine avoided cost rates, particularly capacity rates, be filed by April 17, 2014, that responsive testimony be filed by May 30, 2014, and rebuttal testimony by June 20, 2014.

The following parties intervened with the permission of the Commission: the North Carolina Sustainable Energy Association (NCSEA); the Carolina Utility Customers Association, Inc.; the Carolina Industrial Group for Fair Utility Rates I, II, and III; the North Carolina Waste Awareness and Reduction Network; the Environmental Defense Fund; the Southern Alliance for Clean Energy (SACE); the North Carolina Hydro Group; The Alliance for Solar Choice; the Public Works Commission of the City of Fayetteville; the North Carolina Chapter of the Sierra Club and the Natural Resources Defense Council; and Google, Inc.

Following the evidentiary hearing, the Commission issued an Order Setting Avoided Cost Parameters on December 31, 2014 (the Order Setting Parameters). The Order Setting Parameters, among other things, established certain parameters by which avoided cost rates should be calculated and required that DEC, DEP, DNCP, WCU, and New River file proposed avoided cost rates 60 days from the issuance of the Order (by March 2, 2015).

On January 8, 2015, the Commission issued the Order Establishing Procedural Schedule and Scheduling Public Hearing, which allowed additional parties, in addition to those that intervened pursuant to the original intervention deadline, to become formal participants to the proceeding. In addition, the order directed the electric utilities to file their proposed rates and standard form contracts in accordance with the Order Setting Parameters. Given the evidence already presented and considered in this docket, the issues generally pertinent to proceedings to determine avoided costs, and the Order Setting Parameters, the Commission elected to resolve all remaining issues based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and on written comments on the statements, exhibits and

1 See generally Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 136, February 21, 2014 (the 2012 Order).

schedules, without conducting another full evidentiary hearing for the purpose of receiving expert testimony (i.e., the second phase of the 2014 Proceeding).

Pursuant to the Order Establishing Procedural Schedule and Scheduling Public Hearing Commission and subsequent procedural orders of record, the Commission established May 4, 2015 as the deadline for interventions by interested persons other than those already intervened; set the public hearing for May 19, 2015, at 9:30 a.m.; directed all parties, other than the five electric utilities, to file the comments and exhibits that they wish to present in this proceeding on or before June 22, 2015; directed the electric utilities and intervenors to file reply comments on or before August 7, 2015; and directed the electric utilities and intervenors to file proposed orders on or before September 18, 2015.

On February 27, 2015, WCU and NRLP filed their respective proposed standard rates and contracts. On March 2, 2015, DEC, DEP and DNCP (collectively, the Utilities) filed their respective proposed standard rates and contracts (the March 2015 Filings). On June 22, 2015, the Public Staff filed the Initial Statement of the Public Staff (Public Staff Initial Statement); NCSEA filed Initial Comments by NCSEA (NCSEA's Initial Comments); and SACE filed Initial Comments of Southern Alliance for Clean Energy. On August 7, 2015, DEC and DEP filed Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Reply Comments (DEC/DEP Reply Comments); DNCP filed Reply Comments of Dominion North Carolina Power (DNCP Reply Comments); the Public Staff filed the Reply Comments by the Public Staff (Public Staff Reply Comments); NCSEA filed Reply Comments by NCSEA (NCSEA Reply Comments) and Affidavit of Ben Johnson, Ph.D. (Johnson Affidavit); and SACE filed Reply Comments of Southern Alliance for Clean Energy.

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

FINDINGS

1. It is appropriate for DEC, DEP, and DNCP to offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year as standard options to (a) 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 and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass 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. DEC, DEP, and DNCP should offer their standard five-year levelized rate option to all other QFs contracting to sell three MW or less capacity.

2. It is appropriate for DNCP to offer, as an alternative to avoided cost rates derived using the peaker methodology, avoided cost rates based upon market clearing prices derived from the markets operated by PJM 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.

3. DEC, DEP, and DNCP must offer QFs not eligible for the standard long-term levelized rates the following three options if the electric utility has a Commission-recognized active solicitation: (a) participating in the electric utility's competitive bidding process, (b) negotiating a contract and rates with the electric utility, or (c) selling energy at the electric 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 should 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. When developing fuel forecasts for the purposes of calculating avoided energy costs, it is inappropriate for the Utilities to employ different methodologies from those used in their respective 2014 Integrated Resource Plans (IRP) and, in doing so, place greater emphasis on forward prices, which results in substantially lower avoided energy costs than if they had used the same methodologies used in their 2014 IRPs.

5. When running the production cost models to generate avoided energy costs, it is inappropriate for the Utilities to use generation expansion plans that take into account a cost of carbon dioxide emissions controls until such cost is known and verifiable.

6. In calculating avoided energy costs, the Utilities have not adequately accounted for fuel price hedging benefits that result from the substitution of renewable generation for fossil fueled generation.

7. The Utilities have failed to comply with the Commission's directive that when applying the peaker methodology to calculate their avoided costs, the installed cost of a combustion turbine (CT) must be calculated using "data from publicly available industry sources" that may be adjusted "only to the extent clearly needed to adapt any such information to the Carolinas and Virginia."

8. It was inappropriate for DNCP to substitute the lower cost Siemens CT in place of the GE 7FA CT used in the industry source on which the utility relied.

9. It was inappropriate for DEC and DEP to substitute a lower contingency factor in place of the contingency factor used in the industry source on which the utilities relied.

10. In this 2014 Avoided Cost Proceeding, it was appropriate for DNCP to substitute longer useful CT life in place of the useful CT life used in the industry sources on which the Utilities relied because such assumption was supported by a detailed study, filed for public inspection with the Commission. It was not appropriate for DEC and DEP to substitute a longer useful CT life in place of the useful CT life used in the industry source on which the utilities relied because there is no detailed study supporting the useful life assumption on file for public inspection with the Commission.

11. The Utilities inappropriately included economies of scope when calculating the installed cost of a CT.

12. It is inappropriate for DEC, DEP and DNCP to modify the weighting given to summer and non-summer months in calculating rates to reflect the historical percentage breakdown of annual CT production when using the peaker method to calculate avoided costs.

13. It is inappropriate for DNCP to include the following provisions in its standard Agreement for the Sale of Electrical Output to Virginia Electric and Power Company (DNCP PPA) and Schedule 19 (DNCP Rate Schedule):

a. The provision limiting assignment rights is unreasonable and must be revised to provide that consent to assignment will not be unreasonably withheld by DNCP.

b. DNCP's proposal to give DNCP the right to terminate—with no opportunity to cure—if a QF does not commence construction by a date certain, is inappropriate.

c. DNCP's terminology related to "net capacity" and "net electrical capacity" is unclear.

d. DNCP's proposal to increase the availability limitation from one-half mile to one mile is unjustified and unnecessary. An availability limitation that is not limited to facilities that use the same energy resource is also unjustified and unnecessary.

e. DNCP's elimination of site specific line loss allowance is unnecessary, given that the QF bears all associated expense.

f. DNCP's classification of failure to provide consecutive status reports as an incurable event of default is unreasonable. DNCP's classification of the failure to maintain an interconnection agreement in full force and effect, without exception for breach by a party other than the QF, as an incurable event of default is unreasonable. DNCP's proposal to include granting by the FERC of a PURPA Section 210(m) waiver as grounds for termination is unnecessary.

g. DNCP's terminology related to "net capacity" and "net electrical capacity" is unclear.

h. DNCP's proposal to increase the availability limitation from one-half mile to one mile is unjustified and unnecessary. An availability limitation that is not limited to facilities that use the same energy resource is also unjustified and unnecessary.

i. DNCP's elimination of site specific line loss allowance is unnecessary, given that the QF bears all associated expense.

j. DNCP's classification of failure to provide consecutive status reports as an incurable event of default is unreasonable. DNCP's classification of the failure to maintain an interconnection agreement in full force and effect, without exception for breach by a party other than the QF, as an incurable event of default is unreasonable. DNCP's proposal to include granting by the FERC of a PURPA Section 210(m) waiver as grounds for termination is unnecessary.

14. With respect to the proposed revisions by DEC and DEP to their respective standard Purchase Power Agreement (DEC/DEP PPA), Terms and Conditions for the Purchase of Electric Power (DEC/DEP Terms and Conditions), or Rate Schedule, the Commission finds as follows:

a. The 30-month deadline for achieving commercial operation, as revised per agreement with NCSEA to include qualifying language, is appropriate.

b. The commencement provision in the DEC/DEP PPA, as revised per agreement with NCSEA to include qualifying language, is appropriate.

c. The reduction in contract energy charge and reduction in contract capacity charge provision is inconsistent with previous rulings of the Commission and must be struck.

d. A lack of opportunity to cure for those events of default identified in the DEC/DEP Terms and Conditions—other than unauthorized use of the meter—is commercially unreasonable, but the resolution on the issue of cure periods reached with NCSEA is reasonable.

e. It is unreasonable for DEC and DEP to retain sole discretion over whether to consent to a QF's assignment of rights.

f. The provisions in the standard offer documents related to the effect of subsequent government action on terms and conditions must be revised to clarify that such action will not change the rates or the terms and conditions of prior-executed power purchase agreements.

g. It is appropriate for DEC and DEP to revise their standard documents as resolved with NCSEA, to clarify that when a QF is subject to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101 and, accordingly, has entered into an interconnection agreement, the interconnection agreement controls in the event of a conflict with the standard offer.

h. The standard offer documents must be revised to clarify that QFs are required to operate at a power factor of "unity," that when not operating at unity they will be charged for the delivery or consumption of VARs at a specified rate, and that QFs that have entered into an Operating Agreement shall be governed by the terms and conditions of that Operating Agreement.

i. The proposal to limit availability of the Rate Schedules to QFs located on a "single, contiguous premise" is inappropriate.

j. The provision related to QF reporting requirements, as revised per agreement between the Public Staff and DEC and DEP, as further revised to reflect that QFs that rely on variable resources shall be held harmless if such production estimates are in error due to factors beyond their control such as the availability of solar, wind or streamflow, is appropriate.

15. It is appropriate to use a simple form as a means, but not the exclusive means, to establish that a QF has committed to sell its output to the utility.

16. DEC and DEP have failed to comply with the requirement of section 292.302(b) of the FERC's regulations that certain data underlying an electric utility's avoided cost calculation be filed for public inspection.

DISCUSSION AND CONCLUSIONS FOR FINDING NOS. 1-3

Whether the Commission should require the electric utilities to offer long-term levelized rates to QFs as standard rate options was addressed by the parties during the first phase of this proceeding. Based on the evidence in the record during the first phase, the Commission found that it is appropriate to retain the five MW threshold and 15-year maximum term length for the standard offer. In addition, the Commission concluded that 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 (a) hydroelectric QFs owned or operated by SPPs contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity.

Therefore, the Commission concludes that DEC, DEP, and DNCP's March 2015 Filings appropriately offer long-term levelized rate options of five, ten, and 15-year terms to hydro QFs contracting to sell five MW or less and to QFs contracting to sell five MW or less that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass. The Commission further concludes that DEC, DEP, and DNCP March 2015 Filings appropriately offer their five-year levelized rate options to all other QFs contracting to sell three MW or less capacity. With these limitations on the standard offer, long-term contract options serve important statewide policy interests while reducing the utilities' exposure to overpayments and should continue to be made available.

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

Consistent with the 2012 Order, DNCP proposed to continue to offer Schedule 19-LMP as an alternative available to QFs. DNCP explained that energy prices are based on the hourly PJM Dom Zone Day Ahead Locational Marginal Price ("DA LMP") expressed as $/MWh. For QFs that are providing energy and capacity, the DA LMP values, divided by 10 (to derive a cents per kWh price), are applied to the respective hourly net outputs of the QF generation. The Commission concludes that it is appropriate for DNCP to offer avoided cost rates based upon market clearing prices derived from the markets operated by PJM. As it has done in past proceedings, the Commission directs DNCP to calculate avoided cost payments under both methods used for the next two years and report the resulting comparison to the Commission.

The Commission concludes that DEC, DEP, and DNCP should continue to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations or, when explicitly approved by Commission Order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission. Under PURPA, a larger QF is just as entitled to full avoided costs as a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules is not intended to suggest otherwise.

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 available complaint process. The Commission concludes that the arbitration option should be preserved.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 4

In calculating avoided energy costs, fuel price forecasts generally have the greatest impact on cost. Neither DEC, DEP nor DNCP used the same methodology for forecasting natural gas prices for the purposes of this proceeding that they used in their respective 2014 IRPs. The Public Staff explained the importance of consistency between the IRP and the avoided cost filings as follows:

> One of the most important issues in these biennial proceeding continues to be the need for consistency with the utilities' IRPs. The

> avoided energy costs are generated from production cost models utilizing the utilities' current resources combined with their future resource expansion plans as derived in the IRPs. In this proceeding, the interval between the two filings was slightly longer than normal; nonetheless, the fuel forecasts and other data inputs should be fairly equivalent. The assumptions used in the utilities' IRPs and their avoided cost calculations are often the same or very comparable given the similarities in the two key computer models used in the proceedings.

Public Staff's Initial Statement, p. 26. In this proceeding, the Utilities have changed the forecast methodology to include a longer time period of reliance on forward prices and a shorter period of reliance on their long-term fundamental forecasts, when compared to the methodology used in the 2014 and earlier IRPs, which rely on just a few years of forward prices, combined with a longer period of reliance on long-term fundamental forecasts. Public Staff Initial Statement, p. 33; Johnson Affidavit, paragraphs 15-21.

NCSEA affiant Johnson recommended that the Commission reject the Utilities' overreliance on forward price data for four reasons: 1) forward prices are not accurate predictions of, or a reliable indicator of what actual commodity prices will be in the future; 2) additional costs would need to be added to the "forward prices" if the Utilities were to purchase futures contracts in an effort to "lock-in" current prices for fuel to be delivered and burned in the future; 3) futures-based "forward" prices used by the Utilities are substantially lower than, and inconsistent with, the long term historical trend in prices; and 4) under current circumstances it would be particularly unreasonable to place heavy reliance on the current low level of "forward prices" because the upside price risks are greater than the downside risks (prices are more likely to go up than go down in the current situation), and in fact, prices might be near the bottom of a cyclical downturn, in which case prices could move sharply higher, or move back toward or above the long term trend line, within the next few years. Johnson Affidavit, paragraph 26.

In addition, NCSEA pointed out that by emphasizing unusually low forward prices, the Utilities ignored the high probability of an upswing in gas prices and disregarded the possibility these spot prices may be a temporary aberration. NCSEA pointed out that in doing so, the Utilities have greatly increased the risk that the actual costs they will incur when producing electricity using their own generating units will be substantially higher than their avoided energy cost estimates. NCSEA concluded that by abandoning the method used in the 2014 (and previous) IRP proceeding and by ignoring the possibility that fuel prices may soon revert to the long term trend line, the Utilities have reduced their avoided energy cost estimates to an unreasonably low level. NCSEA Initial Comments, section I.3.

Further, NCSEA argued that the change in methodology is not an improvement, since forward prices are not a more accurate or reliable basis for predicting prices in the future. NCSEA affiant Johnson explained that fundamentals-based forecasts, like the ones the Utilities have traditionally relied upon, are the most reliable and consistent basis for estimating prices that will actually be paid for fuel that will be purchased and burned in future years. Johnson explained that fundamental forecasts are based upon a detailed analysis of historical price trends, contributing factors that influence prices, and the interaction between different fuel markets, among other "fundamental" factors. Johnson Affidavit, paragraph 22. As a result, fundamentals-based forecasts better approximate what is needed in this proceeding – i.e., a prediction of prices that will actually be paid by the Utilities in the future. Johnson Affidavit, paragraph 22.

Similarly, the Public Staff noted that an over-reliance on forward price data calls into question the reliability of the long-term forecasts. Public Staff Initial Statement, p. 30. The Public Staff noted that some use of futures market data might be appropriate for the short-term, but only to the extent that the markets are viewed as liquid and the volumes being transacted reflect an active market for the commodities in question. Public Staff Reply Comments, p. 3. As an example, the Public Staff explained that the relatively small number of contracts for coal futures reflect limited liquidity in the market and indicate that little confidence can be placed in the reasonableness of a particular forward price and that a similar degree of illiquidity is observed with long-term natural gas futures contracts. Public Staff Reply Comments, p. 3. The Public Staff warned that while forward market prices may provide a snapshot of current future prices, they do not represent the same level of analysis and consideration given to the development of long-term forecasts, as performed by the U.S. Department of Energy - Energy Information Agency (EIA), Moody's Investor Services, Inc., Global Insight, Inc., and other firms whose expertise is in forecasting. Public Staff Reply Comments, p. 3. Finally, the Public Staff pointed out that the utilization of forward prices is not consistent with the fuel procurement practices of the Utilities and thus does not provide an accurate representation of the Utilities' future fuel costs. Public Staff Reply Comments, p. 3.

With respect to DEC and DEP, the Public Staff concluded that DEC's and DEP's overreliance on forward prices "actually lowers avoided energy costs." Public Staff's Initial Statement, p. 33. The Public Staff recommended that the Commission require DEC and DEP to reconstruct their natural gas and coal price forecasts using only five (5) years of forward price data, consistent with the approach utilized in their 2014 IRPs, and re-calculate their avoided energy cost using the reconstructed forecasts. Public Staff Initial Statement, pp 29-31; Public Staff Reply Comments, pp 3-4. In addition, the Public Staff recommended that, to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in proceedings before the Commission, they make those proposals in the biennial IRP proceedings, which provide the basis for support for certificates of public convenience and necessity CPCNs and avoided costs over the subsequent year. Public Staff Reply Comments, p. 4.

While NCSEA expressed general support for the Public Staff's recommendation of using no more than five (5) years of future markets data in the fuel price forecasts, NCSEA recommended that DEC's and DEP's actual 2014 IRP fuel forecasts be used to recalculate their avoided energy costs in order to achieve PURPA's objective of ratepayer indifference. NCSEA Reply Comments, section I.A. NCSEA acknowledged that the Commission unquestionably emphasized, in its Order of Clarification, that the Utilities should use "up-to-date data in determining the inputs" for avoided cost rates. Although the 2014 IRP fuel price forecasts were developed in conjunction with the September 2014 filing deadline for the IRPs, NCSEA pointed to three reasons why the Commission should direct DEC/DEP to use their 2014 IRP fuel forecasts in the recalculation of avoided energy costs. NCSEA Reply Comments, section I.A. First, DEP relied on its 2014 IRP fuel price forecasts on April 25, 2015 to support its application for a certificate of public convenience and necessity (CPCN) to construct the 84 MW Sutton blackstart CT (Sutton Blackstart CT Project), an application that was made subsequent to DEC's and DEP's March 2015 Filings. Second, DEC's and DEP's Avoided Cost Informational Filing, filed in this docket on December 23, 2014 (DEC/DEP Informational Filing) pursuant to their obligations under PURPA, used the same simulation run and input assumptions to calculate avoided energy costs as had been used in their 2014 IRPs. Third in the context of DEP's recent request for permission to acquire the ownership interests of the North Carolina Eastern Municipal Power Agency in certain generating facilities—which was filed with the Commission Docket No. E-2, Sub 1067, on April 13, 2015, subsequent to the March 2015 Filing—the 2014 IRP data were used to calculate the future fuel savings to DEP customers, which DEP relied on to justify its request.

The Commission is persuaded that DEC's and DEP's consistent use of the 2014 IRP fuel price forecasts both prior to and subsequent to their March 2015 Filings necessitates a conclusion that DEC and DEP must be directed to use the same fuel price forecasts in this proceeding as they used in their 2014 IRP filings.

With respect to DNCP, the Public Staff and NCSEA took the position that DNCP's change in the weightings of the fundamental forecast and futures market data resulted in different avoided energy cost rates than its approach utilized for developing fuel forecasts in its 2014 IRP. Public Staff Reply Comments, p. 4; Johnson Affidavit, paragraphs 16-17; 22-26. NCSEA took the position that the Commission must reject DNCP's use of different fuel price forecasts in the IRP proceeding and the avoided cost proceeding, for the same reasons NCSEA has given in the context of DEC and DEP. NCSEA Reply Comments, section I.B. For the reasons noted by NCSEA affiant Johnson, the Commission concludes that DNCP's change in methodology from the IRP proceeding to this proceeding was inappropriate and must be rejected.

The Commission is concerned, for the reasons expressed by NCSEA affiant Johnson as well as the Public Staff, about the Utilities' overreliance on forward price data. In this proceeding, avoided energy costs are calculated using the Utilities' future resource expansion plans set forth in the IRP, in order to most accurately approximate the generation that will be avoided by the utility. As such, the fuel price forecast methodology used to create the Utilities' IRPs should be used in this proceeding, with minimal updates, to maintain consistency. Here, however, given the Utilities' repeated reliance on the actual IRP forecasts subsequent to the March 2015 Filings, the Commission concludes that, not only must the Utilities use the same methodology for calculating fuel price forecasts as used in the IRP, the Utilities must use the actual forecasts used in the IRP

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 5

In the Order Setting Parameters, the Commission concluded as follows:

> While the EPA has proposed to regulate CO2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time. The end result of the proposed regulations is speculative at best, and, as Public Staff Hinton noted, the Commission has previously concluded that "[q]uantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." If and when such costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time. However, in the present case, the Commission agrees with the Public Staff that it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable.

Order Setting Parameters, p. 44. To this end, the Commission ordered "[t]hat the generation expansion plans used in the avoided cost production cost models for the purpose of calculating avoided energy rates shall be based on IRP expansion plans that take into account only known and quantifiable costs." Order Setting Parameters, Ordering Paragraph (OP) 8. Thus, for the purpose of calculating avoided energy costs, the generation expansion plans used in the production cost models must be based on IRP expansion plans that take into account only known and quantifiable costs. Because the Commission determined that the cost associated with carbon dioxide emission control is not known and quantifiable at this time, an IRP expansion plan that takes into account the cost associated with carbon dioxide emission control cannot be used.

As pointed out by the Public Staff and NCSEA, the generation expansion plans used by DEC and DEP in their avoided energy cost calculations are based on assumptions that include carbon dioxide emission control costs. Public Staff Initial Statement, p. 27; NCSEA Initial Comments, section II.A.a. DNCP used a generation expansion plan in which the capacity reserve margin was increased due to uncertainties related to carbon dioxide emission control requirements. Johnson Affidavit, paragraph 9.

Utilizing a generation expansion plan that takes into account costs associated with the control of carbon dioxide emissions, while at the same time excluding avoided carbon dioxide emissions control costs as an input into avoided energy costs, distorts the avoided energy cost calculations. For example, the inclusion of carbon dioxide emissions control costs in IRP modeling may result in the selection of new nuclear units as the least cost generation, as it did with DEC's base case in its 2014 IRP, and the low cost energy provided from the new nuclear units can then result in an underestimation of avoided fuel costs. Public Staff Initial Statement, p. 27. At the same time, DEC and DEP failed to include the costs associated with the control of carbon dioxide emissions control in the avoided energy cost calculation. Similarly, because DNCP included a larger capacity reserve margin in its generation expansion plan, it relied more on newly constructed, highly efficient combined cycle units and less on older generating units with higher operating costs when modeling production costs in this proceeding, which in turn, reduced costs associated with the marginal units, translating into a lower avoided energy cost. Johnson Affidavit, paragraph 10. Similar to DEC and DEP, DNCP did not include costs associated with the control of carbon dioxide emissions control in its avoided energy cost calculation. Thus, the use of generation plans that take into account carbon dioxide emissions control costs coupled with the failure to include such costs in the avoided energy calculation results in an understated avoided energy cost.

Because they failed to comply with the Commission's Order Setting Parameters on this issue and because the use of a generation expansion plan that takes into account costs associated with the control of carbon dioxide emissions—while at the same time excluding avoided carbon dioxide emissions control costs from the avoided energy cost calculation—distorts the avoided energy calculation, DEC, DEP and DNCP must recalculate their avoided energy costs using expansion plans that do not take into account carbon dioxide emissions control costs.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 6

As the Commission found in its Order Setting Parameters, "renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to purchase." Order Setting Parameters, p. 42. Noting that DEC and DEP have posited in separate proceedings that "a utility's fuel hedging programs to mitigate fuel price volatility can result in significant costs that are borne by ratepayers[,]" the Commission concluded:

> [T]hat there are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable

> generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation.

Order Setting Parameters, p. 42. In light of the foregoing, the Commission directed the Utilities "to calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates." Order Setting Parameters, OP 9.

The Public Staff took the position that the Utilities have not properly reflected the hedging value of renewables in their respective avoided cost rates. Public Staff Initial Comments, p. 35. The Public Staff explained that DEC and DEP utilized forward prices to determine their respective avoided energy costs; however, as addressed earlier in these comments, the Public Staff has concerns with DEC and DEP's fuel price forecasts. Public Staff Initial Comments, p. 35. In addition, the Public Staff explained that DNCP's avoided energy costs include the hedging fees that it expects to incur related to the purchase of natural gas; however, the Public Staff explained that these fees are transaction costs that DNCP will pay to purchase natural gas. Public Staff Initial Comments, p. 35.

Based on its concerns with the methods used by the Utilities, the Public Staff indicated that it "does not believe that the avoided energy costs of the utilities fully reflect the fuel price hedging benefits that result from the substitution of renewable generation for fossil-fueled generation." Public Staff Initial Comments, p. 35. Therefore, the Public Staff recommended that the Commission direct DEC, DEP, and DNCP to recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year that renewable generation helps the utility avoid fuel purchases associated with traditional generation.

The Public Staff performed its own evaluation of fuel price hedging benefits. Using the Black-Scholes Option Pricing Model, the Public Staff determined that a net option price, the price of a call option minus the price of a put option, for "at-the-money" Henry Hub natural gas options is approximately $.04 per dekatherm for the 12- and 24-month hedge terms used by the Utilities. Public Staff Initial Comments, p. 36. The Public Staff then converted the $.04 per dekatherm net option price to a hedge value of 0.028 cents per kWh. Public Staff Initial Comments, p. 36. The Public Staff recommended that the Commission direct DEC, DEP, and DNCP to recalculate hedging benefits using the Black-Scholes Option Pricing Model or a similar method that values the added fuel price stability gained through each year that renewable generation helps the utility avoid fuel purchases associated with traditional generation. Public Staff Initial Comments, p. 36.

SACE, like the Public Staff, took the position that hedge value should be accounted for in each year of a QF contract, regardless of the hedge horizon, as it is unreasonable to assume that the utility will not hedge beyond the first year of the QF contract. SACE Initial Comments, p. 6. DNCP agreed with this position. DNCP Reply Comments, p. 22.

NCSEA also expressed concern regarding the Utilities' efforts at including the hedging value of renewables in their respective avoided cost rates. With respect to DEC and DEP, NCSEA took the position that basing the hedge value on "ask" prices, rather than lower prices closer to the midpoint between "bid" and "ask" prices, does not quantify the benefit of avoiding future fuel price volatility, nor does it indicate what it would cost to hedge against this volatility. Johnson Affidavit, paragraphs 29-33. With respect to DNCP, NCSEA took the position that DNCP's approach of dividing avoided broker charges by the total annual non-nuclear energy supply does not accurately calculate the cost of fuel hedging on a per-MWh basis, nor does it accurately measure the fuel hedging benefit that is provided when non-nuclear generation is replaced by renewable QF generation. Johnson Affidavit, paragraphs 34-35. Taking the position that the DNCP approach does not provide an appropriate matching of the numerator and denominator, NCSEA affiant Johnson pointed out that the numerator is limited to the portion of DNCP's fuel costs which was hedged during 2012/13, whereas the denominator includes electricity generated using fuel that was not hedged. Johnson Affidavit, paragraphs 36. Johnson posited that to develop a meaningful ratio the numerator and denominator should be more consistent with each other, giving the example that if just 20% of DNCP's fuel purchases were hedged in 2012/13, then just 20% of its 2012/13 MWh should logically be used in the denominator. Johnson Affidavit, paragraphs 36.

Through data requests, NCSEA evaluated the method proposed by the Public Staff, as well as the calculation of the hedge value, and did not take issue with either in principle. However, NCSEA took issue with the "risk free interest rate" used by the Public Staff in calculating the hedge value. The Public Staff utilized the Black-Scholes options calculator to calculate the hedge value, which is available on-line. The calculator requires the input of an interest rate and instructs that an appropriate rate is a "risk free interest rate." Johnson Affidavit, paragraph 41. The Public Staff used 1% as the rate; NCSEA proposed that a rate of at least 3.10% be used in the calculation, which is consistent with the range of risk free interest rates used by the Utilities in developing cost of equity estimates in their respective most recent rate case proceedings. Johnson Affidavit, paragraphs 42-45. NCSEA noted that with an interest rate of 3.10%, using all other assumptions and inputs used by the Public Staff, the resulting hedge value is 0.09 cents per kWh. Johnson Affidavit, paragraphs 46-50. Thus, NCSEA recommended that the Commission direct the Utilities to recalculate the avoided energy component of avoided cost rates, using a hedge value of at least 0.09 cents per kWh in each year of the term of the QF power purchase agreement.

For the reasons raised by the Public Staff and by NCSEA, the Commission concludes that the Utilities have not properly reflected the hedging value of renewables in their respective avoided cost rates. For the purposes of this proceeding, the Commission concludes that the Black-Scholes Option Pricing Model endorsed by the Public Staff is a reasonable method for calculating hedge value and that the interest rate endorsed by NCSEA is appropriate and consistent with the range of risk free interest rates used by the Utilities in developing cost of equity estimates in their respective most recent rate case proceedings. Therefore the Commission concludes that, for the purposes of this proceeding, the Utilities should add to the energy credit 0.09 cents per kWh, for each year of the term of the QF power purchase agreement.

NCSEA noted that the calculation of the fuel price hedging benefit provided by QF generation is a topic being discussed across the country. NCSEA Reply Comments, section II.A.b. NCSEA pointed to recent work completed by Austin Energy in conjunction with Clean Power Research, a consulting firm that was retained by Duke Energy to collaborate on the Duke Energy Photovoltaic Integration Study: Carolinas Service Areas (commonly referred to in phase one of this proceeding as the "PNNL Study"), to develop a web-based tool that calculates fuel price hedge value of solar generation. NCSEA Reply Comments, section II.A.b. In light of the fact that methodologies related to fuel price hedge value provided by QF generation are likely to be increasingly discussed and analyzed across the country, the Commission is inclined to revisit this issue in a future proceeding, particularly if a national consensus on methodology emerges that differs from the methodology herein approved.

DISCUSSION AND CONCLUSIONS FOR FINDING NOS. 7 – 11

When utilizing the peaker methodology to calculate avoided costs, the calculation of avoided capacity cost relates largely to the installed cost of a natural gas fired CT. The electric utility's financial carrying cost for the CT, an estimate of fixed operating and maintenance costs, an adjustment for line losses, an estimate for working capital, and a performance adjustment factor are also used in calculating the avoided capacity cost. In the Order Setting Parameters, the Commission directed as follows:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data.

Order Setting Parameters, p. 48; see also Order Setting Parameters, OP 6. In calculating the installed cost of a CT, DEC and DEP used subscription-based data from the Electric Power Research Institute (EPRI) Technical Assistance Guide (TAG). In contrast, DNCP used the Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM (the Brattle Report), which is publicly available at no cost.

The Public Staff took the position that the Utilities should strive to utilize data from publicly available sources and provide clear justifications for any adjustments made to the publicly available data. Public Staff Reply Comments, p. 5. NCSEA took the position that none of the Utilities complied with this directive from the Commission. NCSEA Initial Comments, section II.B.a.

Ultimately, the objective of PURPA's full avoided cost rule is that Utilities' ratepayers be financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources. To ensure ratepayer indifference, the estimated avoided capacity costs must be reasonable and accurate.

Publicly Available Industry Source

Neither the Public Staff nor NCSEA took issue with the industry source used by DNCP. NCSEA noted that the Brattle Report is a publicly available industry source of the type contemplated by the Commission and provides a complete, robust estimate for the installed cost of a CT and that the Brattle Report provides a cost estimate that is geographically tailored for Dominion's North Carolina and Virginia Service territories. NCSEA Initial Comments, section II.B.a.1.

However, both the Public Staff and NCSEA took issue with the industry source used by DEC and DEP, expressing the concern that DEC's and DEP's use of the subscription-based EPRI data limits the public availability of the cost information and reduces the transparency of the avoided cost proceeding. Public Staff Reply Comments, pp 4-5; NCSEA Initial Comments, section II.B.a.2. In addition, NCSEA pointed out that:

> Even though the EPRI TAG is arguably an "industry source," it is not developed for general public distribution. In fact, the TAG is "available at no cost to funding members only," and while non-members have the option of purchasing the information, the asking price of $75,000 or more precludes this from being a practical option. Furthermore, the specific data relied upon by DEC and DEP was marked "CONFIDENTIAL" in their March 2015 Filings, which fundamentally contradicts the notion that this information be "publicly available." Under the circumstances, the EPRI TAG does not appear to qualify as a "publicly available industry source."
>
> In addition, the TAG does not provide a complete installed cost estimate of a CT, rather it provides only some of the components of the installed cost. For this reason, DEC and DEP contracted with engineering firm Burns & McDonnell (B&M) to obtain "generic unit cost estimates" so that they could add "costs for evaporative coolers and dual fuel capability to the EPRI project cost" as well as for

"transmission interconnection costs, gas supply interconnection costs and the addition of a gas metering and regulation (M&R) station." The B&M data were clearly not obtained from a "publicly available industry source," further casting doubt on the appropriateness of the data sources relied on by DEC and DEP. As well, it is worth noting that combining cost estimates from two different sources is not preferable, since this creates the potential for inconsistencies, double counting of items, omission of items, or the overstatement or understatement of costs due to differences in estimating methods or sources.

NCSEA Initial Comments, section II.B.a.2; Johnson Affidavit, paragraph 59 (illustrating errors that may happen when data points from different sources are combined).

Similarly, SACE noted concern with the fact that much of the data relied upon by DEC and DEP was marked confidential. SACE Initial Comments, section B.2.

The Commission is concerned with the use of a subscription-based industry source by DEC and DEP, particularly in light of the fact that the Brattle Report, which provides a robust and well-vetted cost estimate, is publicly available. Going forward, the Commission directs DEC and DEP to use the Brattle Report, or an analogous publicly available industry source, that is, in fact publicly available.

<u>Tailoring of Data from Publicly Available Industry Source</u>

In directing the Utilities to use data from publicly available industry sources when calculating the installed cost of the "hypothetical CT," the Commission provided the following guidance:

> Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Order Setting Parameters, p. 48; see also Order Setting Parameters, OP 6. In the first phase of this proceeding, the Commission rejected DNCP's argument that the cost of land should not be included in the installed cost of the CT when the next CT built by DNCP will not be located on a greenfield site. The Commission explained that "the peaker method uses a hypothetical CT as a proxy for pure capacity and is designed to approximate the cost of a new baseload plant." Order Setting Parameters, p. 48. Thus, because the cost of installing a <u>hypothetical CT</u> is the underlying basis for the peaker method's valuation of capacity, any tailoring that is inconsistent with the premise of a "hypothetical CT" is inappropriate.

Moreover, the Commission is concerned that combining data points from different sources generated at different points in time has the potential to produce distorted results. Specifically, NCSEA affiant Johnson noted, with respect to a tailoring modification proposed by DEC and DEP, that:

> [The] modification proposed by DEC and DEP has the potential to introduce errors. Any potential improvement in accuracy that might potentially be achieved by relying on more recent MW capacity data is outweighed by the potential for distortions being introduced by mixing data from different sources, developed at different times, using different assumptions. For example, a larger capacity generator might require the installation of larger, more costly gas or electrical interconnection facilities than the ones that were assumed in the 2014 B&M data relied upon by DEC and DEP. Similarly, EPRI might have published larger cost estimates for certain facilities if it had assumed these facilities would be used with larger turbines, consistent with the MW capacity assumptions made by DEC and DEP.

Johnson Affidavit, paragraph 59. Thus, the Commission notes that the combining of data points from different sources is not likely to produce an accurate cost estimate that, ultimately, meets the objective of ratepayer indifference.

The Commission made clear in its Order Setting Parameters that the Utilities are authorized to tailor the cost estimates provided in publicly available industry sources, but the Commission was also clear that any such tailoring must be "clearly needed" to adapt the information provided in the publicly available industry sources to the Carolinas and Virginia. Thus, the Commission did not provide the Utilities with unfettered discretion to assemble their own cost estimates using bits and pieces of information taken from various sources. Indeed, this sort of unfettered discretion would defeat the purpose of requiring use of a cost estimate from a publicly available industry source. Each of the Utilities tailored the data taken from the industry sources. As set forth below, the Commission is not persuaded that each of the following elements of the Utilities' "tailoring" was clearly needed to adapt the data to the Carolinas and Virginia.

<u>Siemens CT</u>

In calculating its installed cost estimate, DNCP substituted a lower cost Siemens CT in place of the GE 7FA CT used in the Brattle Report.

NCSEA took the position that despite the fact that the Brattle Report provides an installed CT cost estimate that is geographically tailored for DNCP's North Carolina and Virginia service territories, DNCP made more than a dozen different adjustments and modifications, each of which reduced DNCP's cost per kW below the estimate provided in the Brattle Report. NCSEA explained that the most significant of DNCP's adjustments involves the equipment cost estimate for the CT. Specifically, NCSEA pointed out that:

> Notwithstanding the fact that the Brattle Report estimates the installed cost of a CT using the cost of GE 7FA model CT, which is representative of DNCP's generating fleet, DNCP removed this cost from its estimate and instead relied on the 2013 Gas Turbine World Handbook ("GTW Handbook") equipment cost estimate for the SGT6-5000F model CT manufactured by Siemens, which is significantly lower than the GE model CT. This adjustment was made in spite of the fact that DNCP has not installed any Siemens SGT6-5000F CTs or similar Siemens models and in spite of the fact that it does have GE model CTs in its generating fleet. In its order, the Commission directed the Utilities to tailor cost estimates taken from publicly available industry sources only to the extent necessary to adapt such information to the Carolinas and Virginia. DNCP's tailoring of the Brattle Report estimate to include the cost associated with the Siemens SGT6-5000F CT does not comply with this directive. To the contrary, the adjustment moves away from a CT model that has been widely installed throughout Virginia and the Carolinas to a CT model that is not even used by DNCP.

NCSEA Initial Comments, section II.B.a.2.

The Public Staff also expressed concern with the adjustment, noting that DNCP made the substitution "despite the fact that the authors of the 2011 and 2014 Brattle Reports surveyed the CTs built around the country and concluded that the GE 7FA model is the predominant CT model built and best turbine on which to base its cost of new entry." Public Staff Reply Comments, p. 6. The Public Staff also pointed out that the report concludes that the " ' GE 7FA turbine [is] a reasonable choice for the PJM CT reference technology as it is the turbine model that has been built in most of PJM since 2008 and has a lower turbine cost per-kilowatt than the aeroderivative models.' " Public Staff Reply Comments, p. 6.

DNCP defended the substitution of the lower cost Siemens CT by pointing to its selection of the same Siemens CT as the least cost CT option modeled in its IRP. DNCP Reply Comments, pp 5-12. However, the Commission is not persuaded by DNCP's justification for the substitution of the lower cost Siemens CT. The Commission does find persuasive the facts that DNCP has not installed any Siemens SGT6-5000F CTs or similar Siemens models and that it does have GE model CTs in its generating fleet. The Commission notes, as pointed out by DNCP, that the Siemens CT has seen the largest reduction in price per kW over the past five years, resulting in its being the lowest cost CT of those evaluated by the company. DNCP Reply Comments, p. 9. However, DNCP acknowledged that the company cannot guarantee that when the time comes to install a CT, the company will actually use a Siemens CT. DNCP Reply Comments, p. 12. Finally, the Commission finds particularly persuasive the fact, which is acknowledged by

DNCP, that the GE 7FA CT is the reference resource in the PJM OATT. See DNCP Reply Comments, p. 6.

Because the Commission is not persuaded that the substitution of the lower cost Siemens CT is clearly needed to adapt the Brattle Report's installed cost estimate to the Carolinas and Virginia, the Commission directs DNCP to recalculate its avoided capacity cost using the Brattle Report's cost estimate without the substitution.

<u>Economies of Scale and Scope</u>

In the Order Setting Parameters, the Commission provided that the Utilities, when calculating the installed cost of a CT, may include economies of scale for up to four CTs constructed on the same site, however the Commission made clear that the Utilities "shall not include any economies of scope associated with the construction of more than one CT at the same time." Order Setting Parameters, OP 7.

NCSEA argued that the Utilities inappropriately included economies of scope when calculating the installed cost of a CT. NCSEA Initial Comments, section II.B.b. Specifically, NCSEA argued that because the Brattle Report assumed a 2-unit at which both turbines were assumed to be constructed at the same time, the cost estimates in the Brattle Study also include cost savings from economies of scale <u>and scope</u>. NCSEA argued that despite making numerous other adjustments to the data included in the Brattle Report, DNCP did not propose any adjustments to the data to remove the impact of these economies of scope. NCSEA Initial Comments, section II.B.b.1; Johnson Affidavit, paragraphs 61-62.

NCSEA affiant Johnson pointed out that although DNCP did not propose any upward adjustments to remove economies of scope from the Brattle data, DNCP did propose downward adjustments to reflect additional economies of scale, corresponding to a 4-unit site rather than a 2-unit site, in two cost categories: electrical interconnection and gas interconnection. Johnson Affidavit, paragraph 62. Johnson asserts that, in doing so, DNCP cut the Brattle cost estimates in half, which substantially overstates the actual impact of economies of scale and is particularly excessive in this context, where additional units are being constructed sequentially rather than simultaneously. Johnson Affidavit, paragraph 62.

NCSEA argued that although DEC and DEP recognized the distinction between economies of scale and scope that was drawn by the Commission, they had elected to deviate from the Commission's order simply because they assert they had difficulty complying with the corresponding requirements of the Commission's order. NCSEA Initial Comments, section II.B.b.2. Specifically, NCSEA pointed out that DEC and DEP based their calculations on the assumption they would simultaneously build four units at two different sites, thereby including both economies of scale and scope. Johnson Affidavit, paragraph 63. DEC and

DEP used EPRI data, which reflects the combined impact of both economies of scale and scope for projects of various sizes, to calculate the adjustments made. NCSEA affiant Johnson took issue with DEC's and DEP's decision to use the EPRI data for 2-unit sites because they could have instead started with the 1-unit data and then made reasonable adjustments for economies of scale in the appropriate categories of land, site preparation work, roads, buildings and structures, as well as general plant facilities. In addition, NCSEA affiant Johnson explained that adjustments for economies of scale must be calculated net of additional carrying costs that would be incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when these are needed for the additional units Johnson Affidavit, paragraphs 67-69.

SACE similarly commented that DEC and DEP erroneously included economies of scope. SACE Initial Comments, p.8.

In its reply comments, Public Staff agreed with NCSEA and SACE that economies of scope were not properly excluded by the Utilities from the installed cost of a CT and recommended that the Commission direct the Utilities to recalculate their avoided capacity costs to ensure that all economies of scope are excluded. Public Staff Reply Comments, pp 6-7.

While the Utilities have clearly captured savings due to economies of scale, they have clearly failed to exclude savings due to economies of scope, despite the direction provided in the Order Setting Parameters. Nor is the Commission convinced that the Utilities are incapable of complying with the Order using reasonable efforts. Accordingly, the Utilities are directed to recalculate their avoided capacity costs to ensure that all economies of scope are excluded and that any carrying costs that the utility might incur are netted out of the economies of scale savings.

<u>Contingency Factor</u>

In the Order Setting Parameters, the Commission directed the Utilities to use a reasonable contingency factor for a hypothetical plant in relatively early stages of planning. Order Setting Parameters, OP 7.

A contingency factor covers unforeseen costs that are likely to arise during construction. As explained in the Brattle Report, in the context of engineering, procurement and construction costs (EPC), "contingency covers undefined variables in both scope definition and pricing that are encountered during project implementation." Brattle Report, p. 18. In the context of owner's costs, the Brattle Report explains that "contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, etc." Brattle Report, p. 23. The Brattle Report assumes an EPC contingency of 10% and an owner's contingency of 9%. Brattle Report, p. 23.

Black & Veatch, an international Engineering, Construction Management and Design-Build firm, has explained that:

> There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site-specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site-specific differences.

Cost Report: Cost and Performance Data for Power Generation Technologies, prepared by Black & Veatch, prepared for National Renewable Energy Laboratory, February 2012, p.8, available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

Finally, in providing a cost estimate for a natural gas fired CT, the EIA includes a 10% contingency on EPC costs, as well as an additional 20% allowance for owner's costs and contingency, excluding financing. Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, prepared by United States Energy Information Administration, April 2013, Sections 8 and 9, available at: http://www.eia.gov/forecasts/capitalcost/.

The Commission concludes that the reasonableness of a particular contingency factor varies, depending upon the specific context in which the factor will be used. A 5% to 10% contingency factor might be adequate for internal purposes at the late stages of the planning process, but that same 5% to 10% contingency factor would not be adequate, even for internal purposes, during the earlier stages of the planning process. In the context of this proceeding, where the goal is to compensate for the risks borne by ratepayers throughout the entire planning, design and construction process, a higher contingency is necessary, consistent with the Commission's directive that the contingency factor reflect "a hypothetical plant in relatively early stages of planning."

DNCP utilized the contingency factor provided in the Brattle Report and did not adjust this data point. NCSEA and the Public Staff argued that should the Commission deem DNCP's substitution of the lower cost Siemens CT appropriate, then the Commission must direct DNCP to utilize a higher contingency factor to reflect DNCP's lack of experience with the Siemens unit and the corresponding lack of ability to forecast construction and other risks with accuracy. NCSEA Initial Comments, section II.B.c.1; Public Staff Reply Comments, p. 7. However, as discussed above, the Commission deems DNCP's substitution of the lower cost Siemens CT to be inappropriate. Because DNCP will recalculate its avoided capacity cost using the GE 7FA CT included in the Brattle Report, it is appropriate for DNCP also to use the contingency factor included in the Brattle Report.

DEC and DEP substituted a lower contingency factor in place of the contingency factor used in the EPRI data. DEC and DEP defend this adjustment on the basis of past experience in constructing and operating CTs in the Carolinas. DEC/DEP Reply Comments, pp 21-24. NCSEA points out that in the first phase of this proceeding, DEC and DEP witness Snider testified that the equipment and construction costs estimated for the CT should represent an expected construction cost with neither a best case nor worst case contingency adder included and that a 5% contingency adder results in a reasonable expected construction cost. NCSEA Initial Comments, section II.B.c.2. NCSEA points out that instead of specifically accepting Snider's recommendation, the Commission directed the Utilities to include a contingency factor that is consistent with a "hypothetical plant in relatively early stages of planning," suggesting that Snider's recommendation, which is the same contingency adder used by DEC and DEP in this proceeding, was inadequate for purposes of this proceeding. NCSEA Initial Comments, section II.B.c.2.

As it did in its Order Setting Parameters, the Commission again rejects the DEP/DEC position, as it is not consistent with a "hypothetical plant in relatively early stages of planning." Accordingly, the Commission directs DEC and DEP to recalculate their installed cost estimates using the contingency factor set forth in the EPRI data that they selected.

<u>Useful Life</u>

In the Order Setting Parameters, the Commission specified that "a reasonable estimate of useful life of a CT" should be used "in the calculation of the installed cost of a CT." The carrying cost of the CT is the second largest component, behind the installed cost of the CT, in the avoided capacity cost calculation. The carrying cost calculation generally involves the application of factors such as the cost of capital, property and income tax rates, deferred taxes, insurance rates, and the projected inflation rate over the life of the CT. Therefore, the assumed useful life influences the avoided capacity cost, such that the longer the assumed useful life, the lower the carrying cost and, therefore, the lower the avoided capacity cost.

The industry sources used by the Utilities for the installed cost of the CT include information about the useful life of a newly constructed CT. However, the Utilities assumed longer useful lives in their avoided capacity cost calculations, which, again, has the effect of decreasing the avoided capacity cost estimates.

In its initial comments, NCSEA took the position that the Utilities should use the useful life assumptions included in the industry sources on which they relied due to the absence of detailed studies supporting longer useful lives. NCSEA Initial Comments, section II.B.d; Johnson Affidavit, paragraph 78.

DEC and DEP took the position that the useful life assumption used by the utilities in calculating avoided capacity cost is supported by depreciation studies and operational experience. DEC/DEP Reply Comments, pp 25-27.

DNCP took the position that the 36-year useful life assumption used by the utility is reasonable as it is supported by an asset depreciation study conducted by the utility and filed with the Commission in 2013. DNCP Reply Comments, p. 18. DNCP's depreciation study indicates that:

> [L]ife spans of 35 to 40 years were estimated for the majority of combustion turbines. These life span estimates are typical for combustion turbines which are used primarily as peaking units. . . .

The Commission notes that DNCP's depreciation study analyzes DNCP's generating assets and that, as pointed out by the Public Staff and NCSEA, DNCP's CT fleet consists primarily of GE units, not Siemens units. As the Commission has rejected DNCP's substitution of the Siemens CT, the Commission determines that it is reasonable for DNCP to use a 36-year useful life in conjunction with the GE CT when calculating its avoided capacity cost because the assumption is supported by DNCP's detailed depreciation study of DNCP's generating assets, filed for public inspection with the Commission in Docket N. E-22, Sub 493, that indicates that such useful life is "typical for combustion turbines which are used primarily as peaking units" and, therefore, consistent with the premise of a "hypothetical CT." However, with respect to DEC and DEP, although useful life assumptions used by the utilities may be supported by depreciation studies, such studies are not on file for public inspection and may not reflect useful lives "typical for combustion turbines which are used primarily as peaking units." Because such an adjustment would be inconsistent with the premise of the "hypothetical CT", it is not appropriate for DEC and DEP to adjust the useful life assumption in the industry source on which they relied.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 12

DEC, DEP and DNCP have proposed changes to seasonal weighting of the capacity rates.

The Public Staff pointed out that DEC and DEP have decreased the allocation for their summer (on-peak) months and increased the allocation for their non-summer (off-peak) months for both Option A and Option B avoided capacity rates, based on the utilities' historical CT production data. Additionally, the Public

Staff pointed out that DNCP has applied a similar allocation, also based on the utility's historical CT production data. Although the Public Staff did not appear to take issue with the weightings used, the Public Staff indicated that "continued use of a seasonal allocation of avoided capacity costs in the manner proposed by the utilities may need further review" and recommended that the Utilities provide similar CT production data in the next proceeding to determine whether the allocation remains reasonable. Public Staff's Initial Statement, p. 43.

DEC and DEP justify the proposed changes to seasonal weighting as part of their efforts to adopt each other's best practices, as they have determined that "the continuation of differing legacy allocation approaches for similar seasonal differences results in an unjustifiable difference in price signals between the two operating companies for QFs doing business in North Carolina." DEC and DEP explained that, in this proceeding, consistency in methodology leads to consistency in seasonal allocation, which may not always be the case. DEC and DEP analyzed CT production data to determine the appropriate seasonal allocation. DEC/DEP Reply Comments, pp 27-29.

DNCP did not provide a justification for this change; rather, DNCP agreed with the Public Staff's recommendation that the Utilities be directed to provide CT production data in the next proceeding to determine whether the allocation is reasonable. DNCP Reply Comments, p. 19.

In its initial comments, NCSEA pointed out that in the 2012 Proceeding, the Commission directed the Utilities to include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC at that time, in light of the settlement entered into between DEC, DEP and the Public Staff. In addition, NCSEA pointed out that with respect to DEP, the Commission found as follows:

> Subject to Commission approval, DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's. Following the completion of DEP's current review of its time-of-use rates, DEP should meet with the Public Staff to discuss those results before DEP proposes any changes to its Option B. In the event that DEP proposes a change to its Option B that increases the number of on-peak hours, the burden should be on DEP to show that the change is consistent with the goal of aligning the on-peak hours with the periods when DEP's customer demands and the value of capacity are the highest.

NCSEA Initial Comments, section II.C.a.

NCSEA pointed out that DEP did not meet with the Public Staff to discuss these changes prior to proposing them, and the fact that DEP's Time of Use Rate Study was not filed in Docket No. E-2, Sub 1023, until May 28, 2015 supports this position.

NCSEA also pointed out that during the first phase of this proceeding, after considerable discussion and presentation of evidence by all parties on the issue of adjusting the hours offered under Option B to better reflect the Utilities' needs, the Commission declined the parties' various requests to modify Option B, ultimately concluding that DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with the avoided capacity rates in Option B calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP and the Public Staff. NCSEA Initial Comments, section II.C.a.

In its reply comments, NCSEA disagreed with the Public Staff's acceptance, even if only for this biennium, of the changed seasonal weightings and urged the Commission to reject the change in allocation by the Utilities for the reasons pointed out in NCSEA's Initial Comments. NCSEA Reply Comments, section II.C.a. In addition, NCSEA took issue with seasonal allocation based on CT production, arguing that it is inconsistent with the peaker method. NCSEA noted that while a CT has long been used as a proxy for peaking capacity in North Carolina, the theory underlying the peaker method as recognized by the Commission is that the capacity cost of the peaker plus the marginal system running costs equal the cost of any generating plant, including a baseload plant. Further, NCSEA argued that the strength of the peaker method is that, in theory at least, the marginal capacity costs of all of a utility's resource investments are expected to equal one another in equilibrium, and, consequently, the quantitative result is not biased by the choice of one particular technology over another. NCSEA Reply Comments, section II.C.a.

In light of the foregoing, the Commission is not willing to consider modifications to seasonal allocation and instead defers consideration of this issue until a future proceeding when changes can be evaluated in a comprehensive manner to better tailor rates, and therefore align QF generation, to the Utilities' system needs.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 13

Limitations on Assignment Rights

DNCP's PPA provides that a QF may assign its rights under the DNCP PPA only with the prior written consent of DNCP. DNCP "may withhold such consent if it determines, in its sole discretion, that such assignment would not be in the best interests of [DNCP] or its customers."

NCSEA took the position that providing DNCP with "sole discretion" to reject an assignment for any reason is commercially unreasonable and problematic for NCSEA's business members. Further, NCSEA noted that the ability to assign a contract under reasonable conditions is essential to the commercial viability of renewable generation projects and, therefore, is necessary to encourage QF development. NCSEA recommended that this section should be amended to require that DNCP not unreasonably withhold consent to proposed assignment. NCSEA also took issue with the proposed increase in fee from $10,000 to $12,000 and argued that the increase is unjustified.

The Public Staff noted that in order to encourage QF development in compliance with PURPA, the Commission has included standard rates, terms, and conditions in its biennial avoided cost proceedings since Docket No. E-100, Sub 41A, to reduce the transaction costs for smaller project developers who may not have the resources or expertise to negotiate with a utility. The Public Staff noted that DNCP's proposed assignment provisions could constitute an unreasonable burden on QF development and should be revised accordingly.

In its reply comments, DNCP agreed to revise the provision to reflect that it will not unreasonably withhold consent to assignment, provided the assignment does not requirement amendment to any provisions other than notice provisions. DNCP Reply Comments, section II.D.

The Commission agrees with the concerns of NCSEA and the Public Staff and directs DNCP to revise the provision as indicated in DNCP's reply comments. In addition, the Commission rejects DNCP's increase in assignment fee.

<u>Overreaching Termination Right for Failure to Commence Construction</u>

The DNCP PPA gives DNCP the right to terminate—with no opportunity to cure—if a QF does not commence construction by a date certain.

NCSEA commented that although the DNCP PPA does not specify what this date is based on, DNCP has stated in (in response to data requests from NCSEA) that "[t]he date is based on the expected construction schedule for the Facility after consultation between Company and the Operator."

While not entirely clear, DNCP's response suggests that the date will be negotiated between the utility and QF. One of the primary purposes of a standard contract is to avoid the negotiation process. This is especially important with regard to a term such as this one, where failure to achieve the date could result in termination of the agreement. Furthermore, to the extent a QF's financing, and therefore ability to commence construction, is dependent on the receipt of an interconnection agreement, the QF's ability to commence construction as of a date certain is not entirely within its control.

In its reply comments, DNCP proposed alternative language that would require the QF to commence construction the later of 14 months from the effective date of the PPA or 30 days after the tender of an interconnection agreement. DNCP Reply Comments, section D.3.b. and c.

DNCP's proposed alternative is inconsistent with previous decisions of this Commission which give a QF 30 months from a final order approving rates to achieve commercial operation. Accordingly, the Commission directs DNCP to revise the DNCP PPA to make clear that the QF specifies the date on which construction is to have commenced, and has a 30-day opportunity to cure.

Use of Unclear Terminology

NCSEA noted that the terms "net capacity" and "net electrical capacity" are used throughout the DNCP PPA and the DNCP Rate Schedule and are not defined in any of the various documents. NCSEA commented that according to DNCP's response to a data request propounded by NCSEA, these terms mean the same thing.

In its reply comments, DNCP commented that it would revise is standard offer documents so that only the term "net capacity" is used and provided that the definition of net capacity is: "the maximum net electrical output of the Facility measured in kW alternative current, determined in accordance with Section 7 of FERC Form 556."

Therefore, the Commission directs DNCP to revise its standard offer documents accordingly.

Increase in Availability limitation to One Mile

DNCP proposed to amend the DNCP Rate Schedule to provide that a QF owned by a developer or affiliate who sells or will sell power to DNCP from another QF located within one mile is not eligible for the standard rates unless the combined capacity is equal to or less than five megawatts.

The Commission notes that DNCP previously had a similar provision in its rate schedule but the distance between QFs was limited to one-half mile.

NCSEA stated that DNCP provided no justification for the increase from one-half mile to one mile. NCSEA noted that DEC has historically included a similar one-half mile availability limitation, and in this proceeding DEP has also proposed to include the same limitation as DEC. NCSEA recommended that the Commission approve DEP's one-half mile proposal and limit DNCP's proposal to one-half mile.

The Public Staff agreed that in the interests of fairness and clarity, the Commission should adopt a consistent availability limitation for each of the Utilities. As such, the Public Staff recommended that the Commission approve the availability limitations for each utility limited to one-half mile, while maintaining the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms so long as the combined capacity of those facilities does not exceed five megawatts.

SACE also took exception to DNCP's proposed proximity limitation, noting that the restriction should only apply when the two proposed facilities under common ownership use the same energy resource. SACE also noted that it should be made clear that the distance between facilities is measured from the electrical generating equipment of a facility for purposes of making the one-mile determination. The Public Staff noted that these requirements are analogous to the size and location criteria for QFs adopted by the FERC, which provide in part:

> (a) Size of the facility—(1) Maximum size. Except as provided in paragraph (a)(4) of this section, the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities *that use the same energy resource*, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.
>
> (2) Method of calculation. (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.
>
> (ii) *For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility*.[2]

The Public Staff agreed that the one-half mile restriction should only apply to facilities that use the same energy resource, and that the Utilities should include language stating that the distance between facilities would be measured from the electrical generating equipment of a facility.

The Commission is persuaded that fairness, clarity and ease of administration dictate a uniform approach across all Utilities and, therefore, rejects DNCP's proposal to increase the limitation to one mile. In addition, the Commission adopt the recommendations of SACE to require the Utilities to make

[2] 18 CFR § 292.204: Criteria for Qualifying Small Power Production Facilities (emphasis added).

clear that the limitation applies to facilities that use the same energy resource and that the distance between facilities would be measured from the electrical generating equipment of a facility.

Elimination of Site Specific Line Loss Allowance

DNCP proposed to continue using a 3% line loss allowance for all QF projects but to eliminate the QF's option to request a site-specific line loss allowance that is based on a study conducted at the QF's cost.

In its reply comments, DNCP justified the proposal on the Commission's desire to keep standard contracts free of negotiation. DNCP Reply Comments, section D.5. DNCP indicated that, if the Commission were inclined to direct DNCP to maintain the option of a site specific allowance, then the QF should be solely responsible for the cost of the study and bound by its results.

The Commission concludes that DNCP would suffer no prejudice from retaining the option and notes that, the currently-approved provision requires the QF to bear the cost of the line loss study. The Commission also concludes that it is reasonable for a QF to be bound by the result of a study, should it elect this option. Therefore, the Commission rejects DNCP's proposal to eliminate the option to request a site-specific line loss allowance that is based on a study conducted at the QF's cost.

Elimination of Opportunities to Cure and Increased Termination Rights

DNCP proposed several revisions to the DNCP PPA related to DNCP's right to terminate based on events of default by the QF. Specifically, DNCP clarifies which defaults by the QF are subject to the QF's opportunity to cure and which defaults give DNCP the right to terminate without any opportunity to cure.

NCSEA commented that while NCSEA generally supports additional clarity regarding QFs' obligations and the consequences of failing to fulfill them, it objects to the inclusion of certain events of default in Article 7(a) of DNCP's Standard Contract, which governs defaults with no cure period. Specifically, NCSEA took issue with the following provisions:

i. Article 7(a)(ii): Failure to provide two consecutive status reports in accordance with Article 6. Article 6 of DNCP's Standard Contract requires the QF to submit quarterly construction status reports (by specified dates) prior to achieving commercial operation. DNCP proposed to allow termination with no opportunity to cure in the event of a QF's failure to provide consecutive status reports. NCSEA commented that this was a draconian measure for an administrative default. In its reply comments, DNCP proposes to allow a 30-day cure period for failure to provide a report. DNCP Reply Comments, section II.D.3.a.

The Commission directs DNCP to revise the proposal accordingly.

ii. Article 7(a)(v): Failure to maintain an Interconnection Agreement in full force and effect unless such failure is due to DNCP's breach of the Interconnection Agreement. NCSEA noted three problems with classifying this situation as an uncurable default. First, the phrase "in full force and effect" is ambiguous and undefined. Second, the proposed language fails to specify that the right of termination does not exist where a QF has an interconnection agreement with a party other than DNCP (i.e., with PJM Interconnection, LLC) and the interconnection agreement is terminated or suspended based on that party's default. And third, there is no reason why this event of default should be considered uncurable, if the QF's interconnection agreement can be brought back into "full force and effect" within a reasonable cure period. In its reply comments, DNCP proposed to make failure to maintain an interconnection agreement a curable default and to modify the description of default to make clear that failure is due to party other than the QF. DNCP Reply Comments, section II.D.3.d.

The Commission directs DNCP to revise the proposal accordingly, explicitly providing a 30-day cure period.

iii. Article 7(a)(vii): Granting of a PURPA 210(m) petition. DNCP proposed to include a provision that grants the utility a right to terminate a contract when the FERC grants a petition by the utility under PURPA Section 210(m). The DNCP PPA notes that the provision would be included in the contract if the Company has a PURPA Section 210(m) application pending before the FERC on the effective date of the PPA.

The Public Staff noted that at the time of the March 2, 2015, filing, DNCP did have a PURPA Section 210(m) application pending before the FERC. However, the FERC declined to grant that petition. As such, the Public Staff believes that inclusion of this provision seems unnecessary at this time, and recommends that the Commission direct DNCP to remove the provision from its standard contract. Public Staff Reply Comments, p. 10.

NCSEA commented that the provision proposed by DNCP should not be characterized as an event of default by the QF, and to the extent the provision is permissible, it should not be included in Article 7(a), which is titled "Defaults with No Cure Period." NCSEA Initial Comments, section III.A.f. The Public Staff agreed that the placement of this term is inappropriate and that to the extent the clause remains in DNCP's Standard Contract, it should be included as a stand-alone clause.

The Commission agrees with the Public Staff that this provision is unnecessary at this time and must be struck.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 14

30-month Deadline for Achieving Commercial Operation

NCSEA commented that DEC and DEP neglected to include in the DEC/DEP PPA and in the rate schedules the qualifying language approved by the Commission in its 2012 Order related to the 30-month deadline for achieving commercial operation, which provided that a “QF should be allowed additional time if the project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.” NCSEA Initial Comments, section III.B.a.

The Public Staff agreed that DEC and DEP should amend their contracts to provide that the utility may terminate a contract after 30 months if the QF has failed to achieve commercial operation at any level by that date, provided that the QF should be allowed additional time if the project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner. Public Staff Reply Comments, pp 14-15.

DEC and DEP commented that the companies have resolved the issue by agreeing to include the qualifying language in the PPA and rate schedules. DEC/DEP Reply Comments, p. 42. DEC and DEP set forth the specific revisions agreed upon in a letter filed by DEC/DEP in this docket on September 17, 2017 (the “Settlement Letter”). Therefore, the Commission directs DEC and DEP to revise the contracts in accordance with the Settlement Letter.

Commencement of Term

NCSEA commented that the DEC/DEP PPA provides that the term of the contract begins on the earlier of a date certain (as specified in the contract) or the date the utility is first ready to accept electricity from the seller. NCSEA further noted that DEC’s contract historically has commenced on the initial delivery date, and that DNCP’s standard contract provides that the term runs from the commercial operation date of the facility. NCSEA Initial Comments, section II.B.c.

The Public Staff noted that the proposed provision in the DEC/DEP PPA contract generally adopts the approach used by DEP in the contracts approved in the Sub 136 proceeding and in prior years. The Public Staff did not take issue with this provision but recommended that, in order to provide assurance that the consent to extend this date will not be unreasonably withheld, the Commission direct DEC and DEP to amend their consent provisions to provide that consent to an extension of this initial delivery date shall not be withheld if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner. Public Staff Reply Comments, p. 15.

DEC and DEP commented that NCSEA and the companies had resolved the concern noted by NCSEA and indicated the agreed upon revisions. DEC/DEP Reply Comments, pp 42-43. DEC and DEP set forth the specific revisions agreed upon in the Settlement Letter. Therefore, the Commission directs DEC and DEP to revise the contracts in accordance with the Settlement Letter.

<u>Reduction in Contract Energy Charge and Reduction in Contract Capacity Charge</u>

In their Terms and Conditions, DEC and DEP have proposed a provision that would allow the utility to apply to the Commission on a case-by-case basis for approval to impose a charge in the event the QF's average energy generated or capacity falls significantly below the contract energy and capacity levels. DEC and DEP justified the provision as follows:

> Long-term levelized rate QF contracts create a tension between encouraging QF development, on the one hand, and the risk of overpayments to QFs, on the other. Long-term levelized rates tend to overpay the QF in early years and underpay the QF in later years. Consequently, a QF's economic incentive to incur the costs of operating and maintaining the facility diminishes, and could even disappear over the life of a long-term levelized contract.

DEC/DEP Reply Comments, pp 33. DEC and DEP argue that the charge is a "mechanism to adjust the contract to restore the expected balance of the economic benefits to both parties in the event the QF's performance falls materially short of its contractual obligation." DEC/DEP Reply Comments, pp 33-34.

NCSEA took issue with the proposed Reduction in Contract Energy and Reduction in Contract Capacity Charge provisions. NCSEA Initial Comments, Section III.B.d. NCSEA noted that DEP had previously included a similar provision in its standard contract, but the Commission in the 2012 Proceeding directed DEP to strike the provision, finding it inconsistent with previous rulings of the Commission. The Commission, however, indicated that DEP could "propose a provision that allows it to take action if the harm it alleges the penalty is designed to fix occurs (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval."

The Public Staff pointed to its comments made in the 2012 Proceeding in which it noted that the Commission previously held, in Docket No. E-100, Sub 59, that a utility could require a QF to state the amount of capacity and energy it intends to provide but could not use the stated amount to penalize the QF, particularly a QF that cannot control its fuel, such as run-of-the-river hydro, solar, or wind, absent an explicit order from the Commission. The Public Staff also pointed out that QFs, under the standard contracts, are not paid unless they are generating, and, therefore, a penalty is unwarranted.

The Public Staff took the position that the proposed provision does not address the concern of underperformance in later years. Consequently, the Public Staff recommended that the Commission direct DEC and DEP to refile a proposal that more directly addresses underproduction in later years of a levelized contract that results in overpayment during the early years and, until such time as the proposal is approved by the Commission, remove the provision from their Terms and Conditions.

In the first phase of this proceeding, the Commission received evidence on the issue of the Utilities' exposure to overpayments in the context of long-term, levelized rates. In fact, the Commission weighed evidence presented by: (i) the Utilities, related to "degraded performance, financial failure, weather, fuel supply, or other risks that could lead to overpayment;" (ii) the Public Staff, related to the fact that facilities with predictable capital costs and no fuel do not present these risks; and (iii) NCSEA, related to the facts that facilities are typically financed over the term of the power purchase agreement and that default under the financing arrangements could result in such things as the change of control rights of equity investors being triggered and of the owners being required to pay liquidated damages under loan documents, both of which militate against nonperformance.

Ultimately, the Commission concluded as follows:

> [E]xperience has shown that there is a limited risk of nonperformance. In addition, the testimony offered by the solar developers as to the restrictions and limitations in their financing offers a measure of assurance that a solar QF's output will not decrease over the long term. The fact that solar QFs do not have to rely on fuel contracts, the viability of a steam host or some other external factor also weighs in favor of allowing levelized rates to continue. A solar generating facility has fairly predictable capital costs, production profiles, and other characteristics, such as zero fuel costs, that allay many of the concerns raised by DNCP witness Williams.

Order Setting Parameter, pp 20-21. DEC and DEP point to a presentation made by Advanced Energy to support their assertions regarding nonperformance. The presentation identifies several issues related to the interconnection of customer-owned generation. The Commission is concerned about making generalizations based on anecdotal information related to fifteen customer-owned sites and remains persuaded that the risk of nonperformance is limited.

Similar to the Commission determination in the 2012 Proceeding, the Commission concludes that the DEC/DEP proposal is inconsistent with the stated purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts, as they may apply in both early (after two years) and later years of a contract. In addition, the Commission is not convinced that nonperformance in later years of a contract is a risk. For these reasons, the Commission rejects the DEC/DEP proposal.

Notwithstanding the foregoing, as mentioned above, the 2012 Order directed DEP to strike the provision but allowed DEP to propose an alternate provision that allows it to take action if the harm it alleges the penalty is designed to fix occurs (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval. The following language is approved by this Commission as such an alternate provision:

> CONTRACT CAPACITY
>
> The Contract Capacity shall be the kW of capacity specified in the Purchase Power Agreement. This term shall mean the maximum electrical output capability expressed on an alternating current basis of the generator(s) at any one time, at a power factor of approximately unity, without consuming VARs supplied by the Company, as measured at the Point of Delivery and shall be the maximum kW delivered to Company during any billing period. In cases where any change is required in the Company's facilities due to the actual capacity delivered exceeding the Contract Capacity or due to Seller requesting an increase in the capacity of the Company's facilities, Company may require Seller to execute a new Agreement or amend this Agreement to establish a new Contract Capacity. If the Company's facilities cannot be upgraded to accept such actual or requested increase, then upon written notice, Seller shall not exceed the existing Contract Capacity or such amount in excess thereof as Company determines it is able to accept.
>
> Seller shall not change its generating capacity without adequate notice to Company, and without receiving Company's consent. If an unauthorized increase in Seller's generating capacity causes loss or damage to the Company's facilities, the cost of making good such loss or repairing such damage shall be paid by Seller.
>
> Company may require that a new Contract Capacity be determined when it reasonably appears that the capacity of Seller's generating facility will deviate from contracted or established levels for any reason, including, but not limited to, a change in water flow, steam supply, or fuel supply.
>
> CONTRACT ENERGY
>
> The Contract Energy shall be the estimated annual energy production specified in the Power Purchase Agreement.

EARLY CONTRACT TERMINATION, REDUCTION IN CONTRACT ENERGY, AND INCREASE IN CONTRACT CAPACITY

Early Contract Termination

If Seller terminates the Power Purchase Agreement prior to the expiration of the initial (or extended) term of the Agreement, Seller shall pay to Company, the total Energy and/or Capacity Credits received in excess of the sum of what would have been received under the Variable Rate for Energy and/or Capacity Credits applicable at the first day of the term of the Agreement and as updated every two years, plus interest; provided, however, that Seller shall not be liable for such payment in the event that the Agreement is terminated due to a material default of Company. The interest shall be the weighted average rate for new debt issued by Company in the calendar year previous to that in which the Agreement was executed.

Reduction in Contract Energy

Beginning with the eighth year of the term of the Power Purchase Agreement, if at the end of any full calendar year during the term Seller has failed to deliver to Buyer at least seventy percent (70%) of the Contract Energy averaged over two consecutive calendar years on a rolling basis (the "Net Output Requirement"), the Company may petition the North Carolina Utilities Commission to invoke a Reduction-in-Contract-Energy Charge. If approved by the Commission, the Reduction-in-Contract-Energy Charge shall entitle Company to receive a monthly credit against the amount otherwise owed to Seller for the immediately following full calendar year determined by (a) multiplying (i) the difference between the Net Output Requirement and the actual Energy (expressed in MWh) delivered by Seller and received by Buyer during the applicable time period by (ii) twenty dollars ($20.00) and (b) then dividing the amount calculated by (a) above by twelve (12).

Where a Force Majeure Event adversely affects actual generation output of the Facility, the Net Output Requirement shall be reduced by the amount of energy not generated due to the Force Majeure Event; provided, however, Seller agrees that it must demonstrate to Company, in Company's commercially reasonable discretion, that the Facility's generation output was actually reduced due to a Force Majeure Event.

> If Seller fails to satisfy the Net Output Requirement for any two-year period, for the purpose of determining compliance with the Net Output Requirement in the next rolling two-year period, then the amount of energy generated in the first year of such two-year rolling period will be deemed to be the higher of (i) seventy percent (70%) of the Contract Energy for such year, or (ii) the actual amount of energy generated by the Facility in such year.
>
> Increase In Contract Capacity
>
> Seller may apply to Company to increase the Contract Capacity during the Contract Period and, upon approval by Company, future Monthly delivered capacities shall not exceed the revised Contract Capacity. If such increase in Contract Capacity results in additional costs associated with redesign or a resizing of Company's facilities, such additional costs to Seller shall be determined in accordance with the Interconnection Agreement.

Based on the foregoing, the Commission gives DEC and DEP the option of striking the provision or including the alternate provision indicated above.

<u>Increased Rights to Suspend and Terminate</u>

DEC and DEP have proposed to include in their Terms and Conditions, a provision taken from DEP's current terms and conditions. Under the provision, DEC and DEP may suspend or terminate the PPA: 1) for any default or breach of the contract by the QF; 2) for fraudulent or unauthorized use of the utility's name; 3) for failure to pay any applicable bills when due and payable; 4) for a condition on the QF's side of the point of delivery known or "reasonably anticipated" by the utility to be dangerous to life or property; or 5) due to the QF's inability to deliver the quality and/or quantity of electricity specified in the PPA.

NCSEA expressed concerns with the proposed provision. NCSEA Initial Comments, section III.B.e. Specifically, NCSEA pointed out that while the Terms and Conditions require the utility to give the QF advance notice of termination (except where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter), the Terms and Conditions provide no opportunity for the QF to cure the condition giving rise to termination. NCSEA pointed out that, by contrast, DNCP provides a 30-day cure period for most defaults. NCSEA also pointed out that in the 2012 Proceeding, DEP's standard contract did not include a cure provision and that DEP agreed to add the cure periods in response to comments filed by parties to that proceeding.

NCSEA also expressed concerns regarding the default provision that would allow DEC or DEP to terminate the power purchase agreement due to the QF's inability to deliver the quality and/or quantity of electricity specified in the PPA.

Specifically, NCSEA commented that the provision does not clearly define what the "quantity" and "quality" standards are that have to be met, that the provision does not define what degree of deviation from the "quality and/or quantity of electricity" specified in the contract (and for what period of time) justifies termination, and that QFs relying on variable energy resources lack control over production. Finally, NCSEA expressed concern regarding a lack of clarity regarding circumstances under which the utility would suspend versus when the utility would terminate a power purchase agreement. NCSEA Initial Comments, section III.B.e.

In its reply comments, the Public Staff expressed support for commercially reasonable cure periods. Public Staff Reply Comments, p. 11. In addition, the Public Staff expressed concerns regarding the default provision that would allow DEC or DEP to terminate the power purchase agreement due to the QF's inability to deliver the quality and/or quantity of electricity specified in the PPA, noting that such provision appears to be inconsistent with the Commission's decision in Docket No. E-100, Sub 59 in which it found that while a utility may require a QF to state the amount of energy or capacity it intends to provide, it cannot penalize the QF, particularly a QF that cannot control its fuel. Public Staff Reply Comments, p. 18.

Subsequent to the filing of reply comments, NCSEA, DEC and DEP reached a compromise on the issues of cure period and circumstances under which the utility would suspend versus terminate a power purchase agreement. Such compromise is set forth in the Settlement Letter, which explains that the default provision related to the QF's inability to deliver the quality and/or quantity of electricity specified in the PPA is not intended to penalize the QF when it is unable to deliver due to circumstances beyond its control, such as weather conditions, but rather that the intent of the provision is to allow for termination or suspension when events or circumstances within the QF's control, e.g. unrepaired equipment, result in the inability to deliver.

Thus, the Commission directs DEC and DEP to revise the DEC/DEP Terms and Conditions in accordance with the Settlement Letter.

<u>Limitation on Assignment Rights</u>

The DEC/DEP PPA provides that a QF's rights under the contract may only be assigned to a third party if the utility is "reasonably satisfied" that the assignee will fulfill its obligations under the agreement and if the assignee furnishes "a satisfactory guarantee for the payment of any applicable bills."

NCSEA expressed the concern that this provision gives the utility undue discretion to disapprove or put onerous conditions on the assignment of rights such the requirement of financial security, which as discussed in the context of DNCP's Standard Contract, have the potential to serve as an impediment to QF development. Therefore, NCSEA recommended that the Commission direct DEC and DEP to revise this provision to require that the utility will not unreasonably withhold consent and will not require commercially unreasonable measures, such as financial assurance. NCSEA Initial Comments, section III.B.f.

The Public Staff expressed similar concern and noted that in order to encourage QF development in compliance with PURPA, the Commission has included standard rates, terms, and conditions in its biennial avoided cost proceedings since Docket No. E-100, Sub 41A, to reduce the transaction costs for smaller project developers who may not have the resources or expertise to negotiate with a utility. The Public Staff expressed concern that the DEC/DEP assignment provision could constitute an unreasonable burden on QF development and that the provisions should be revised accordingly. Public Staff Reply Comments, p. 9.

The Commission agrees with the concerns expressed by NCSEA and the Public Staff and, therefore, directs DEC and DEP to revise the provision in the DEC/DEP PPA to make clear that the utility will not unreasonably withhold consent and will not require commercially unreasonable measures from the assignee, such as financial assurance.

Retroactive Modification of Terms and Conditions

NCSEA commented that DEC's and DEP's standard offer documents include contradictory provisions concerning the effect of government action and subsequent changes in law (and, in particular, Commission approval of revised regulations, terms and conditions) on existing contracts. NCSEA Initial Comments, section III.B.g.

NCSEA noted that the DEC/DEP PPA provides that although fixed long-term rate schedules incorporated in an existing contract may not be changed by subsequent orders of the Commission, other provisions "are subject to change, revision, alteration or substitution, either in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction."

NCSEA noted that the rate schedules similarly provide that, with the exception of fixed long-term rates, the "Rate Schedule and Terms and Conditions for the Purchase of Electric Power are subject to change, revision, alteration or substitution, either in whole or in part, upon order of the Commission or any other regulatory authority having jurisdiction."

NCSEA noted that the Terms and Conditions provide that "This Agreement shall at all times be subject to changes by such governmental agencies, and the parties shall be subject to conditions and obligations, as such governmental agencies may, from time to time, direct in the exercise of their jurisdiction, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract."

NCSEA expressed the concern that, when read together, these provisions leave unclear the specific terms that are subject to change when the Commission or any governmental agency takes subsequent action. NCSEA commented that allowing settled expectations, embodied in the agreement between the QF and the utility, to be upset by later actions of the Commission, or by any governmental action, would interfere with contractual rights, create uncertainty for investors, pose a barrier to financing and, effectively, discourage QF development. Therefore, NCSEA recommended that the Commission reject the provision that would allow terms and conditions of existing power purchase agreements to change as a result of subsequent government action.

DEC and DEP commented that the companies' standard offer documents are consistent with prior Commission precedent, pointing to the concerned raised in the 2012 Proceeding regarding a similar provision. DEC/DEP Reply Comments, p. 38. DEC and DEP comment that the inclusion of the language in the Terms and Conditions was done to be consistent with the Commission's direction in the 2012 Proceeding.

The Commission notes that in the 2012 Proceeding, DEC's proposed power purchase agreement[3] provided as follows:

> Said [Rate Schedule and] Service Regulations are subject to change, revision, alteration or substitution, whether in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction, and any such change, revision, alteration or substitution shall immediately be made a part hereof as though fully written herein, and shall nullify any prior provision in conflict herewith.

In the 2012 Proceeding, Public Staff noted that, historically, DEC's power purchase agreement had included a "Note" which provided as follows: "Note: 'Rate Schedule and' included in the above sentence for variable rates only." Because DEC's proposal in the 2012 Proceeding did not include the Note, because the Note had historically been included in the contract, and because PURPA requires the availability of fixed, long-term rates, DEC agreed to revise its power purchase agreement to include the following language:

> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all other provisions of the Rate Schedules and Service Regulations, including but not limited to Variable Rates, other types of charges (e.g., facilities charges), and all non-rate provisions.

[3] Prior to the 2014 Proceeding, DEC did not use stand-alone Terms and Conditions to accompany its power purchase agreement.

See 2012 Order, pp 39-40.

The Commission notes that this language now appears in the DEC/DEP PPA. The Commission notes that this language is the result of DEC's taking action to address concerns raised by the parties in the 2012 Proceeding and appreciates DEC's and DEP's efforts to this end in this proceeding. However, the Commission agrees with NCSEA that, read together, the various provisions related to subsequent government action present some confusion. While it is clear that the fixed rates are not subject to change, it is unclear whether, as written, the terms of the PPA are subject to change. The Commission notes that the proposed DEC/DEP Terms and Conditions, which provide that "This Agreement shall at all times be subject to changes by such governmental agencies, and the parties shall be subject to conditions and obligations, as such governmental agencies may, from time to time, direct in the exercise of their jurisdiction, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract" would allow changes in "non-essential terms and conditions" of the PPA without specifically identifying what constitutes an essential term or condition and what constitutes a non-essential term or condition. This lack of clarity is confusing, creates uncertainty, invites dispute and could constitute a barrier to financing and discouragement to QF development. For this reason, the Commission directs DEC and DEP to revise this provisions in the standard offer documents to make clear that subsequent government action will not change the rates or the terms and conditions of prior-executed power purchase agreements.

<u>Inclusion of Interconnection Terms</u>

NCSEA took exception to the inclusion by DEC and DEP of proposed changes to the DEC/DEP PPA, rate schedules, and Terms and Conditions related to interconnection. NCSEA Initial Comments, section III.B.h.

The Public Staff commented that since the Commission has adopted separate procedures, forms, and agreements in Docket No. E-100, Sub 101, related to the interconnection of QFs, there is no need for these additional terms to be added in the proposed standard offer documents, and doing so could result in confusion and inconsistencies. The Public Staff recommended that the Commission direct DEC and DEP to delete the provisions related to interconnection, with the exception of a reference to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101, and a statement that an interconnection agreement is necessary in order to deliver output to the utility.

In its Reply Comments, DEC and DEP commented that NCSEA and DEC and DEP agree that the inclusion of terms related to interconnection is intended to clarify that such terms control only when a QF is operating without an interconnection agreement. DEC and DEP indicated that when a QF is subject to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101 and, accordingly, has entered into an interconnection agreement, the interconnection agreement controls. DEC/DEP Reply Comments, 43. This resolution is reflected in the Settlement Letter.

Therefore, the Commission directs DEC and DEP to revise its standard documents as set forth in the Settlement Letter, to clarify that when a QF is subject to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101 and, accordingly, has entered into an interconnection agreement, the interconnection agreement controls in the event of a conflict.

Reactive Power

DEC's proposed Rate Schedule includes a provision, labeled "Power Factor Correction", pursuant to which DEC proposes to reduce the number of kWh for which payment is made if the "average power factor" of the QF falls outside the parameters specified in the rate without any commensurate credit to the QF when it produces reactive power (measured in volt-ampere-reactive or "VAR") that benefits DEC.

Similarly, DEP's proposed Rate Schedule includes a related provision pursuant to which DEP proposes to bill the QF at a rate of $0.34 multiplied by the number of kilo-VARs consumed or supplied by the QF. DEP's proposal contemplates that a QF may enter into an "Operating Agreement" with the utility to adjust VAR production to support voltage control. In their reply comments, DEC and DEP indicate that an "Operating Agreement" may be appropriate for "larger QFs" with the capability to provide direct voltage support but do not indicate the circumstances under which a utility would enter into such an agreement.

NCSEA stated that DEC and DEP's proposed Rate Schedule provisions related to reactive power are unclear. NCSEA Initial Comments, section III.B.i. NCSEA pointed out that DEC's Rate Schedule includes a provision, labeled "Power Factor Correction", pursuant to which DEC proposes to reduce the number of kWh for which payment is made if the "average power factor" of the QF falls outside the parameters specified in the rate without any commensurate credit to the QF when it produces reactive power (measured in volt-ampere-reactive or "VAR") that benefit DEC.

NCSEA pointed out that DEP's North Carolina Terms and Conditions for the Purchase of Electricity require that the "Seller's facility shall be operated in such a manner as to generate reactive power as may be reasonably necessary to maintain voltage levels and reactive area support as specified by Company." In addition, NCSEA pointed out that DEP's Rate Schedule contemplates that a QF may enter into an "Operating Agreement" with the utility to adjust VAR production to support voltage control; however, “Operating Agreement” is not defined in any of the standard documents.

The Public Staff pointed out that Section 1.8 of the Commission-approved North Carolina Interconnection Agreement specifies that an interconnection customer, with the exception of wind generators, must operate within a power factor range of 0.95 leading to 0.95 lagging at continuous rated power output, and that a utility is obligated to pay the interconnection customer when the utility requests the interconnection customer to operate outside of that range. The Interconnection Agreement further states that “if the Utility pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.”

The Public Staff recommended that the Commission require DEC and DEP to update their applicable rate schedules to reflect the utilities’ obligation to pay an interconnection customer for reactive power that the customer provides or absorbs at the utilities’ request.

In their reply comments, the companies explain that the reactive power provisions are intended to clarify that a QF is expected to operate in a manner that will not adversely impact voltage and further explain that QF’s without Operating Agreements are requested to operate at “unity” or a “100% power factor.” The companies’ reply comments make clear that QF’s not operating at a unity power factor will be charged for VAR consumption or supply using the same approach as used with retail customers. DEC/DEP Reply Comments, p. 39.

The Commission is convinced that the reactive power provisions are not clear, particularly in light of the Public Staff’s recommendation. The Commission recognizes that voltage support may be an important function of the QF and that the QF should be given the opportunity to provide such support. However, the Commission intends to consider this issue in a future proceeding. For the purposes of the current proceeding, the Commission directs DEC and DEP to revise the standard offer documents to clarify that QFs are required to operate at unity, that when not operating in unity they will be charged at a rate specified in the rate schedule, and that QFs that have entered into an Operating Agreement shall be governed by the terms and conditions of that Operating Agreement.

“Single, contiguous premises” Limitation

DEC’s and DEP’s Rate Schedules propose to limit availability as follows:

> Service necessary for the delivery of power from the Seller’s generating facilities into Company’s system shall be furnished solely to the individual contracting Seller in a single enterprise, located entirely on a single, contiguous premise.

NCSEA commented that there is no legitimate basis upon which the Commission should approve the limitation that the QF be located on a "single, contiguous premise." As an initial matter, "single, contiguous premise" is not defined in the Rate Schedules. Moreover, the Commission has held, most recently in its Order Setting Parameters, that the Commission-approved standard offer rates and contract terms are available to QFs of up to 5 MW of capacity (with certain exceptions based on energy resource). Additionally, as a practical matter, there are times when a 5 MW QF must be located on more than one parcel of property or located on a parcel of property that is bisected by a public right of way. Whether either of these examples would run afoul of DEC's and DEP's proposed limitation is not clear. NCSEA pointed out that DEC and DEP have proposed one-half mile limitations, to which NCSEA does not object, as discussed above in greater detail. The "single, contiguous premise" limitation has the potential to be more restrictive than the one-half mile limitation. For these reasons, NCSEA recommended that the Commission reject this proposed limitation on availability. NCSEA Initial Comments, section III.B.j.

In their reply comments, DEC and DEP argued that "[a]s with several of the other provisions in the Companies' proposed PPA, Standard Terms and Conditions, and Rate Schedules, NCSEA strains to find some perceived adverse impact from this provision, concludes it must be intended to restrict QF development, and recommends its removal." DEC/DEP Reply Comments, p. 40. The companies stated further that the provision does not preclude a QF's ability to wire its site to a single point of interconnection and is intended to minimize the cost of providing service to a site.

The Commission agrees with NCSEA that single, contiguous premise is not defined and, for this reason, application of this provision would be problematic and invite dispute. Further, the Commission concludes that DEC/DEP do not adequately explain how the provision has the effect of minimizing the cost of providing service to a site. Because the utilities have not provided justification for the revision, it must be struck.

<u>Reporting Requirements</u>

In the Public Staff's Initial Statement, the Public Staff expressed concern regarding DEC's and DEP's proposed provision in the DEC/DEP PPA that requires a QF larger than 100 kW in nameplate capacity to provide notice to the utility of annual, monthly, and day-ahead forecasted hourly production. The Public Staff indicated that after consultation with DEC and DEP, the utilities have agreed to the following provision, in lieu of the initial proposal:

> Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. If the Seller is required to notify the Company of planned or unplanned outages,

> notification should be made as soon as known. Seller shall include the start time, the time for return to service, the amount of unavailable capacity, and the reason for the outage.

Public Staff's Initial Statement, p. 54.

In its reply comments, NCSEA recognized that accurate production data is valuable for utility system operations and that the intent of the provision is to give the utility ample notice regarding QF production to allow the utility to plan and dispatch generation accordingly. For these reasons, NCSEA did not oppose the reporting requirement as it relates to QF outages, planned or unplanned. However, NCSEA expressed concerns regarding the production forecast requirements agreed to by the Public Staff and DEC and DEP. NCSEA Reply Comments, section IV.

NCSEA commented that accurate hourly production forecasts for QFs that rely on variable resources such as solar, wind and streamflow require sophisticated meteorological analysis. Moreover, the cost associated with production forecasting based on current, short term forecasts is prohibitive at this point in time for most small QFs. NCSEA acknowledged that while the QF is in the better position to provide information regarding outages, the Utilities are in the better position to forecast production, given their meteorological capabilities and resources used to operate their systems. As the Utilities have superior forecasting resources and capabilities to those of the QF, the likelihood of reliance by a utility on production forecasts provided by a QF is very low. Because any benefits that may result from the requirement that a QF provide production forecasts are not commensurate with the burdens on a small QF, NCSEA recommended that the Commission reject the proposal as relates to production forecasting. However, in recognition of the value to the Utilities of accurate production forecasts, NCSEA recommended that the issue of production forecasting be revisited in a future proceeding at a point in time when the forecasting tools available to QFs have improved and become more cost effective, such that the disparity between the capabilities of the Utilities and the QFs has decreased and the likelihood that the QF production forecasts will be relied upon by the Utilities has increased.

NCSEA commented that if the Commission is inclined to grant the request of Public Staff and DEC/DEP related to production forecasts, NCSEA requested that the Commission consider the following language, which reflects the fact that QFs routinely develop hourly production projections as part of the design/development process, which are based on the specific design location of a specific site and long-run, average meteorological data from a local meteorological station. NCSEA's alternative proposal was as follows:

> Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production. The forecasts of production developed during the

> design and development process of the Facility may be used by the Seller to satisfy its obligations hereunder. Any inaccuracies in the forecasts of production shall not give rise to a right to terminate the Agreement by Company.

NCSEA also recommended that the proposal be further revised to make clear that a QF may rely on the production forecasts produced during the design/development process to fulfill its obligations under the contract provision and that any inaccuracy in the forecasts shall not give rise to a right to terminate by the respective utility. NCSEA Reply Comments, section IV.

The Commission has considered the arguments raised by the parties and concurs that a reporting requirement is appropriate to aid the Utilities in scheduling the operation of other generation resources. Clearly, the QF is in the best position to provide its outage schedule and to identify the duration of both planned and unplanned outages. The Commission agrees that for variable resources, such as solar, wind and streamflow, a precise hourly forecast of production is difficult, but this does not appear to be the intent of the provision. The QF should provide its best estimate of production but shall be held harmless if such production estimate is in error due to factors beyond its control such as the availability of solar, wind or streamflow. The Commission therefore concludes that the revised provision tendered by the Public Staff and Utilities shall be approved, revised further to reflect that QFs that rely on variable resources shall be held harmless if such production estimate is in error due to factors beyond its control such as the availability of solar, wind or streamflow.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 15

The regulations of the FERC implementing PURPA establish that, in selling its electrical output to the utility, the QF may elect to:

> provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> i) the avoided costs calculated at the time of delivery; or
>
> ii) the avoided costs calculated at the time the obligation is incurred.

18 C.F.R. § 292.304(d)(2). In explaining a QF's options for selling its output, the FERC has provided that:

> [A] QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA. Accordingly, a QF, by committing itself to sell to an electric utility also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.

J.D. Wind 1, LLC, 129 FERC ¶ 61,148 (2009) (JD Wind 1) ¶ 25. It has been the FERC's long-standing practice to "leave to state commissions the issue of when and how a legally enforceable obligation [(LEO)] is created." See J.D. Wind 1, reconsideration denied, 130 FERC ¶ 61,127 (2010), ¶ 24. To this end, the Commission has previously ruled that a LEO is created when a QF: 1) has received a certificate of public convenience and necessity (CPCN); and 2) has committed itself to sell to the utility. See Order Denying Request for Waivers, N.C.U.C. Docket No. SP-4158, Sub 0, June 15, 2015, p. 6; 2012 Order, p. 35; Order on Motion to Suspend Avoided Cost Rates, N.C.U.C. Docket Nos. E-100, Sub 127 and E-100, Sub 136, December 21, 2012, p. 3.

During the first phase of this proceeding, DNCP witness Williams testified as to DNCP's position that the test for establishing a LEO is "too vague to be implemented in a fair manner, particularly with regard to the second prong of the test, as there is not enough guidance regarding what it means for a QF to " 'commit itself to sell its output.' " Order Setting Parameters, p. 63. DNCP proposed the use of a form as a means to clarify this second prong of the test. In response to DNCP's proposal, the Commission noted that "no party expressed any opposition to it, but neither did any party express any support" and indicated an inclination to move toward this approach. Order Setting Parameters, p. 64. Therefore, in the Order Setting Parameters, the Commission ordered that:

> DNCP's proposal for a simple form to be used to determine the date of the commitment of a QF, along with how it should be implemented shall be approved with the details and implementation to be considered in the next phase of this proceeding and the parties are directed to address it in their filings.

With its March 2015 Filing, DNCP proposed a form. The Public Staff and NCSEA took issue with this form, particularly that the form was unnecessarily complicated, appeared to be a contract as opposed to a simple notice form, and required more information than necessary to indicate a commitment on the part of the QF. Public Staff Initial Statement, pp 51-54; NCSEA Initial Comments, section IV.

Following the filing of initial statements and comments, DNCP, NCSEA, DEC, DEP, and the Public Staff worked together in attempt to develop consensus on a simple form that would: (1) provide sufficient guidance regarding what it means for a QF to "commit itself to sell its output", as discussed by DNCP witness Williams in Phase One of this proceeding; and (2) address the comments of and issues raised by DEC, DEP, NCSEA, and the Public Staff regarding the contents of the form. Public Staff Reply Comments, pp 20-21.

On September 10, 2015 the Public Staff filed a letter in this docket indicating that the Public Staff, DEC, DEP, DNCP and NCSEA agree on certain sections of the form filed by DNCP as Exhibit E to its August 7, 2015 Reply Comments (the "DNCP Commitment Form") and disagree on other sections of the DNCP Commitment Form. Specifically, the parties reached consensus on sections 1 through 4 of the DNCP Commitment Form but did not reach consensus on sections 5 and 6 of the DNCP Commitment Form.

On September 17, 2015, DEC/DEP filed a letter in this docket including a proposed Commitment Form applicable to QFs seeking to sell their output to those utilities (the "DEC/DEP Commitment Form"). The DEC/DEP Commitment Form is similar to the Commitment Form, except that Sections 5 and 6 of the DEC/DEP Form, respectively, contain additional acknowledgements and conditions of termination.

Section 5 of the DNCP Commitment Form is a proposed acknowledgment by the QF as to the date on which the LEO is created. NCSEA argued that requiring the QF to make certain acknowledgments in the form results in the form's resembling a contract, as opposed to a form in which the QF makes a declaration. NCSEA Initial Comments, section IV.B. Section 5 of the DEC/DEP Commitment form includes additional acknowledgements relating to the establishment, expiration, and termination of the QF's commitment to sell. The Commission agrees with NCSEA's concern (which applies to both the DNCP Commitment form and to the later-filed DEC/DEP Commitment Form) and notes that a contract would contravene the FERC's clear guidance provided in JD Wind I that the LEO is a non-contractual obligation. JD Wind 1, ¶ 25.

Because the purpose of the form is merely for the QF to indicate that it is committing itself to sell to the utility, acknowledgments are unnecessary. Because it is within the purview of the Commission to articulate when and how a LEO is established, the form need not include such verbiage. For these reasons, Section 5 of both the DNCP Commitment Form and the DEC/DEP Commitment Form must be struck.

Section 6 of the DNCP Commitment Form and the DEC/DEP Commitment Form addresses circumstances under which the commitment by the QF terminates. Because a commitment to sell is one of the requirements for establishing a LEO, the termination of a commitment to sell would effectively terminate any associated LEO. NCSEA took issue with the section of the form dealing with termination on the basis that neither federal law and precedent nor the Commission's precedent support the proposition that a LEO is terminated after a specific period of time or upon the happening of a specific event. NCSEA Initial Comments, section IV.C.

The Commission agrees with NCSEA that the Commission has never provided clear and generally applicable rules regarding the termination of a commitment or the termination of a LEO. This issue raises complex legal and policy questions that have not been briefed by the parties in this proceeding. In addition, the issue of whether a commitment has been terminated is highly dependent on facts and circumstances and does not lend itself to a one-size fits all, generally applicable resolution.

For example, Section 6(a) of both the DNCP Commitment Form and the DEC/DEP Commitment Form provides that the commitment to sell (and thus the corresponding LEO) terminates upon execution of a PPA between the QF and the utility. That rule, however, would be unfair and inconsistent with PURPA if applied in all situations. For example, if entry into a PPA terminates a LEO, and a PPA is terminated by a QF due to a *utility's* default, it would result in a QF, by no fault of its own, having its LEO terminated and having to obtain a new LEO at later-established avoided cost rates. On the other hand, allowing a LEO to last indefinitely, regardless of the terms agreed to in a PPA, creates possibilities for gamesmanship by both QFs and utilities. And while the Commission has provided clear guidance on the similar issue of availability of rates for small QFs, giving them at least 30 months from the date of a Commission order establishing avoided cost rates to begin delivering power pursuant to those rates (see 2012 Order, pp 37-38), the parties to this proceeding have not had the opportunity to present their positions on whether such a time frame would be appropriate for QFs not eligible for standard rates.

In addition, the Commission observes that the termination of a commitment, and by extension a LEO, based on a QF's failure to execute a bilateral PPA within 6 months (as provided in Section 6(c) of DNCP's Commitment Form) or 90 days (as in Section 6(b)(iii) of DEC/DEP's Commitment Form) would be inconsistent with the FERC and Commission precedent holding that the purpose of a LEO is to protect QFs from conduct by utilities that might "frustrate a QF's exercise of its PURPA rights." In the Matter of EPCOR USA North Carolina LLC, Docket No. E-2, Sub 966 (Order on Arbitration issued Jan. 26, 2011) at 8 (citing JD Wind 1).

In sum, the Utilities have not established any legal basis for requiring that a commitment terminate under any of the circumstances set out in Section 6 of the commitment forms. The termination of a commitment, and therefore a LEO, raises complex issues that should not be resolved by this Commission without affording all parties the opportunity to be heard on the issue of termination. Moreover, whether a commitment has been terminated necessarily involves a fact-specific inquiry and does not lend itself to a generally applicable rule. For these reasons, Section 6 of the DNCP and DEC/DEP Commitment Forms must be struck.

With respect to the termination of a commitment, the Commission concludes, as stated above, whether a commitment has been terminated necessarily involves a fact-specific inquiry and does not lend itself to a generally applicable rule.

Therefore, the Commission directs the Utilities to revise their respective forms to include only sections 1 through 4. Sections 1 through 4 create a "simple form" that can be used to determine the date of the commitment of a QF, which is consistent with DNCP's initial position made in the first phase of this proceeding and which is consistent with Ordering Paragraph 17 of the Order Setting Parameters. The form shall not include any provisions beyond those set forth in sections 1 through 4.

With respect to whether use of the form should be mandatory or permissive, DNCP proposed that the use of the form be mandatory. Under DNCP's approach, QFs will have failed to establish an LEO if a form is not completed or is not completed correctly. DNCP March 2015 Filing, Section I.A, p. 5. The Public Staff agreed that the form should be mandatory but that the QF be given an opportunity to cure any errors in the form. Public Staff Reply Comments, pp 21-22. In contrast, NCSEA proposed that use of the form by a QF be permissive rather than mandatory. NCSEA suggested that the Commission incent the use of the form by holding that, on a prospective basis: a) a QF's use of the form will give rise to a rebuttable presumption in favor of the QF that it has committed itself to sell to the utility as of a date certain – i.e., the date a QF transmits the form to the relevant utility; and b) a QF's failure to use the form will give rise to a rebuttable presumption in favor of the utility that the QF has not committed itself to sell to the utility. NCSEA Initial Comments, section IV.A.

The Commission is persuaded by NCSEA's arguments that making use of a form the exclusive means for establishing a commitment institutionalizes rigidity that elevates form over substance and has the potential to result in unfair outcomes. Despite stakeholders' best intentions, atypical factual situations are likely to arise, and the Commission sees fit to preserve flexibility to address these situations on a case-by-case basis so that fairness triumphs over form. The Public Staff's advocacy for an opportunity to cure errors goes to this concern, but the Commission is concerned that affording QFs an opportunity to cure may itself invite dispute and eventual involvement of the Public Staff and Commission.

With respect to implementation of a form, in the Order Setting Parameters, the Commission requested comment on the following issues: i) how the QF would know it needed to obtain the form; ii) how the QF would obtain the form; iii) whether or how the form could be submitted electronically; and iv) the extent to which the utility could change or withdraw the form without prior Commission approval. Order Setting Parameters, p. 64.

As to these issues, the Commission has considered the comments of the parties and instructs as follows:

i. To ensure that a QF knows of the availability of the form, the Utilities are directed to include language regarding use of the form and a weblink to the form: a) on their websites in both the sections for interconnection agreements and PPAs; and b) in any "standard" instructions typically provided to QFs via mail or e-mail.

ii. A QF would obtain the form by accessing the Utilities' websites, in sections dealing with interconnection agreements and with PPAs. If a utility changes the filename or location of the form on its website, it must ensure that the old link continues to function for a commercially reasonable period of time.

iii. The Utilities are directed to accept forms via e-mail at an e-mail address publicly available on the form and on the utility's website. The Utilities may allow the forms to be transmitted via website. If a utility allows forms to be submitted via website, it shall reply to the applicant with an e-mail confirming receipt of the form within 24 hours of submittal; however, the submittal date, when submitted via website, shall be the date of submittal. Because web-based forms have limitations (such as the potential for server downtime, or text form fields that do not allow enough space to enter all relevant information) other methods for transmitting the form, such as e-mail, hand delivery, U.S. mail, etc. also must be available to the QF.

iv. If a utility makes anything other than minor administrative changes to the form, the utility must file such revisions for approval by the Commission. Minor administrative changes, including routing information (such as the e-mail address to which the form must be sent), do not require Commission approval. However, a utility should promptly notify the Commission of any minor administrative changes and ensure that the old information remains valid for a commercially reasonable period of time.

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 16

The Commission notes that, in addition to requiring the Utilities to base their hypothetical CT costs on publicly available industry sources, the Utilities have a PURPA obligation to make their avoided cost calculation data – including their tailored hypothetical CT cost data – available for public inspection.

In providing a summary of its regulations implementing PURPA, the FERC has explained that:

> These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting 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. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

45 Fed. Reg. 12,214, 12,215 (February 25, 1980) (Order No. 69).

Section 292.302 of the FERC's regulations governs the availability of electric utility system cost data. Section 292.302(b) provides as follows:

> General rule. To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain <u>for public inspection</u>**,** and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:
>
>> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>>
>> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>>
>> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on

> the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

18 C.F.R. § 292.302(b). The FERC explained its intent in adopting section 292.302(b) as follows:

> [A]n investor needs to be able to estimate with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.304 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs, taking into account the factors set forth in paragraph (e) of that section. Section 292.302 of these rules is intended by the Commission to assist those needing data from which avoided costs can be derived. It requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system.

Order No. 69, ¶ 31,171.

The FERC's regulations provide the Commission with discretion to require disclosure of a different set of data, so long as avoided costs can still be derived from such data. Specifically, section 292.302(d) provides, in relevant part, as follows:

> (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

18 CFR § 292.302(d)(1).

Further, in explaining its ability to penalize electric utilities for failing to comply with the public disclosure requirements of its regulations, the FERC emphasized the importance of public disclosure of these data:

> As stated earlier in this preamble, the data required by § 292.302 will form the basis from which the rates for purchases will be derived; § 292.302 is thus a critical element in this program. [FERC] believes that, with regard to utilities subject to section 133 of PURPA, [FERC] may exercise its authority under section 133 to require the data

> required by § 292.302(b) on the basis that [FERC] finds such information necessary to allow determination of the costs associated with providing electric services.

Order No. 69, ¶¶ 30,340-30,341.

NCSEA pointed out that, in this proceeding, DNCP has made an effort to use data from publicly available sources and to file for public inspection the data underlying its avoided capacity cost calculation, with a narrative explanation that identifies the publicly available industry sources on which DNCP relied. NCSEA Initial Comments, section V.B. NCSEA also pointed out that DNCP's Avoided Cost Information Required by 18 C.F.R. § 292.302(b)(1)-(3), filed in this docket on March 2, 2015, does not redact any cost data. The Commission takes note of DNCP's effort in this regard.

NCSEA pointed out that DEC and DEP failed to file for public inspection much the data underlying their avoided cost calculations. NCSEA Initial Comments, section V.B. NCSEA noted that the failure to disclose by DEC and DEP significantly delayed NCSEA's ability to analyze DEC's and DEP's March 2015 Filings, since NCSEA had to resort to the discovery process to obtain data, much of which was marked as "confidential" when provided. NCSEA Initial Comments, section V.B. NCSEA also pointed out that DEC and DEP's Avoided Cost Informational Filing, filed in this docket on December 23, 2014 pursuant to section 292.302(b)(3) of the FERC's regulations ("DEC/DEP Informational Filing"), redacts cost data.

Similarly, SACE pointed out that:

> In their March 2, 2015 filings, neither DEC nor DEP disclosed the data underlying their calculations of the installed cost of a CT. Instead interested parties had to resort to data requests to obtain this information, much of which was marked as "confidential" when provided.

SACE Initial Comments, section B.2.

In their reply comments, DEC and DEP asserted that, despite the FERC regulations, their redactions were appropriate under the North Carolina Trade Secrets Protection Act and the North Carolina Public Records Act, which together permit "trade secrets" to be filed under seal in North Carolina. Specifically, DEC and DEP noted that:

> A review of NCSEA comments, however, reveals that it failed to cite to G.S. 66-152(3) which defines a "trade secret" under North Carolina law. The Companies contend, for the reasons discussed earlier, that some of the data used to calculate avoided costs is a trade secret,

> and, as such, they redacted the information as is allowed by the Commission pursuant to G.S. 132-1.2.

DEC/DEP Reply Comments, p. 44.

At least one state utilities commission has entertained arguments regarding whether, given the FERC's regulation, a utility may file capacity and energy cost information under seal pursuant to a state trade secret protection law. In 1995, the Maine Public Utilities Commission (PUC) entertained a challenge to a utility's confidential filing of cost information. Ruling on Request for Protective Order, Maine PUC Docket No. 92-315, 1995 Me. PUC Lexis 11, January 27, 1995 (Maine PUC Order). In addressing the challenge, the Maine PUC order provided, in relevant part, as follows:

> Federal regulations (issued pursuant to the Federal Power Act) do not preclude state law trade secret protection of the avoided cost information filed in this case. <u>(The regulations most likely do preclude state law trade secret protection of the biennial filings specifically described in the regulations.)</u>
>
> . . . .
>
> <u>Plainly, under this federal regulation, the specified avoided cost information must be filed with state regulatory agencies and the information must be publicly available. The federal regulation expressly regulates state activities and, under the supremacy clause, undoubtedly precludes any state action that would make the specified information not publicly available, e.g., pursuant to state trade secret protection law.</u> Nevertheless, we find that the avoided cost data included in CMP's filing in this case does not constitute the biennial filing described in the federal regulation and is therefore not subject to its public availability requirement. <u>The requirement that the specified data be "maintain(ed) for public inspection[''] rather clearly refers to the filing that a utility must make "not less often than every two years" with the utility's "state regulatory authority."</u> It does not refer to avoided cost data that is filed with a state commission for other purposes, e.g., the avoided cost data in this case.

Maine PUC Order, p. 3, 13 (emphasis added).

The Commission subscribes to the sentiment expressed in the Maine PUC order that section 292.302 "expressly regulates state activities and, under the supremacy clause, undoubtedly precludes any state action that would make the specified information not publicly available, e.g., pursuant to state trade secret protection law." As such, the Commission concludes that the North Carolina Trade Secrets Protection Act and the North Carolina Public Records Act cannot be utilized to override the mandate in section 292.302(b) that, every two years, a regulated electric utility must file and maintain for public inspection specific data from which the utility's avoided costs may be derived.

With regard to the exact data that DEC and DEP must maintain for public inspection, the Commission notes that section 292.302(d) of the FERC's regulations provides, in relevant part, that "any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority) . . . data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data. 18 CFR § 292.302(d)(1).

In light of the facts that avoided capacity costs calculated pursuant to the peaker method are based on a "hypothetical CT" and that DEC and DEP do not use the unit-specific information redacted from the DEC/DEP Informational Filing when calculating avoided costs, the Commission invokes section 292.302(d)(1), first, to direct DEC and DEP to file and maintain for public inspection the cost data associated with the "hypothetical CT" used to support each utility's proposed rates and, second, to uphold DEC's and DEP's redaction of certain unit-specific cost data from the DEC/DEP Informational Filing so long as the utilities make the alternate "hypothetical CT" data available for public inspection.

IT IS, THEREFORE, ORDERED as follows:

1. DEC, DEP, and DNCP shall offer long-term fixed and levelized capacity payments and energy payments for five-year, ten-year, 15-year and 20-year periods as standard options to (a) 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 and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass 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. DEC, DEP, and DNCP should offer their standard five-year levelized rate option to all other QFs contracting to sell three MW or less capacity.

2. DEC, DEP and DNCP shall recalculate their avoided energy costs using:

   a. The fuel price forecasts used and approved in their 2014 IRPs; and

b. Generation expansion plans that do not take into account any costs associated with the control of carbon dioxide emissions.

3. For the purposes of this proceeding, DEC, DEP and DNCP shall add 0.09 cents per kWh to their respective energy credits, as a reasonable estimate of the fuel price hedging benefits associated with QF generation.

4. DEC, DEP and DNCP shall recalculate their avoided capacity costs as follows:

a. DNCP shall not substitute the lower cost Siemens CT for the GE 7FA CT included in the Brattle Report; and

b. DEC, DEP and DNCP shall remove adjustments for economies of scope; and

c. DEC and DEP shall use a contingency factor of 15%; and

d. DEC and DEP shall use the useful CT life indicated in the EPRI TAG; and

e. DNCP shall use a useful CT life of 36 years, as indicated in the report, filed for public inspection, related to DNCP's fleet of CTs.

5. DEC, DEP and DNCP shall recalculate rates, using the same weighting to summer and non-summer months as was used in the 2012 Proceeding.

6. DNCP, DEC and DEP shall revise their respective rate schedules, power purchase agreements and terms and conditions as set forth herein.

7. The Utilities shall provide a commitment form, which shall include section 1 through 4 as set forth in the DNCP Commitment Form, to QFs, consistent with the guidance given herein, as a means, but not the exclusive means, to establish a QF has committed to sell its output to the utility. A QF's use of the form will give rise to a rebuttable presumption in favor of the QF that it has committed itself to sell to the utility as of a date certain – i.e., the date a QF transmits the form to the relevant utility. A QF's failure to use the form will give rise to a rebuttable presumption in favor of the utility that the QF has not committed itself to sell to the utility.

8. DEC and DEP shall file for public inspection, no later than 5 days from the date of this Order, the capacity ($/kW) and energy (cents/kWh) cost data associated with the "hypothetical CT" underlying the capacity cost calculation. So long as DEC and DEP file the hypothetical CT data for public inspection in

accordance with this decretal, the redaction of unit-specific cost data in the DEC/DEP Informational Filing is appropriate.

9. In future biennial avoided cost proceedings, the Utilities shall file for public inspection, at the time of filing of proposed rates, all data underlying the avoided cost calculations for their hypothetical CTs consistent with the FERC's regulations implementing PURPA.

10. The Utilities shall file revised rate schedules, power purchase agreements and terms and conditions, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

11. WCU's and NRLP'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 long-term avoided cost rates for QFs interconnected at distribution is approved. WCU's and NRLP's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed five, ten, and 15-year avoided capacity rates.

ISSUED BY ORDER OF THE COMMISSION.

This the __ day of ______________, 2015.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount, Chief Clerk

CERTIFICATE OF SERVICE

The undersigned certifies that she has served a copy of the foregoing **NCSEA'S PROPOSED ORDER** upon the parties of record in this proceeding, or their attorneys, by electronic mail.

18th day of September, 2015.

/s Charlotte A. Mitchell
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