NC SUSTAINABLE
ENERGY ASSOCIATION

June 22, 2017

Ms. Martha Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, NC 27603

Re: Proposed Order of the North Carolina Sustainable Energy Association
Docket No. E-100, Sub 148

Dear Ms. Jarvis:

Please find attached a copy of the Proposed Order of the North Carolina Sustainable Energy Association ("NCSEA") in the above-referenced docket. A copy of the brief in Microsoft Word format will be submitted to briefs@ncuc.net. Please do not hesitate to contact me with any questions or comments. Thank you in advance for your assistance and cooperation.

Sincerely,

/s/ Peter H. Ledford

CERTIFICATE OF SERVICE

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

This the 22nd day of June, 2017.

/s/ Peter H. Ledford

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	NCSEA'S
Electric Utility Purchases from	)	PROPOSED ORDER
Qualifying Facilities – 2016	)	

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

APPEARANCES:
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For the Using and Consuming Public:

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

BY THE COMMISSION: These proceedings are 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.

The following parties intervened with the permission of the Commission: the North Carolina Sustainable Energy Association (NCSEA); the Public Works Commission of the City of Fayetteville; Strata Solar, LLC; the Southern Alliance for Clean Energy (SACE); the Carolina Utility Customers Association, Inc.; the Carolina Industrial Group for Fair Utility Rates I, II, and III; the North Carolina Pork Council; O2 EMC, LLC; Cypress Creek Renewables, LLC (CCR); and NTE Carolina Solar, LLC.

On June 22, 2016, the Commission issued the Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing: 1) making Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU), and New River Light and Power Company (New River) (collectively, the Electric Utilities) parties to the proceeding; 2) determining that it would attempt to resolve all 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 written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing; and 3) directing the Electric Utilities to file on or before Tuesday, November 1, 2016 i) a set of proposed rates for purchases from QFs, showing all calculations for deriving said proposed rates, including inflation rates and discount rates used, and ii) proposed standard form(s) of contract between QFs and the utility, describing any differences between said proposed standard form(s) of contract and the currently approved standard contract (the Initial Statement). The Commission’s order also scheduled a public hearing and established a procedural schedule for the filing of comments by parties to the proceeding.

DEC, DEP and DNCP moved for and were granted an extension of time to file their Initial Statements until November 15, 2016.

On November 15, 2016, DEC, DEP and DNCP filed public and confidential versions of their Initial Statements. On November 28, 2016, WCU and New River filed their Initial Statements.

On December 20, 2016, NCSEA filed a motion seeking to strike as irrelevant or immaterial to this proceeding certain material in the initial statements and exhibits of DEC, DEP, and DNCP. On January 4, 2017, DEC and DEP and DNCP filed responses to NCSEA's motion.

On December 22, 2016, the Public Staff filed a motion requesting that the Commission issue an order establishing a new procedural schedule, including an evidentiary hearing.

On December 30, 2016, the Commission issued an order amending the procedural schedule by scheduling an evidentiary hearing for April 18, 2017 and establishing the deadlines for the filing of testimony by parties to the proceeding.

On January 18, 2017, the Commission issued an order denying NCSEA's motion.

On February 21, 2017, DNCP filed the direct testimonies and exhibits of J. Scott Gaskill and Bruce E. Petrie.

On February 21, 2017 DEC and DEP filed the direct testimonies and exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman III and Gary Freeman.

A public hearing was held on February 21, 2017 in Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina from 9:00 – 9:43 a.m., during which twelve public witnesses presented testimony.

On March 28, 2017, pursuant to several subsequent orders further amending the procedural schedule: NCSEA filed the direct testimonies of Ben Johnson, Carson Harkrader and Kurt Strunk; the Public Staff filed the direct testimonies of John Robert Hinton, Jay Lucas and Dustin Metz; CCR filed the direct testimony of Patrick McConnell; and SACE filed the direct testimony of Thomas Vitolo.

On April 10, 2017, pursuant to a subsequent order further amending the procedural schedule, DEC and DEP filed the rebuttal testimonies and exhibits of Kendal Bowman, Glen Snider, John Holeman III and Gary Freeman. DNCP filed the rebuttal testimonies and exhibits of J. Scott Gaskill and Bruce E. Petrie.

Beginning on Tuesday, April 18, 2017 through Friday, April 21, 2017, an evidentiary hearing was held in Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina.

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

FINDINGS OF FACT

COMPETITIVE PROCUREMENT PROCESS

1. A competitive procurement process, approved and overseen by the Commission and administered by an independent evaluator, is a reasonable means to encourage QF development in North Carolina, at this time.

STANDARD OFFER

2. Until such time as there is a Commission-approved competitive procurement process underway for the electric utility, 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 Offer). The standard levelized rate options of ten or more years should include an option to renew on substantially the same terms and conditions and at a rate either (a) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided costs and other relevant factors or (b) 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.

3. 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 following conditions: (a) any QF choosing to enter into a contract using the PJM market pricing method will be allowed to terminate its existing Schedule 19-LMP contract without paying termination charges after the first year upon 90-days prior written notice and, in doing so, enter into a new five-year, ten-year, or 15-year Schedule 19-FP contract at its option; and (b) DNCP is required to calculate avoided cost payments under each method for the next two years and report the resulting comparison to each QF and the Commission.

4. DEC, DEP, and DNCP shall offer QFs not eligible for the Standard Offer the following three options if the electric utility has a Commission-approved competitive procurement process underway: (a) participating in the electric utility's competitive procurement 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 Commission-approved competitive procurement process 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; 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 a Commission-approved competitive procurement process 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 a Commission-approved competitive procurement process 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 competitive procurement process underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

5. At such time when there is a Commission-approved competitive procurement process underway for the electric utility, the threshold at which a QF qualifies for the Standard Offer shall be reduced to one (1) MW.

PEAKER METHODOLOGY

6. The proposal by DEC and DEP to ascribe avoided capacity value to a QF only in those years in which the electric utility shows a need is fundamentally inconsistent with the peaker method and is, therefore, not appropriate as long as the peaker method is used to calculate avoided costs.

7. DNCP's proposal to ascribe no capacity value to the QF is fundamentally inconsistent with the peaker method and is, therefore, not appropriate as long as the peaker method is used to calculate avoided costs.

8. The method by which avoided costs are calculated should remain consistent in both standard and negotiated contracts, and if a method is not applicable to calculating the avoided costs of a "small" QF, the fact that a QF is a "large" QF does not validate such a method.

9. The avoided cost calculation methodology established in this proceeding impacts utility programs other than those related to their PURPA obligation.

AVOIDED ENERGY COSTS AND RATES

10. The proposal by DEC and DEP to rely exclusively on forward prices when developing fuel forecasts for the purposes of calculating avoided energy costs is inappropriate.

11. The proposal by DEC and DEP to reset energy rates every two years is not consistent with PURPA's objective of encouraging QF development.

12. The proposal by DNCP to adjust avoided energy rate to reflect locational value is not appropriate at this time but requires additional study for future consideration.

13. The proposal by DEC, DEP and DNCP to eliminate the value of avoided line loss is not appropriate at this time but requires additional study for future consideration.

14. QF solar generation benefits the electric utility during off-peak hours, and, for this reason, it is appropriate for DEC, DEP and DNCP to offer a separate avoided energy rate for solar QFs that more accurately reflects costs avoided by the electric utility during off-peak daytime hours.

AVOIDED CAPACITY COSTS AND RATES

15. The proposal by DEC and DEP to reduce the performance adjustment factor (PAF) from 1.2 to 1.05 is not appropriate.

16. The proposal by DEC and DEP to modify the allocation of avoided capacity costs between winter and summer months is not appropriate.

LEGALLY ENFORCEABLE OBLIGATION

17. In order for a QF to establish a legally enforceable obligation ("LEO"), the QF must: 1) have been granted a certificate of public convenience and necessity; and 2) transmitted a Notice of Commitment form to the purchasing electric utility. It is appropriate to require that, before a QF is eligible to transmit the Notice of Commitment form to the purchasing utility until the earlier of: 1) the QF's receipt of the interconnecting utility's System Impact Study for the QF; or 2) 105 days after the QF submits a complete interconnection request to the interconnecting utility.

18. It is not appropriate to establish different criteria for establishing a LEO for large QFs and small QFs.

CURTAILMENT

19. The discontinuance of purchases from QFs is authorized under 18 C.F.R. § 202.307(b) during any system emergency, if such purchase would contribute to the system emergency.

20. The Commission is without sufficient basis, at this time, to authorize DEC and DEP's proposal to discontinue purchases from QFs during system emergencies.

STANDARDIZED CONTRACTING

21. The proposal by DEC and DEP to standardize the contract negotiation process has merit, however, the Commission is without sufficient basis, at this time, to authorize such a process.

DISCUSSION AND CONCLUSIONS

COMPETITIVE PROCUREMENT PROCESS
FINDING NO. 1

In effort to reform the Commission's implementation of PURPA and to transition to a more "well-planned and coordinated" process, DEC and DEP propose:

> A stakeholder-developed competitive solicitation procurement model for utility-scale renewable resources that would better align deployment with the Companies' IRP and potential future REPS compliance needs, as well as overcome the operational limitations imposed by PURPA on managing QF resources.

Tr. vol. 2, p. 426, 365. DEC and DEP assert that such a process would "lower costs for customers, provide significant operational controls to [DEC and DEP], and open a new market for solar facilities outside of PURPA." Tr. vol. 2, p. 426.

It is NCSEA's position that:

> [A] transition to a competitive procurement process could be a reasonable approach to continued solar development in North Carolina, as long as the competitive procurement process: i) obligates the Utilities to procure a specific amount of capacity on an annual basis for a minimum number of years; ii) is administered by an independent evaluator selected and monitored by the Commission; iii) limits participation in the development process by the Utilities and by unqualified developers; and iv) involves a standard contract with general terms and conditions that are commercially reasonable and that afford reasonable opportunities to attract capital. NCSEA's support for a competitive procurement process is predicated on: i) the expectation that the process would be developed in a collaborative stakeholder proceeding; and ii) the existence of a continued opportunity to interconnect small QFs and sell to the Utilities outside of the [competitive procurement] process.

Tr. vol. 7, p. 381. Thus, NCSEA supports a competitive procurement process to transition away from the standard offer previously available in North Carolina as long as the Commission retains control to ensure a fair, objective and transparent process that provides a meaningful opportunity to develop QFs and results in the continued growth and maturation of the renewable energy industry in North Carolina.

The Public Staff takes the position that market-based approaches are cost-effective means of meeting the needs of their customers and generally appears to support a competitive procurement process so long as it is "appropriately structured and an independent evaluator is utilized." Tr. vol. 8, p. 63. The Public Staff notes that it has previously recommended that the Commission require the use of competitive bidding to a greater degree and, in doing so, incorporate the best practices for competitive bidding that have been identified by the National Association of Regulatory Utility Commissioners, which include: 1) that the process be fair and objective; 2) that procurement be designed to encourage robust competitive offerings; 3) that winning bids are selected based on an evaluation of relevant price and non-price factors; 4) that procurement is conducted in an efficient and timely manner; and 5) that regulators align their own procedures and actions to support the development of a competitive response. Tr. vol. 8, p. 63 - 64. The Public Staff recommends that, were the Commission to convene a formal proceeding in a new docket for the purpose of establishing a Commission-approved competitive procurement process, the Commission should consider the NARUC guidance in addition to considering the needs of the utilities as identified in their IRPs and the value offered by all types of renewable energy resources.

However, the Commission agrees with the parties that a competitive procurement process is a reasonable means for assuring the cost-effective procurement of renewable energy and capacity that in addition, if appropriately structure and fairly implemented, will provide an opportunity for the continued development of QFs in North Carolina.

By separate order, the Commission shall initiate a new, separate proceeding for the development of a Commission-approved stakeholder-developed competitive solicitation procurement program for utility-scale renewable resources.

STANDARD OFFER
FINDING NOS. 2-5

DEC, DEP and DNCP propose to reduce the threshold at which a QF qualifies for the Standard Offer from that the Commission reduce the capacity threshold for eligibility for the standard offer from 5 MW to 1 MW. Tr. vol. 2, p. 338; vol. 5, p. 143-44.

DEC, DEP and DNCP also propose to reduce the maximum term of the Standard Offer from 15 years to 10 years. Tr. vol. 2, p. 338; vol. 5, p. 143-44.

NCSEA takes the position that, until such time as there is a Commission-approved competitive procurement process under way for the electric utility, the threshold at which a QF qualifies for the Standard Offer must remain at 5 MW and the maximum term must remain at 15 years. Tr. vol. 7, pp. 380-381. NCSEA witness Harkrader testified as to the difficulties associated with negotiating a PPA with the electric utilities, including that the utilities accept few, if any, revisions to the PPA. In addition, Harkrader testified that, in negotiating a PPA, the utility retains the right to change key terms and conditions. She testified that the length of the PPA term is an example of such a key term. Thus, it is NCSEA's position that, given that an electric utility retains discretion when negotiating PPAs to set key terms that bear directly on whether a QF has a reasonable opportunity to attract capital from potential investors, maintaining the eligibility threshold for the Standard Offer at 5MW results in fewer QFs having to negotiate PPAs.

NCSEA also opposes a reduction in maximum term on the basis that a reduction in the maximum term of the Standard Offer from 15 years to 10 years will significantly reduce the pool of debt and equity investors willing to invest in a QF. Tr. vol. 7, p. 378. NCSEA witness Harkrader testified that her "personal experience is that QFs with a shorter contract term than 15 years would have a much smaller pool of potential debt and equity investors." Tr. vol. 7, p. 378. She testified that, in her experience, the "15-year contract term has allowed small QFs to access affordable debt and equity capital" and that "the 15-year contract term has enabled a capital structure that is affordable to the QF developer and, therefore, has encouraged QF development." Tr. vol. 7, p. 378. She also testified that the 5-MW, 15-year Standard Offer has been central to driving down the costs of constructing solar QFs and to growing a robust industry in North Carolina, specifically pointing out that:

> [T]he Standard Offer, particularly the PPA term and fixed rate, has provided the certainty that has been necessary to encourage QF development in recent years, and this certainty has also played a critical role in driving down the cost of developing solar facilities. When CSE first started developing solar QFs in North Carolina, the market was relatively unsophisticated with respect to the development process, as well as the financing process. The gains that have been made by industry in recent years have helped drive down the cost of solar development in North Carolina. These include: understanding and taking advantage of economies of scale with equipment suppliers; the creation and development of local supply chains and associated service providers related to solar racking, fencing, and landscaping; and the creation of a large, skilled local labor pool trained in installation and construction of solar farms. Additionally, the development of the industry has attracted suppliers, such as Schletter Inc. – a manufacturer of solar mounting systems – to relocate in North Carolina, further driving down costs. The Utilities' proposed modifications to the implementation of PURPA would

> disrupt this success and would dramatically alter the landscape of companies that participate in QF development in North Carolina and beyond.

Tr. vol. 7, p. 379.

Like NCSEA, CCR takes the position that the reduction in eligibility threshold and maximum term of the Standard Offer will have a chilling effect on the development of small QFs. Tr. vol. 6, p. 115. In support of its position, CCR offered the testimony of Patrick McConnell, a Managing Director, in charge of project finance for CCR. CCR witness McConnell's primary responsibilities include sourcing construction and permanent capital for solar project portfolios, then leading the transaction executions with CCR's capital partners. Tr. vol. 6, p. 113.

On the issue of reduction of the eligibility threshold, CCR witness McConnell testified that, given the complicated nature of QF finance, scale of the QF is critical to attracting debt and equity on reasonable terms. He testified that reducing the eligibility threshold to one (1) MW would make financing QFs in North Carolina much more challenging. He further testified that the only way to make most financings work with a five (5) MW threshold was to group them into portfolios to create critical mass for investors. A (1) MW threshold would likely shut out the institutional market from financing Standard Offer QFs as the diligence required to create a critical mass for investors would become cost prohibitive. Tr. vol. 6, p. 117.

CCR witness McConnell also presented extensive testimony on the impact of the reduction of PPA term on the ability of the QF to attract capital. He testified that outside of outright project sales and sale leaseback transactions, every financing transaction CCR closes involves both permanent debt and tax equity investors. Tr. vol. 6, p. 113. For CCR, typical investors of both debt and tax equity include large banks, insurance companies, and public corporations. Tr. vol. 6, p. 113. With respect to financing of QFs in North Carolina, McConnell testified that like most other solar developers, CCR employs a combination of sponsor equity (internal capital), construction loans, permanent loans, and tax equity to finance the construction and operation of all of its QFs in North Carolina. Tr. vol. 6, p. 113. McConnell testified that, in addition to the rate offered to the QF, the creditworthiness of the purchasing utility and the term of the PPA are the most critical components of the financing. Tr. vol. 6, p. 114.

With respect to the significance of PPA term to the financing process, CCR witness McConnell testified that under typical circumstances when evaluating the economics of a QF, an investor will not consider revenue beyond the term of the PPA and, without reasonable certainty as to contracted revenue based on a defined PPA term at a defined price, investors are generally unwilling to bet on a utility's future avoided cost. Tr. vol. 6, p. 114. To this end, McConnell testified that had had yet to see a loan maturity or amortization for a QF smaller than 75 MW extend beyond the term of the PPA. Tr. vol. 6, p. 114. Further, McConnell testified that the cash flow profiles for QFs with PPAs of less than 15 years, and in most cases 20 years, simply do not make economic sense for smaller QFs. Tr. vol. 6, pp. 114-115. McConnell further testified that the general rule that lenders are unwilling to lend against uncontracted revenue is especially true for smaller QFs (below about 50 MW), which are of insufficient scale to attract larger, more sophisticated investors who may be willing to accept a few years of merchant avoided cost exposure if certain underwriting protections are in place. Tr. vol. 6, p. 115. Additionally, on the issue of the economies of scale for a large QF versus a small QF, McConnell explained that lager QFs involve marginally lower construction costs and that larger QFs result in the amortization of fixed financing costs over a larger project. Tr. vol. 6, p. 124.

Finally, CCR witness McConnell testified that reducing the PPA term of the Standard Offer to 10 years would have a two-fold impact. First, it will reduce the amount of debt available to finance the QF, thereby increasing the amount of equity required and reducing the rate of return on that the QF is able to provide for that equity. Second, due to a larger percentage of the QF's revenue being uncontracted (i.e., beyond the term of the PPA) and, therefore, inherently riskier, the rate of return required to attract equity investment would be significantly higher. These two dynamics in conjunction would make it significantly more difficult if not impossible to attract the required level of equity investment for a small QF. Tr. vol. 6, pp. 115-116. McConnell opines that this, in turn, will result in many fewer small QFs getting financed and constructed. Tr. vol. 6, p. 115.

In addition to the testimonies of NCSEA witness Harkrader and CCR witness McConnell on the issue of reduction in PPA term, NCSEA offered the testimony of Kurt Strunk, a Director of National Economic Research Associates, Inc., a firm of economists that specialize in matters related to the electric power sector. NCSEA witness Strunk has more than twenty years of professional experience working as an economist in the power sector, and his practice at NERA focuses on financial matters of energy firms. Tr. vol. 6, pp. 12-13.

NCSEA witness Strunk concludes that reducing the maximum term of the Standard Offer will deprive QFs of a reasonable opportunity to attract capital because it will compress the recovery of capital investment in long-lived generation assets into too short a period. Tr. vol. 6, p. 17. Specifically, Strunk explains that traditionally regulated states like North Carolina, the business model for independent power producers (IPPs) (QFs are a subset of IPPs) depends on forward looking contracting. Strunk explains that IPPs typically must obtain long-term contracts to secure financing and to ensure that they are not subject to "holdup" which, in this context, is the opportunistic behavior by the utility after the investment has been made and the IPP no longer has negotiating leverage because there are no practical alternative buyers of its output. Fixed pricing committed for long terms – sufficient to provide a reasonable amortization of sunk investment costs for a long-lived asset – has traditionally underpinned the financing of new IPPs. Tr. vol. 6, pp. 18-19.

NCSEA witness Strunk explains further that there is no bright line differentiating a financeable project from a non-financeable one; rather the ability to secure reasonable quantities of debt financing tends to hinge on factors such as the amount of equity committed, the interest rates paid, payback periods and other terms required by lenders, as well as the lenders' perceptions of risk in extending credit to the project. Tr. vol. 6, p. 19.

NCSEA witness Strunk makes the points that reducing the PPA term increases the near-term costs for the QF due to increased costs of debt and equity, decreases the possibility that those costs could be recovered at the avoided cost pricing, and reduces the likelihood that the QF will be developed. Tr. vol. 6, p. 20.

NCSEA witness Strunk also testifies that, while it is true that equity investors may count on a certain amount of residual value after the PPA term, they may not be willing to accept a large share of unrecovered capital post-PPA term, and forcing too much capital recovery into the post-PPA period will undermine the attractiveness of the investment to equity investors. Tr. vol. 6, p. 21.

With respect to whether a QF could solve the issues presented by reduced PPA term through the contribution of additional equity, NCSEA witness Strunk explains that, in principle, the QF developer could contribute more equity or even the entirety of funds necessary to construct the QF. Tr. vol. 6, p. 22. In practice, however, this is unlikely. Equity investors are often capital constrained and seek to employ debt leverage as part of attractive financial structures and to offer lower prices. Tr. vol. 6, p. 22.

NCSEA witness Strunk explains that his analysis is not limited to solar QFs and that while each type of generating technology has its own economics, the principles outlined are general and not specific to a given type of generating technology. Tr. vol. 6, p. 25.

The Public Staff takes the position that it is appropriate for the Commission to consider modifications to the Standard Offer. Tr. vol. 8, p. 57. Specifically, the Public Staff recommends that the Commission reduce the Standard Offer threshold from five (5) MW to a level that "reflects current conditions in the QF marketplace and better protects ratepayers from the risk of overpayment." Tr. vol. 8, p. 57. The Public Staff notes support for reducing the threshold to two (2) MW or one (1) MW. Tr. vol. 8, p. 60.

Recognizing that a reduction in threshold will increase the number of QFs that must negotiate a PPA with the purchasing electric utility, the Public Staff notes that its investigation revealed that the process of negotiating PPAs can still be challenging to QFs, even though utilities and large QFs are entering PPAs. Tr. vol.

8, p. 61. In addition, the Public Staff points out that, with respect to the QFs for which non-standard PPAs have been executed, many “are significantly larger in size than the current standard offer threshold, indicating that QFs have sought to maximize economies of scale and available interconnection capacity in a more efficient way.” Tr. vol. 8, p. 61. The Public Staff also “recognizes that the unpredictability and often protracted nature of negotiating PPAs, along with the delays in the interconnection process, may place QFs in a difficult position with regard to their ability to secure project financing in a timely fashion and may also raise transaction costs. While QFs maintain the right to petition for arbitration before the Commission, this process is also time consuming and adds significant transaction costs.” Tr. vol. 8, pp. 61-62.

The Public Staff cautions that the Commission must streamline and improve the process to reduce transaction costs and provide a level playing field for QFs trying to negotiate PPAs, should the Commission reduce the eligibility threshold for the Standard Offer. Tr. vol. 8, p. 61.

With respect to the maximum term of the PPA, the Public Staff supports a reduction from 15 years to 10 years. Tr. vol. 8, p. 73. However, the Public Staff points out that: 1) the use of 15-year fixed term contracts appears to have been accepted by the financing community and has been beneficial to encouraging QF development in North Carolina, given the number of currently operating facilities and solar projects in development; and 2) in its examination of other the implementation of PURPA states, no trend regarding length of term emerged, as some, in some states, a longer term is offered and in some states a shorter term is offered. Tr. vol. 8, p. 69.

With respect to the risk of overpayment, the Public Staff notes that avoided costs change considerably over time, and there is always a risk of overpayment or underpayment of avoided costs. Tr. vol. 8, p. 69. The Public Staff noted that, while avoided costs have declined over the past two biennia, avoided costs could begin to rise (for example, due to an unanticipated rise in natural gas prices), which would result in contracts that were signed at lower forecasted avoided cost rates becoming increasingly favorable for ratepayers over the long-term. Tr. vol. 8, p. 70.

The Public Staff emphasizes the risks inherent to forecasting, making the point that over time, actual prices may deviate from the forecasted prices, sometimes benefitting ratepayers. The Public Staff notes that, similar to a QF contract, a utility's commitment to build a generating facility represents a long-term fixed obligation for the utility's customers, based largely upon forecasts of future prices. Tr. vol. 8, p. 70. The Public Staff notes that the utility’s self-build generation is justified using similar forecasting as is used in the avoided cost proceeding and, thus, is similarly uncertain. Tr. vol. 8, p. 71. The Public Staff illustrates this point by considering two utility investments in new generating facilities. First, DEC's Cliffside Unit 6 was originally proposed to operate as a baseload unit in 2006, but, due to changes in coal prices relative to natural gas, has ultimately operated more as an intermediate unit. Second, DEP's decision to build its natural gas-fired Richmond County Combined Cycle facility in 2008 proved to be advantageous to ratepayers due to the decline in natural gas prices, and the facility has operated more as a baseload plant than as an intermediate facility as originally planned and modeled by DEP, saving customers millions of dollars in fuel costs.

Finally, in support of its recommendation to reduce the maximum term to 10 years, the Public Staff points out that its investigation revealed that DEC, DEP and DNCP have entered into negotiated PPAs with 10-year terms.

As the Commission has recognized in recent orders, the FERC has ruled that QFs have a right to fixed long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred. While the FERC has never specified a minimum or maximum term to be offered by utilities to QFs, the FERC has recently declared that PPAs must be “long enough to allow QFs reasonable opportunities to attract capital from potential investors.” In re. Windham Solar LLC & Allco Fin. Ltd., Notice of Intent Not To Act And Declaratory Order, 157 FERC ¶ 61,134, November 22, 2016, paragraph 8.

As it has done in past proceedings, in considering whether to reduce the term, the Commission has endeavored to ensure that ratepayers are not exposed to undue risk of overpayments while, at the same time, QFs are provided with reasonable opportunities to attract capital from potential investors.

The Commission notes that Public Staff witness Hinton could not recall the nameplate capacities of the solar QFs that have entered into 10-year PPAs with DEC, DEP or DNCP. The Commission will assume that those QFs are in excess of 5 MW since they negotiated PPAs with the utility. The Commission notes also that Public Staff witness Hinton testified that a reduction in PPA term, coupled with the utilities’ proposals to modify the avoided cost calculations, would have an additive effect on challenging a QF’s ability to attract capital. Tr. vol. 8, p. 231. Thus, the Commission is concerned that the ability to attract capital at a 10-year term has been limited to large solar QFs and that reducing the maximum term to 10 years, in combination with other changes sought by DEC, DEP and DNCP, will have an additive effect on small QFs.

The Commission notes that NCSEA witness Harkrader testified that 15-year contract term has allowed small QFs to access affordable debt and equity capital and has played a significant role in the development of the solar industry in North Carolina. In addition, the Commission notes that both CCR witness McConnell and NCSEA witness Harkrader testified that, in their experience, the pool of investors for a QF with a 10-year PPA is small and that this reality would be exacerbated in the context of small QFs that cannot achieve the same economies of scale that larger QFs can achieve.

The Commission is persuaded by CCR witness McConnell that reducing the PPA term of the Standard Offer to 10 years would have a two-fold impact. First, it will reduce the amount of debt available to finance the QF, thereby increasing the amount of equity required and reducing the rate of return on that the QF is able to provide for that equity. Second, due to a larger percentage of the QF's revenue being uncontracted (i.e., beyond the term of the PPA) and, therefore, inherently riskier, the rate of return required to attract equity investment would be significantly higher. The Commission recognizes that these two dynamics in conjunction will make it significantly more difficult if not impossible to attract the required level of equity investment for a small QF and that many fewer small QFs would be financed and constructed.

The Commission also takes note of the points made by NCSEA witness Strunk, specifically that reducing the PPA term increases the near-term costs for the QF due to increased costs of debt and equity, decreases the possibility that those costs could be recovered at the avoided cost pricing, and reduces the likelihood that the QF will be developed. The Commission agrees with NCSEA witness Strunk's analysis of whether a QF could solve the issues presented by reduced PPA term through the contribution of additional equity. The Commission is persuaded by NCSEA witness Strunk's explanation that while, in principle, the QF developer could contribute more equity or even the entirety of funds necessary to construct the QF, in practice, this is unlikely as investors are often capital constrained and seek to employ debt leverage as part of attractive financial structures and to offer lower prices.

The Commission also takes note of the fact that NCSEA witness Strunk's analysis is not limited to solar QFs but is applicable to any type of QF. While the DEC, DEP and DNCP have presented evidence of the declining costs of solar, no party has presented evidence on the costs of non-solar QFs. Thus, the Commission assumes that non-solar QFs would be disproportionally impacted by a reduction in maximum term.

After weighing the evidence presented, at this time, a reduction in the eligibility threshold for the Standard Offer is not warranted as such a reduction would likely have a chilling effect on the development of small QFs in North Carolina. However, at such time as a Commission approved competitive solicitation is underway for the electric utility, the Standard Offer eligibility threshold for that electric utility shall be reduced to one (1) MW.

In addition, the Commission is persuaded that the elimination of a 15-year maximum term for small QFs, particularly in combination with other changes proposed by DEC, DEP and DNCP, will result in a barrier to allowing the reasonable opportunities to attract capital from potential investors. Therefore, the Commission concludes that the maximum term for the Standard Offer shall remain at 15 years as a shorter term will deprive QFs of reasonable opportunities to attract capital from potential investors.

PEAKER METHODOLOGY
FINDING NOS. 6-9

Ascribing Zero Avoided Capacity Value

DEC and DEP propose to ascribe avoided capacity value to a QF only in those years in which the electric utility's Integrated Resource Plan (IRP) shows a need.

DNCP proposes to ascribe no avoided capacity value to the QF. Tr. vol. 5, p. 198. Alternatively, DNCP proposes to accept the proposal of DEC and DEP of ascribing avoided capacity value to QFs only in those years in which the electric utility's IRP shows a need.

NCSEA takes the position that the Commission should reject these proposals. Tr. vol. 7, p. 293. NCSEA witness Johnson testifies that DNCP's proposal results in the payment of no avoided capacity rate and that the DEC and DEP proposal results in an approximate 60% reduction in the avoided capacity rate from the 2014 rate. Tr. vol. 7, pp. 289-290.

In support of NCSEA's position, NCSEA witness Johnson testifies that the Commission rejected this same proposal by DEC and DEP in the 2014 biennial avoided cost proceeding. Johnson points out that: 1) DEC and DEP justified their proposal in 2014 on the same or similar bases on which they justify the 2016 proposal; and 2) that the Commission should reject the proposal again, as it did in 2014. Tr. vol. 7, pp. 290-293.

In addition, NCSEA witness Johnson testifies that the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of "incremental cost" and "avoided cost." Tr. vol. 7, p. 293. He also testifies that the use of zeros is inconsistent with the concept of "ratepayer indifference," and it leads to undue discrimination against QFs. Tr. vol. 7, p. 293.

NCSEA witness Johnson testifies that, in general, the goals of PURPA are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. More specifically, QF avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added. Tr. vol. 7, p. 294. He testifies that because of economies of scale, electric utilities typically find it cost effective to construct large generating facilities, at multi-year intervals. He explains that if the utility has a capacity need of 100 MW per year over a 6-year period, it will not add a 100 MW plant every year but instead will add a 600+ MW plant in a single year. Under these circumstances, Johnson opines, economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others. Tr. vol. 7, p. 295. Put a different way, Johnson explains that given reality of how electric utilities add new generating capacity, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled to be placed into service. Tr. vol. 7, p. 295.

With respect to discrimination against QFs, NCSEA witness Johnson testifies that PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers." He explains that under rate base regulation, the utilities are allowed to recover the cost of new generating capacity as they are completed and put into commercial operation, even though some of the capacity is being added prior to the time it is required (due to lumpiness). He testifies that since the utility is allowed to recover its capacity costs during the "zero" years just after a new capacity addition and its reserve margin is higher than the required minimum, to avoid discrimination, the QF should be treated the same. Tr. vol. 7, p. 296.

The Public Staff disagrees with DNCP's proposal to ascribe no avoided capacity value to the QF and offer no avoided capacity rate. Public Staff witness Hinton testifies that DNCP's proposal to assign no capacity value to future QF generation because there is more generation in DNCP's North Carolina service territory than load seems to run counter to general principles of utility system planning. Tr. vol. 8, p. 34. He testifies that utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis. Tr. vol. 8, p. 34. He points out that DNCP's membership in PJM makes it a part of a vast integrated transmission system with interfaces with PJM-E, PJM-W, and AEP with greater access to generation resources, load diversity, and improved reserve sharing across the region. He also testifies that DNCP's 2016 IRP indicates a long-term capacity need of approximately 4,457 MWs. He concludes that DNCP's position that there is no capacity value associated with incremental QF generation is unreasonable. Tr. vol. 8, p. 35.

The Public Staff supports the proposal by DEC and DEP to limit capacity payments until the IRP dictates a capacity need. However, the Public Staff notes that changing economic and regulatory conditions may lend to reconsideration of this issue in future proceedings. Tr. vol. 8, p. 30. Public Staff witness Hinton points out that according to the theory of the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a combustion turbine, or CT) plus the marginal costs of running the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Tr. vol. 8, p. 26. While Hinton generally agrees with the use of the peaker method, he points out that, in reality no utility system operates at optimality. He notes that a utility may have more than or less than the optimal level of capacity at any given time but that, except in the case of a severe deviation, minor deviations smooth out over time. Tr. vol. 8, pp. 26-27.

Significantly, Public Staff witness Hinton testifies that the level of QF generation existing in the service territories of DEC, DEP and DNCP has not resulted in a severe deviation from optimality at this time. He testifies that if a substantial number of the solar facilities in the interconnection queues noted by DEC, DEP and DNCP are developed, then "there is a growing likelihood of severe and persistent deviation from optimality." Tr. vol. 8, pp. 27. He testifies that "an additional 4,900MWs from new QFs represents unchartered waters in DEC's and DEP's planning." Tr. vol. 8, p. 28.

After consideration of the evidence in the record, the Commission concludes that the proposals by DEC, DEP and DNCP to ascribe no or limited avoided capacity value to the QF are fundamentally inconsistent with the peaker method and is, therefore, not appropriate as long as the peaker method is used to calculate avoided costs.

As the Commission has previously concluded, it should not authorize as a generic principle that the avoided cost rate should be reduced as advocated when the utility shows no need to acquire capacity certain years of the term of the QF PPA. Order Setting Parameters, p. 35.

Additionally, when addressing the DNCP proposal to include zeros in the calculation of avoided capacity cost during the first three years of the contract term, in the 2014 biennial avoided cost proceeding, the Commission expressed the following:

> The Commission is concerned that including zeroes for the first three years in the calculation of capacity rates lowers the avoided cost rate for the entire 15-year period. Thus, depending on the utility's actual needs over the term of the PPA, the resulting avoided cost rates may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. The most recent IRPs for DEC, DEP and DNCP show they need to build or buy over 3,000 MW of capacity over the next 15 years. As conceded by DNCP's witnesses on cross-examination, the cost of that future needed capacity is not changed by the fact that a utility has sufficient capacity in the very near term.

Order Setting Parameters, p. 35. Further, the Commission previously concluded that "while DNCP may not project a need in its first three years due to its participation in the market, it would also be true that the final three years of a QFs long term contract could cover a future need, and, thus, be of more value than the avoided cost rate reflects." Order Setting Parameters, p. 35.

The Commission also found to be significant, in the 2014 biennial avoided cost proceeding, the fact that the utilities typically are not penalized for having capacity that results in a reserve margin at or above the upper range of what is optimal than they need for the first few years after a large generating unit is placed in rate base. This is in spite of the fact that their ratepayers may be paying a return on most of the investment in the plant for the initial years. Order Setting Parameters, p. 35.

In the Order Setting Parameters, the Commission concluded that if:

> poor economic conditions, combined with a large influx of QFs, eliminated all future need for utility fossil generation capacity, there would be no future capacity to offset or avoid. The Commission agrees that, under those circumstances, the payment of avoided capacity could be inconsistent with PURPA. That may not be the circumstances in which the utilities find themselves, however. Presently, each of the three shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid.

Order Setting Parameters, p. 36.

The Commission takes note of the fact that, since 2012, significant solar QF capacity has been installed in the DEC, DEP and DNCP service territories in North Carolina. However, similar to the circumstances that existed at the time of the 2014 biennial avoided cost proceeding, the IRPs of DEC, DEP and DNCP show the need for thousands of MW of generation over the planning horizon. Specifically, DEC's 2016 IRP indicates a capacity need of 3,903 MW over the planning period; DEP's 2016 IRP indicates a capacity need of 4,071 MW over the planning period. Tr. vol. 8, pp. 30-31. DNCP's 2016 IRP indicates a capacity need of 4,457 MW of capacity over the planning period. Tr. vol. 8, p. 35. Thus, as was the case in 2014, DEC, DEP and DNCP shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid. In fact, specifically with respect to DEC, Public Staff witness Hinton, on cross examination, pointed out that lower growth rates and peak demands, in combination with anticipated solar QF capacity addition, eliminates or reduces the need for 435 MW of CT capacity. Tr. vol. 8, pp. 232-233.

The Commission is persuaded by the testimony of NCSEA witness Johnson that, in general, the goals of PURPA are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. Further, the Commission determines that the avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added. The Commission is persuaded by NCSEA witness Johnson's testimony that economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others. The Commission agrees with NCSEA witness Johnson that, given reality of how electric utilities add new generating capacity, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled to be placed into service.

The Commission has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Order Setting Parameters, p. 30. The Public Staff supports the DEC and DEP proposal due to a deviation from optimality. However, Public Staff witness Hinton testifies that any deviation that may exist presently is not severe. Tr. vol. 8, p. 27. Further, the Public Staff's concern appears to be founded in the assumption that a substantial percentage interconnection queues will actually be developed. Again, while the Commission recognizes that North Carolina has experienced significant growth in solar generating capacity over the past several years, proposed QFs—for which CPCNs have been issued or for which interconnection requests have been submitted—does not equate to development that will come online. In fact, on cross examination a DEC/DEP witness acknowledged that the all of the 4,900 MW in the combined DEC and DEP interconnection queues will not be constructed. Tr. vol. 3, pp. 10-12.

Additionally, even if the Commission were inclined to adopt the proposals of DEC, DEP and DNCP—which it is not—the Commission has concerns about relying on the capacity needs identified in the IRP to ascribe avoided capacity value to QFs. As DEC/DEP witness Snider testified on cross-examination, neither the Lincoln County CT nor the generation capacity additions associated with the Western Carolinas Modernization project were included in the IRPs prior to the utility's filing applications for certificates of public convenience and necessity to construct these facilities. Tr. vol. 3, pp. 68-69. These instances illustrate capacity additions made, or sought to be made, outside of the IRP and suggest that, relying on the capacity needs as they are identified in the IRP, may result in understatement of avoided capacity cost.

Finally, as a practical matter, historically, the biennial avoided cost filings are made before a final order is issued approving the IRP. Tr. vol. 8, p. 229. Thus, question arises as to which IRP the utility should use for the purpose of calculating its rates. It seems that using the previously approved IRP gives rise to a potential inaccuracy claim when the avoided costs are calculated for the biennial proceedings, as the expansion plans may change from year to year.

Thus, as the Commission held in the 2014 biennial avoided cost proceeding, it does not authorize as a generic principle that the avoided capacity cost should be reduced to account for those years when the utility's IRP shows no need to acquire capacity. Therefore, the Commission directs DEC, DEP and DNCP to recalculate the avoided capacity rates to reflect an avoided capacity value during each year of the PPA term, regardless of whether the IRP shows a capacity need in a particular year.

Consistency Between Large and Small QFs

In the Order Setting Parameters, the Commission recognized that the method by which avoided costs are calculated should remain consistent in both standard and negotiated contracts and that if a method is not applicable to calculating the avoided costs of a "small" QF, the fact that a QF is a "large" QF does not validate such a method. In the Order of Clarification, N.C.U.C. Docket E-100, Sub 140, May 6, 2015, the Commission provided additional guidance on the issue of what is appropriate in the context of an electric utility's negotiations with a QF not eligible for the Standard Offer. In the Order of Clarification, the Commission made clear that: 1) the Standard Offer is not available to large QFs but is available only to those QFs that fall within the capacity eligibility threshold; 2) an electric utility is not required to offer the same terms to all QFs not eligible for the Standard Offer; and 3) an electric utility is required to use current avoided cost data in calculating the rates offered to the QF. The Commission emphasized that "proper application of the peaker method does not change or depend on the capacity of the QF. On the other hand, individual QF characteristics, such as capacity, location, etc., may appropriately be the basis for differences in terms and inputs in separately negotiated contracts." The Commission further explained that, in the course of negotiation, either party may identify specific characteristics of a particular QF that merit consideration in the calculation of the avoided cost rates.

In the interest of additional clarification, the Commission again determines that the proper application of the peaker methodology does not change or depend on the capacity of the QF. The parties may negotiate over characteristic specific to the QF that bear on the inputs to the peaker method, but fairness and the objective of avoiding unnecessary litigation dictate that the peaker method must remain consistent across large and small QFs.

DNCP witnesses appear to confirm that DNCP's understanding that application of the methodology must be consistent between large and small QFs and that DNCP does not intend to apply the peaker method differently for QFs not eligible for the Standard Offer. Tr. vol. 6, p. 39. DNCP proposes to take into account the locational value of QFs when calculating rates. This proposal appears to be consistent with the Commission's Order of Clarification, though, as NCSEA points out, additional information and analysis is necessary for the Commission and interested parties to understand the merits of DNCP's calculations. Tr. vol. 7, p. 288.

DEC and DEP appear to propose to adjust rates offered to large QFs based on integration costs and ancillary service costs. Tr. vol. 3, p. 73. As DEC and DEP have offered no testimony or evidence on: 1) the nature of such costs; 2) how such costs will be calculated; and 3) whether such costs will be based on specific characteristics of individual QFs. As such, the Commission is concerned that such proposal goes beyond the Order of Clarification; therefore, at this time, such adjustments shall not be made to rates offered to QFs.

Impact Beyond Avoided Cost Proceeding

The avoided cost calculation methodology established in this proceeding impacts utility programs other than those related to their PURPA obligation. In making the foregoing decisions, the Commission is cognizant of the fact that, as testified by Public Staff witness Hinton, avoided costs provide the basis for: i) rates paid for purchases from QFs; ii) including the determination of the cost effectiveness of DSM/EE programs; iii) the calculation of performance incentives for such programs; and iv) the determination of the incremental cost of compliance with the North Carolina Renewable Energy Portfolio Standard. Tr. vol. 8, p. 21. Thus, decisions made in this proceeding impact far more than the electric utility's PURPA obligations. For this reason, the Commission concludes that significantly revising the peaker methodology from that which has historically been applied in North Carolina, as the Utilities would have us do, is not prudent, given the other applications in which the methodology is critical.

AVOIDED ENERGY COSTS AND RATES
FINDING NOS. 10-14

Fuel Forecasts

In constructing their fuel forecasts, DEC and DEP used fuel price data from futures markets for the first 10 years (through 2026), followed by a four-year transition to a fundamental forecast. Beginning in 2031 it exclusively used its Fall 2016 fundamental forecast assuming Clean Power Plan compliance. Tr. vol. 7, p. 242.

On average, DEC and DEP have reduced their predicted natural gas prices by approximately 14% and their predicted coal prices by approximately 13% from those in the 2014 biennial avoided cost proceeding. Tr. vol. 8, p. 46.

In contrast to DEC and DEP, DNCP relied on 18 months of forward market data, followed by 18 months of a blend of the market prices and the ICF commodity price forecast as of early October 2016, followed by ICF's commodity price forecast for the remaining years. Tr. vol. 8, p. 48.

DNCP's forecasted natural gas and coal prices declined by approximately 8% and approximately 23%, respectively, from its price forecasts in the 2014 biennial avoided cost proceeding. Tr. vol. 8, p. 46.

NCSEA takes the position that DEC's and DEP's overreliance on forward market data is not reasonable. Tr. vol. 7, p. 249. Additionally, NCSEA takes the position that DNCP used unreasonably low fuel prices in constructing its fuel forecast for this proceeding, as compared to the fuel prices used in its 2016 IRP forecast.

In support of its position, NCSEA witness Johnson testified that Duke Energy Corporation goes to considerable effort and expense to develop its own, comprehensive fundamental forecast of the entire US energy sector, which it updates periodically for use by both the parent and its subsidiaries. This proprietary forecast reflects Duke Energy Corporation's view of the long-term outlook for the energy sector, which it uses to make long-term investment decisions by all of its electric utilities. Tr. vol. 7, p. 245, 249.

NCSEA witness Johnson testified that forward market data is useful for short term forecasts, because it can easily and frequently be updated, as commodities traders respond to changes in the weather and minute-by-minute and day-to-day changes in supply and demand conditions in the commodities markets. In essence, forward market data is particularly useful for dealing with, and hedging against, fluctuations in commodity prices over the near-term future. But, it is not as useful, nor as appropriate, to use it for long-term planning purposes. Tr. vol. 7, p. 249.

Further, NCSEA witness Johnson testified that Duke Energy Corporation goes to great effort to develop and periodically update its fundamental forecast of energy prices, which it uses for many different long-term planning purposes. In Johnson's opinion both Duke Energy Corporation's fundamental forecast, as well as the forecast DNCP used in its 2016 IRP, seem reasonable, and both are reasonably consistent with the most recent long term fundamental forecast of natural gas prices that was published in March 2017 by EIA. Tr. vol. 7, pp. 254-255.

NCSEA witness Johnson testifies that it would be reasonable for the Commission to rely on the 2017 EIA forecast—a publicly available fundamental forecast—as a benchmark for judging the reasonableness of the fuel forecasts that DEC, DEP and DNCP use to calculate avoided energy costs. Additionally, Johnson testifies that it would be reasonable for the Commission to require DNCP to use either the 2017 EIA forecast or the fundamental forecast it used in preparing its 2016 IRP. Tr. vol. 7, pp. 255-256.

NCSEA witness Johnson also recommends that the Commission again reject the use of forward market data for anything more than the near-term future and direct DEC and DEP to reconstruct their fuel forecasts using a blend of forward market data and fundamentals data. Tr. vol. 7, p. 256.

Similarly, the Public Staff has concerns with DEC's and DEP's use of 10-year forward prices to develop forecasts for natural gas. Tr. vol. 8, p. 47.

Public Staff witness Hinton testified that in both the 2014 biennial avoided cost proceeding and the 2016 IRP proceeding, the Public Staff expressed concerns with DEP's and DEC's over-reliance on long-term forward prices for their fuel forecasts. Hinton points out that in their 2014 IRPs, DEC and DEP incorporated five years or less of forward price data before transitioning to a long-term fundamental natural gas price forecast. Hinton testifies that DEC and DEP made changes to this approach in their 2015 IRP updates by extending the period on which forward price data were relied to ten years. Tr. vol. 8, p. 47.

Public Staff witness Hinton also points out that in the 2014 biennial avoided cost proceeding, the Public Staff and other parties recommended to the Commission that the DEC and DEP return to their previous use of forward prices for no more than five years of the forecast before transitioning to a fundamental forecast. Tr. vol. 8, p. 48. Hinton testifies that in the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, issued on December 17, 2015, in N.C.U.C. Docket No. E-100, Sub 140, the Commission ordered DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts constructed in a consistent manner with those utilized in their 2014 IRPs. Tr. vol. 8, p. 48. He points out that in this proceeding, however, DEC and DEP are again proposing to use ten years of forward prices. Tr. vol. 8, p. 48.

The Commission is concerned, for the reasons expressed by NCSEA witness Johnson as well as the Public Staff, about the overreliance on forward price data by DEC and DEP.

In support of its position, the Public Staff takes the position that the use of five years of forward data is reasonable because the market for such shorter-term transactions is relatively liquid while the market for 10-year futures is relatively illiquid—meaning that the number of investors willing to buy and sell decisions on prices 10 years into the future is much smaller than the number of investors willing to do so five years into the future. Tr. vol. 8, p. 49. The Public Staff argues further that fundamental price forecasts are based on future supply and demand conditions and involve a more measured and tempered response to anticipated changes in the market. Tr. vol. 8, p. 49. Thus, for these reasons, the Public Staff determines that five years of forward data followed by the fundamental forecast data strikes the appropriate balance when constructing the fuel forecasts.

DEC and DEP take the position that long-dated forward contracts are liquid and transactable and can be purchased over the counter at large financial institutions. Tr. vol. 2, p. 253. DEC and DEP purchased a 10-year forward natural gas contract to demonstrate market liquidity. Tr. vol. 2, p. 250. However, the Commission is not persuaded that this single purchase demonstrates market liquidity and undermines the credibility of the Public Staff's position. On cross examination, DEC/DEP witness Snider acknowledged that neither utility had made a similar 10-year forward purchase prior to the purchase made for purposes of this docket. Tr. vol. 4, p. 104. Further, although Snider testified that he could repeat the transaction by making calls to multiple counterparties willing to transact, DEC and DEP offered no evidence that such calls had been made. Tr. vol. 4, p. 120. In addition, DEC and DEP did not offer the actual contract evidencing the transaction into evidence; thus, the Commission is unable to analyze whether the transaction is what DEC and DEP purport it to be. Thus, the Commission is unable to reach a conclusion as to the validity of the 10-year purchase made by DEC and DEP, and, furthermore, the Commission does not agree with the DEC and DEP position that a single transaction illustrates market liquidity. Tr. vol. 4, p. 120.

DEC and DEP also argue that the use of 10-year forward data is consistent with their last two IRPs and, therefore, the Commission's directive in the 2014 avoided cost proceeding. Tr. vol. 2, p. 255. The Commission takes note, however, that: i) (as acknowledged by DEC/DEP witness Snider on cross-examination) in accordance with Rule R8-60(l) of the Commission's Rules and Regulations, comments from intervenors were limited in the 2015 IRP update proceeding, Tr. vol. 4, p. 113; ii) both NCSEA and the Public Staff commented on this issue in the on-going 2016 biennial IRP proceeding, Tr. vol. 7, pp. 244-245; and iii) no final order has been issued in the 2016 IRP proceeding as of the date of this order.

The Commission is persuaded that the fundamental forecasts should be relied on for the purposes of the avoided energy cost calculation, as they are professionally developed by third party experts, involve a more measured and tempered response to anticipated changes in the market, and are relied upon by the utilities for long term planning purposes. The Commission recognizes that a blend of forward data with the fundament data is appropriate but, ultimately, the fundamental data must be included in the interest of mitigating forecast risk.

For the foregoing reasons, the Commission directs DEC and DEP to recalculate their avoided energy rates using no more than five years of forward natural gas prices before transitioning to their long-term fundamental price forecast.

Resetting Avoided Energy Rate

DEC and DEP propose to reset the avoided energy rates during each biennial avoided cost proceeding to mitigate the risk of over- or under-projecting long-term commodity prices. As an alternative, DEC and DEP propose to offer a fixed rate, based on two-years of forecasted avoided energy costs, over the 10 year PPA term.

NCSEA takes the position that this proposal results in disruptive uncertainty and links the future revenue stream – which is critical to the economics and financing of a QF -- to the future course of volatile fuel prices and other variables that are unknowable and unpredictable from the perspective of the QF and their investors, likely discouraging investment in QFs.

CCR takes the position financing parties would view a ten-year PPA with a two-year readjustment to the avoided energy rate no more favorably than they would a two-year contract, which would not be financeable. CCR witness McConnell testified having a fixed rate over the PPA term establishes value. Further, without fixed rates, lenders are unwilling to bet on what the avoided cost rates will be going forward. Fixed rates for a fixed over the term of the contract are critical to securing financing.

The Public Staff takes the position that this proposal is inconsistent with the QF's right to long-term fixed rates under Section 210 of PURPA and FERC precedent. The Public Staff takes the position that requiring a 2-year reset on the avoided energy rates offered in the Standard Offer would not provide sufficient "certainty with regard to return on investment" to allow a QF with a reasonable opportunity "to attract capital from potential investors."

The Commission is persuaded that DEC and DEP's proposal to reset the avoided energy rate every two years is unreasonable. First, the Commission agrees with the Public Staff that a rate that resets every two years is inconsistent with the QF's right to a fixed rate over the term of the PPA. This Commission has repeatedly recognized that a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind decisions. The FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility.

In addition, the Commission is persuaded by the testimony of CCR witness McConnell that investors would effectively view a ten-year PPA with a two-year readjustment to the avoided energy rate as a two-year contract, which would not be financeable. Thus, beyond being inconsistent with a QF's PURPA rights, the Commission is persuaded that the proposal to re-set rates would discourage QF development. For these reasons, neither the two-year resetting energy credit nor the 10-year fixed energy credit based on 2-years' of avoided cost data shall be allowed.

Adjustment for Locational Value

DNCP proposes to adjust its avoided energy rate to reflect locational value is not appropriate at this time but merits study for future consideration.

The Public Staff takes the position that DNCP's proposal is reasonable, and NCSEA takes the position that, conceptually, using LMP data to help refine rates is reasonable, as LMPs may be relevant to the problem of how best to encourage QF power to be generated where it is most valuable. However, NCSEA witness Johnson testifies that additional granularity and further refinement to DNCP's approach may be warranted before the Commission authorizes DNCP to implement this proposal, in the interest of transparency and ensuring that the method for accounting for locational value results in encouraging QFs to locate where the QF can provide value to the utility and its ratepayers.

The Commission is persuaded by the testimony of NCSEA witness Johnson that using LMP data to help refine the QF rates could be appropriate, as LMPs may be relevant to the problem of how to improve QF price signals and to encourage QF power to be generated where it is most valuable to ratepayers. The Commission agrees with NCSEA witness Johnson that additional granularity and further refinement of this approach is necessary before the Commission shall authorize DNCP to make such change. Specifically, before the Commission authorizes such an adjustment, DNCP must provide the following information: 1) if, on average, North Carolina LMPs have been consistently running about 5% below the DOM Zone average, what are the underlying factors that are causing this differential; 2) how large is the variation in LMPs observed at specific locations within DNCP's system in North Carolina; 3) does the differential at individual locations remain fairly stable, or does it fluctuate significantly over time; 4) is it appropriate to average the differential across DNCP's entire North Carolina service area, or should more granularity be retained; 5) what are the underlying factors that explain the pattern of LMP differentials; 6) to what extent do the differentials vary in response to changes in these explanatory factors; 7) does generating more QF power near a specific bus impact the observed LMP at that bus, and if so how large an impact is there on the LMP; 8) does generating QF power in North Carolina and sending it to the rest of the DOM Zone have a consistent, predictable impact on the LMP differentials; and 9) if the Commission is going to recognize this differential in developing the QF energy rates, whether it would be appropriate for the sake of consistency to also use the same differential to make a downward adjustment factor to the retail energy rates. Tr. vol. 7, pp. 286-289.

Additionally, in the interest of improving price signals and ensuring that ratepayers receive the benefit of optimally located QFs, the Commission expects that, in some cases, the adjustment for locational value may be a downward adjustment and in other cases, an upward adjustment.

Thus, the Commission directs DNCP to provide the requested information, as well as sample calculations, in its initial filing in the 2018 biennial avoided cost proceeding, with the expectation that such an adjustment could be authorized in that proceeding.

<u>Elimination of Avoided Line Loss Value</u>

The proposal DNCP to eliminate the value of avoided line loss is not appropriate at this time but merits study for future consideration.

NCSEA takes the position that, like adjusting rates for locational value, adjusting rates for avoided line losses may be appropriate. NCSEA witness Johnson testifies, generally, that QF development is occurring in many locations in North Carolina, but with further refinement, the rate schedules could provide much more useful and important information regarding different locations and provide corresponding price signals to market participants.

NCSEA witness Johnson testifies that, with additional study and data analysis, detailed location-specific information could be developed that considers: 1) proximity to load centers and other factors which influence line losses; 2) opportunities to reduce congestion on distribution lines, substations, and transmission lines which could postpone or avoid upgrades to these facilities within the relevant planning horizon; and 3) opportunities to improve local reliability. Tr. vol. 7, pp. 283-285.

As is the case with adjustment based on locational value of the QF, the Commission sees merit in DNCP's proposal regarding line loss in the interest of improving price signals to QFs and encouraging QF development in locations that provide maximum benefit to ratepayers. However, along these lines, while it may be appropriate to eliminate the line loss benefit in some cases, it may be appropriate to increase the line loss benefit in other cases. Thus, the Commission directs DEC, DEP and DNCP to provide an explanation of the methodology, as well as sample calculations, for evaluating the line loss benefit provided by a QF in their initial filings in the 2018 biennial avoided cost proceeding, with the expectation that such an adjustment could be authorized in that proceeding.

Solar Avoided Energy Rate

Public Staff witness Hinton recommends that the Commission direct DEC, DEP and DNCP to submit a separate avoided energy credit for solar QF generation, to more accurately reflect the cost that the utility avoids as a result of solar QF generation during off-peak hours. Tr. vol. 8, p. 80. In short, the Public Staff takes the position that energy provided by solar QF generation during certain off-peak daylight hours provides value to the utility and its ratepayers that is not reflected in the current pricing structure.

In spite of the fact that the Commission previously declined to accept this proposal in the 2014 biennial avoided cost proceeding, the Public Staff urges the Commission to reconsider in the instant proceeding. Tr. vol. 8, p. 78. The Public Staff explains that average off-peak avoided energy credits include early morning hours and late-night hours when baseload plants with the lowest marginal costs are operating. The Public Staff further explains that solar generation helps the utility avoid marginal production costs during the middle of the day. The Commission understands the Public Staff's position to be that an average off-peak avoided energy credits that takes into account the early morning and late-night hours dilutes the credit and fails to compensate the solar QF adequately for the value provided to ratepayers. Tr. vol. 8, p. 79.

In the previous biennial avoided cost proceeding, the Commission was concerned that directing the utilities to provide a solar-specific energy credit would be inconsistent with the ultimate goal of accounting for the costs and benefits of integrating various types of renewables into the utilities' networks. However, based on the Public Staff's additional explanation in this proceeding, the Commission concludes that QF solar generation benefits the electric utility during off-peak hours, and, for this reason, it is appropriate for DEC, DEP and DNCP to offer a separate avoided energy rate for solar QFs that more accurately reflects costs avoided by the electric utility during off-peak daytime hours.

AVOIDED CAPACITY COSTS AND RATES
FINDING NOS. 15-16

PAF

DEC and DEP propose to reduce the performance adjustment factor (PAF) from 1.20 to 1.05 to align capacity payments to QFs under the peaker methodology with the reliability equivalent to that of a CT, which is the avoided capacity resource. Tr. vol. 2, p. 276. DEC and DEP make the alternative argument in support of reducing the PAF that it is also reasonable under the peaker method to view the on-peak reliability of baseload generation resources of the DEC and DEP systems as equivalent to a reasonable expectation of QF availability. DEC and DEP argue that a PAF of 1.2 means that a QF must be available only 83% of peak hours in order to receive payments equivalent to 100% of a utility's full avoided capacity cost and that a 95% availability, which equates to a PAF of 1.05, is a more appropriate representation of a unit's availability. Tr. vol. 2, pp. 277-278.

NCSEA takes the position that the proposed reduction is unreasonable and should be rejected.

NCSEA witness Johnson testifies that under the peaker method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units and, hence, Johnson opines that the availability of all types of generating units (intermediate and baseload) must be considered, contrary to the narrower viewpoint expressed by DEC and DEP. Tr. vol. 7, pp. 298-299.

Further, NCSEA witness Johnson testifies that while the precise calculation of the PAF may be disputed, QFs must be treated in a non-discriminatory manner, consistent with the treatment afforded the electric utilities. This is important because QF rates are supposed to leave customers financially indifferent between purchases of QF power and the generation of the same amount of output by the utility. Tr. vol. 7, p. 300.

NCSEA witness Johnson testifies that reducing the PAF to 1.05 would have the effect of requiring a QF to generate at full capacity during 95% of the on-peak hours in order to receive full payment of the avoided capacity costs. Johnson testifies that a solar generator would not receive full payment of the avoided capacity costs, because it is incapable of generating electricity during 95% of the on peak hours due to the fact that many on peak hours occur when the before the sun rises or after the sun sets. Tr. vol. 7, p. 301.

The Public Staff supports a reduction in PAF to 1.16, based on an average baseload availability factor of 86.33%. The Public Staff derived this baseload availability factor by analyzing plant performance data of the Utilities. The Public Staff included baseload and intermediate load generating units in its analysis. Tr. vol. 8, p. 127.

All parties appear to agree that a generic QF should not be held to a standard that requires 100% availability during peak hours to receive payments equivalent to the utility's full avoided cost. Tr. vol. 2, p. 276. The Commission has historically reached this same conclusion and has consistently directed the Utilities to use a PAF of 1.2 in calculating avoided capacity credits, in spite of repeated proposals by DEC and DEP to reduce the PAF.

As the peaker method is applied in North Carolina, a QF is paid an avoided capacity credit only when the QF generates electricity during the electric utility's on-peak hours. The QF is not paid an avoided capacity credit when it generates during the electric utility's off-peak hours; instead, during off-peak hours, the QF may earn only an avoided energy credit. For this reason, the Commission has historically found it reasonable that a PAF be used when calculating avoided capacity credits. It would be unreasonable to expect any generator, whether QF or not, to generate 100% of the time, particularly when the generator does not control its energy resource – such as the wind, the sun or river flow.

In addition, when addressing the last proposal by DEC and DEP to reduce the PAF to 1.05, made in the 2014 biennial avoided cost proceeding, in which DEC and DEP justified the reduction in order to better align with the availability of a natural gas CT, the Commission found that "the availability of a CT is not determinative for purposes of calculating a Performance Adjustment Factor (PAF) because the fixed costs of a peaking unit in the peaker method employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit." Order Setting Parameters, Finding of Fact 23 and Evidence and Conclusions for Findings of Fact 23-25, pp. 54-56. Thus, the Commission rejects the initial justification provided by DEC and DEP for the reduction in PAF for the same reason it was rejected in the 2014 biennial avoided cost proceeding.

Further, the Commission is persuaded by the testimony of NCSEA witness Johnson, as well as its historical review of this issue, that requiring a QF to generate at full capacity during 95% of the on-peak hours in order to receive full payment of the avoided capacity costs is not reasonable. Thus, the Commission rejects the proposal by DEC and DEP to reduce the PAF to 1.05. The Commission has similar concerns with the Public Staff's proposal to reduce the PAF to 1.16, thereby requiring the QF to generate 86.33% of the on-peak hours to receive full payment of the avoided capacity costs, particularly as relates to solar QFs. In short, many of the on-peak hours occur during the very early morning in the winter before the sun has risen and in the evening hours of the summer, once the sun has set. Specifically, the Option A on-peak hours are: June – September and December – March, 7 a.m. – 11 p.m., Monday through Friday. The Option B on-peak hours are Monday - Friday: i) June – September, 1 p.m. to 9 p.m.; ii) and October – May, 6 a.m. to 1 p.m. Thus, a solar QF be generating is likely not generating even 83% of the foregoing on-peak hours and, therefore, is not in a position to earn the full avoided capacity cost. Reducing the PAF, even as advocated by the Public Staff, will further prejudice the solar QF. Thus, the Commission concludes, as it has historically, that a PAF of 1.2 is reasonable and appropriate when calculating avoided capacity credits.

<u>Seasonal Allocation of Avoided Capacity Costs</u>

DEC and DEP have proposed to adjust the allocation of avoided capacity costs between seasons, as follows:

DEC	Option A		Option B	
	On Peak Month	Off Peak Month	Summer	Non-Summer
2014	80%	20%	60%	40%
2016	100%	0%	20%	80%

DEP	Option A		Option B	
	On Peak Month	Off Peak Month	Summer	Non-Summer
2014	60%	40%	60%	40%
2016	20%	80%	20%	80%

NCSEA takes the position that in general, DEC, DEP and DNCP do not propose any improvements to the definitions of on-peak and off-peak hours, which is surprising given most of the problems of which the utilities complain are time-related. Further, NCSEA takes the position that the proposal of DEC and DEP to change the seasonal allocation of capacity costs, without revising the definition of non-summer, should be rejected by the Commission as it is entirely inconsistent with data showing when peak loads actually occur. Tr. vol. 7, p. 307.

NCSEA witness Johnson analyzed hourly load data for DEC and DEP for the years 2006-2015, as filed by the utilities at the FERC on FERC Form 714. Johnson testifies that the hourly load data indicate that approximately 86.5% of the most extreme system peaks (at or above 99% of the annual coincident system peak) occurred during the months of June through September, while the remaining 13.5% occurred during the months of December, January and February. Further, none of these extreme peaks have occurred during any other months. Tr. vol. 7, pp. 309-314.

NCSEA witness Johnson explains that these data are entirely inconsistent with DEC and DEP's proposal to allocate 80% of the capacity costs to a broadly defined non-summer period that starts in October and ends in May. Johnson recommends that if the Commission is going to move away from the 60% Summer 40% Non-Summer allocation that was used in the 2014 biennial proceeding, then any movement should place more emphasis on the hot summer afternoons and less emphasis on months like October, November, April and May – when extreme peaks almost never occur. Tr. vol. 7, p. 317.

Similarly, the Public Staff takes issue with the changes in seasonal allocation. Public Staff witness Hinton expressed concern that the proposed seasonal factors may shift an excessive emphasis toward the winter periods than appropriate. He acknowledged that is true that in the 2014 and 2015 DEC and DEP have experienced significant winter peaks, and in 2014 struggled to satisfy the load conditions on their systems. However, the Public Staff does not believe that the significant shift of avoided capacity values to the winter periods should be made at this time. Hinton testifies that, as the Public Staff stated in its comments in the 2016 IRP Proceeding, the shift of DEC and DEP from summer to winter peaking should not diminish consideration of the summer peak, which remains significant. Additionally, Hinton testified that DEC and DEP are continuing to refine load forecasting capabilities to better understand the growth and impact of DEC's and DEP's winter and summer peaks. The Public Staff takes the position that, until a pattern of winter peaks is better understood and there is more confidence that the utility is a winter peaking utility, shifting to a predominantly winter-centric paradigm may be premature. Tr. vol. 8, pp. 41-42.

Based on the concerns regarding the potential overemphasis on winter peaks in the 2016 IRPs, the Public Staff recommends that DEC and DEP adjust the seasonal weighting to 40% for summer and 60% for non-summer. This recommendation shifts the weighting to a greater emphasis on the non-summer months, but still recognizes the significant summer capacity needs of the utilities. Further, the Public Staff recommends that DEC and DEP continue to monitor seasonal capacity needs to better inform future seasonal allocation decisions. Tr. vol. 8, p. 42.

Given the analysis performed by NCSEA witness Johnson and the concerns of the Public Staff related to overemphasis on winter peaks, the Commission determines that the 60% Summer 40% Non-Summer allocation, used in the 2014 biennial proceeding, is appropriate at this time. However, the Commission determines that it is appropriate to continue to evaluate the seasonal allocation factors used by the Utilities for avoided costs in light of changing seasonal peak load conditions experienced in North Carolina. Therefore, the Commission directs the Utilities in the next biennial proceeding to provide marginal cost data on a season-specific basis with their initial filings in order to determine whether the allocation factors utilized in this proceeding remain reasonable.

LEGALLY ENFORCEABLE OBLIGATION
FINDING NOS. 17-18

The federal regulations 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) (emphasis added). 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) (J.D. 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 to sell its output to the utility. See Order Denying Request for Waivers, N.C.U.C. Docket No. SP-4158, Sub 0, June 15, 2015, p. 6.

DEC and DEP propose to amend the standard for establishing a LEO for QFs in excess of 1 MW. Specifically, DEC and DEP propose that a QF in excess of 1 MW not be eligible to establish a LEO until it has executed and returned a Facilities Study Agreement to the interconnecting utility after having received and accepted the results of the System Impact Study. Tr. vol. 2, p. 449. In support of this proposal, DEC/DEP witness Freeman asserts that "[Duke's] experience does not support that it is even feasible for a QF to make a commitment to provide energy and capacity to the utility over a specified future term prior to completing the System Impact Study." Tr. vol. 2, p. 449. Further, DEC and DEP assert that the current standard assigns the risk of non-performance by the QF to ratepayers, as DEC and DEP are obligated to pay the QF rates that reflect avoided costs as of the date of the LEO but the QF is not similarly obligated to deliver power. Tr. vol. 2, p. 462. In other words, DEC and DEP assert that a QF should be obligated to make a "meaningful" commitment to deliver power before a LEO can be established. Tr. vol. 2, pp. 463-464.

NCSEA objects to the DEC and DEP's proposal because it leaves the QF's ability to establish a LEO outside of the QF's control. NCSEA witness Harkrader testified to the unpredictability and inconsistency that plagues the interconnection process and that, in her experience, the interconnection process now takes longer and is less predictable than prior to the May 2015 revisions to the North Carolina Interconnection Procedures. Tr. vol. 7, pp. 374-375. She testified that, in 2016, her company Carolina Solar Energy II, LLC (CSE) was involved in the interconnection of twelve (12) 5 MW ac solar QFs to the grid. Harkrader projects that that in contrast, in 2017, only four (4) 5 MW ac solar QFs developed by CSE will be interconnected. Further, she testified that one interconnection request made by CSE in the summer of 2014 has still not received results from the study process and that CSE has received only one (1) new System Impact Study back from the utility for a distribution level QF in North Carolina in the past twelve (12) months. Tr. vol. 7, pp. 375-376.

In addition, NCSEA takes issue with the DEC and DEP assertion that a QF cannot make a commitment until it receives the results of the System Impact Study. Specifically, NCSEA witness Harkrader testified that the QF development process involves many steps, only one of which is interconnection, that require the QF to make significant commitments. Tr. vol. 7, p. 383. She testified that: i) the early stages in the development process involve the identification of a suitable site for the facility, the negotiation for site control with the landowner, the completion of environmental surveying and permitting, the securing of land use approvals, and the securing of regulatory approvals; ii) these early stages can take many months, or longer, to complete; and iii) securing rights to the site and all necessary approvals involves significant cost, as well. Tr. vol. 7, p. 383. She also testified that the interconnection process involves significant commitment on the part of the QF. Specifically, she explained that the interconnection request is typically made very early in the process, after site control has been secured. Engineering and design work must be undertaken prior to submitting the interconnection request, and a significant fee, in the case of a 5 MW QF, $25,000, must be paid at the time the interconnection request is submitted. Subsequent to the submittal of the interconnection request, a scoping meeting is held with the relevant personnel for the interconnecting utility, as well as the QF's team of engineers, to discuss the request. From the scoping meeting, the request proceeds to the study process. The process of preparing an interconnection request, submitting to the utility, and holding a scoping meeting with the utility can take several months and involve significant expense, depending on the complexity of the interconnection and the engineering and design resources required. Thus, Harkrader testified that significant commitments—in terms of expenditure of time and financial resources and the securing of necessary approvals—are made toward the development of the QF before the interconnection study process is completed. Tr. vol. 7, pp. 383-384.

In the interest of not placing control over the timing of the LEO squarely with the utility and in light of the commitments made by the QF early in the development process, NCSEA proposes that the LEO standard be amended to require that, before a QF is eligible to transmit the Notice of Commitment form to the purchasing utility until the earlier of: 1) the QF's receipt of the interconnecting utility's System Impact Study for the QF; or 2) 105 days after the QF submits a complete interconnection request to the interconnecting utility.

The Public Staff's proposal to amend the LEO standard is consistent with NCSEA's proposal. Specifically, the Public Staff proposes to amend the standard such that the LEO could be established at the earlier of the completion of the System Impact study or 105 days after the date of the submittal of the interconnection request. In addition, the Public Staff recommends that a QF not be eligible to establish a LEO unless it is a Project A or Project B in the interconnection queue. Tr. vol. 8, pp. 96.

At the outset, the Commission determines that the DEC and DEP proposal is inconsistent with recent declaration of the FERC that "a requirement for a facilities study or an interconnection agreement, given that the utility can delay the facility study or tendering an executable interconnection agreement, as a predicate for a legally enforceable obligation is inconsistent with PURPA and the [FERC]'s regulations under PURPA." In re. FLS Energy, Inc., Notice of Intent Not To Act And Declaratory Order, 157 FERC ¶ 61,211, December 15, 2016 (the <u>FLS Order</u>) paragraphs 20, 23. In that decision, the FERC expressed, clearly and unambiguously, that the "establishment of a legally enforceable obligation turns on the QF's commitment, and not the utility's actions. . . ." <u>FLS Order</u>, paragraph 24.

Additionally, as pointed out by NCSEA witness Harkrader, whose company has developed 39 solar QFs in North Carolina, the timing of the interconnection process is unpredictable and has slowed since 2013. Tr. vol. 7, p. 400. Public Staff witness Lucas corroborated NCSEA witness Harkrader's testimony when he testified that in his opinion the interconnection process does not provide a QF with any certainty as to when interconnection may be achieved. Tr. vol. 8, p. 234. The Commission takes note of the delays that are occurring in the interconnection process; the Commission also takes note, as pointed out by DEC/DEP witness Freeman, that delays in the process may not be solely within the utilities' control. Tr. vol. 2, pp. 464-465. However, completing the study process and constructing the interconnection are within the utilities' control.

With respect to risk to customers of non-performance by the QF, which DEC and DEP cite as the basis for their proposed revision to the LEO standard, based on the evidence in the record, the Commission is not persuaded that any risk is borne by DEC and DEP customers in this context. It seems fairly straightforward that if a QF does not deliver, the electric utility does not purchase its output. In fact, DEC/DEP witness Snider testified on cross examination that QFs are not included in the IRP process until they come online and begin delivering. Tr. vol.4, p. 31.

Further, the Commission is persuaded by NCSEA witness Harkrader that significant commitments are, in fact, made by the QF well in advance of receiving the results of the System Impact Study. Those commitments include securing site control, land use entitlements, permits and approvals, as well as, regulatory permits and approvals, and initiating the interconnection process.

In light of the foregoing, and consistent with the guidance from the FERC that the establishment of a LEO turn on the QF's commitment and not on actions of the electric utility, the Commission adopts the proposal of the Public Staff and NCSEA and hereby rules that, as of the date of this order, a LEO is established when a QF: 1) has received a CPCN; 2) has committed to sell its output to the utility, using the Notice of Commitment form previously approved by the Commission, which form may not be submitted to the purchasing utility until the earlier of i) the QF's receipt of the interconnecting utility's System Impact Study for the QF or ii) 105 days after the QF submits a complete interconnection request to the interconnecting utility.

CURTAILMENT
FINDING NOS. 19-20

DEP complains of operationally excess energy production. DEC and DEP propose to amend their standard terms and conditions to enable the utility to curtail QF generations under certain conditions, as a means of improving operational control during imminent system emergencies. Tr. vol. 2, pp. 82-93.

The Commission acknowledges that the discontinuance of purchases from QFs is authorized under 18 C.F.R. § 202.307(b) during any system emergency, if such purchase would contribute to the system emergency. However, the Commission is without sufficient basis, at this time, to authorize DEC and DEP's proposal to discontinue purchases from QFs during system emergencies. Public Staff witness Metz testified that DEC, DEP and the Public Staff are in discussions regarding DEC's and DEP's adoption of curtailment guidelines. Tr. vol. 8, p. 129. The Commission directs DEC and DEP to file such curtailment protocol in this docket once completed and the Commission shall allow parties 30 days from the date of such filing to provide written comments on the guidance documents. Until such time as the Commission issues an order adopting such curtailment protocol, DEC and DEP shall not amend their respective terms and conditions to allow for the ability to curtail.

STANDARDIZED CONTRACTING PROCEDURES
FINDING NO. 21

DEC and DEP propose to adopt contracting procedures for large QFs in the interest of improving the efficiency of the negotiation process. Tr. vol. 2, p. 469. DEC and DEP assert that the proposal mitigates the issue of "stale" rates, as rates offered to the QF will not become final until the QF makes a legally binding commitment to deliver output to the utility by executing a PPA. Tr. vol. 2, pp. 470-471.

The Public Staff generally agrees with the DEC and DEP proposal in the interest of improving the transparency and efficiency of the negotiation process. Further, the Public Staff recommends that contracting procedures include: 1) specific timeframes for both parties to request information and provide responses; 2) the use of a standardized contract form with clear delineation of any revisions to the standard form; 3) indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and investigate financing; and 4) the opportunity for either party to seek informal resolution of disputes or petition the Commission for arbitration of disputes. Tr. vol. 8, pp. 62-63.

NCSEA generally supports a standardized process, in the interest of certainty and minimizing transaction costs and time. Tr. vol. 7, p. 387. NCSEA witness Harkrader testifies, however, that without express limitations on the utilities' discretion regarding the critical issues of term/duration and fixed rate, a standardized process affords no benefits beyond the process that exists today and has the potential to give rise to disputes and to litigation. Tr. vol. 7, p. 387. Harkrader also testified that the proposal to provide "indicative" pricing for a brief period of time that will be re-calculated after that period of time is inconsistent with the Commission's previously established LEO standard and the federal regulation that affords the QF the opportunity to rates that reflect the utility's avoided cost as of the date of the LEO. Tr. vol. 7, p. 387.

The Commission finds merit in DEC and DEP's proposal for standardized contracting procedures. The Commission agrees that standardizing the contracting process will provide certainty, should minimize transaction costs for all parties, and has the potential to avoid disputes and litigation.

The Commission agrees with the Public Staff that the procedure should include, at a minimum: 1) specific timeframes for both parties to request information and provide responses; 2) the use of a standardized contract form with clear delineation of any revisions to the standard form; 3) indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and investigate financing; and 4) the opportunity for either party to seek informal resolution of disputes or petition the Commission for arbitration of disputes. In the interest of transparency, efficiency, and minimizing conflict, the Commission is particularly interested in the development of a standard contract. In fact, DEC/DEP witness Freeman testified that the companies have already developed a "standard contract" for the purpose of dealing with large QFs. Tr. vol. 4, p. 32.

The Commission directs DEC, DEP, DNCP, the Public Staff and other interested parties to file no later than 30 days following the date of this Order proposed contracting procedures for large QFs. In addition, the Commission directs DEC, DEP and DNCP to file proposed standard contracts. Parties may comment on the proposed standard contracts no later than 14 days following the filing of such contracts.

Notwithstanding the foregoing, the Commission is concerned about the use of liquidated damages provisions in the standard contracts requested hereunder and anticipates the potential for such contractual provisions to discourage QF development rather than address harm suffered by the utility.

Specifically, DEC/DEP witness Freeman testified that such provisions are intended to approximate the harm suffered by the utility in the event of late performance or non-performance by the QF. Tr. vol. 4, p. 28. Freeman also testified that liquidated damages are derived from a one-year value of capacity and reflect the cost the utility would incur if it were to procure replacement capacity in the market. Tr. vol. 4, p. 29.

The Commission's understanding, based on the testimony of DEC/DEP witness Snider, is that a QF is not counted in the IRP for planning purposes, until it begins to deliver. To the extent the utilities' standard contracts involve liquidated damages provisions, the utilities must justify the calculation of such damages with explanation of the circumstances under which the utility would cover for a QF that fails to deliver and provide all instances in which the utility has been forced to produce replacement capacity due to non-delivery by a QF.

Finally, the objective of the DEC and DEP proposal for standardized contracting procedures appears to be minimizing the time between the date on which the rates offered to the QF are calculated and the date on which the QF begins to deliver. The Commission understands DEC/DEP witness Freeman's testimony on liquidated damages to mean that liquidated damage provisions are intended to motivate the QF to achieve timely delivery and to penalize the QF in the event that timely delivery does not happen. The Commission understands that timely delivery may not occur due to delays in the interconnection process, which may be beyond the control of the QF. However, as NCSEA witness Harkrader, on cross examination, explained that, in her experience, it was critical to match the in-service date provided in the interconnection process with the commercial operation deadline established in the PPA. Tr. vol. 7, p. 428. Thus, failure to timely deliver could very well be the result of the utility, as opposed to the QF. In fact, the record in this proceeding reflects the uncertainty and unpredictability associated with the interconnection process. Penalizing a QF for failing to deliver timely if such failure is based on interconnection delay beyond the control of the QF is not reasonable and will not be allowed. Thus, any provision for liquidated damages in a proposed standard contract must provide relief in the instance of delay due to the actions of the utility.

IT IS, THEREFORE, ORDERED as follows:

1. DEC, DEP and DNCP shall 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 Offer). The standard levelized rate options of ten or more years should include an option to renew on substantially the same terms and conditions and at a rate either (a) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided costs and other relevant factors or (b) 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. DNCP shall 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 following conditions: (a) any QF choosing to enter into a contract using the PJM market pricing method will be allowed to terminate its existing Schedule 19-LMP contract without paying termination charges after the first year upon 90-days prior written notice and, in doing so, enter into a new five-year, ten-year, or 15-year Schedule 19-FP contract at its option; and (b) DNCP is required to calculate avoided cost payments under each method for the next two years and report the resulting comparison to each QF and the Commission.

3. DEC, DEP, and DNCP shall offer QFs not eligible for the Standard Offer the following three options if the electric utility has a Commission-approved competitive procurement process underway: (a) participating in the electric utility's competitive procurement 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 Commission-approved competitive procurement process 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; 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 a Commission-approved competitive procurement process 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 a Commission-approved competitive procurement process 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 competitive procurement process 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. At such time when there is a Commission-approved competitive procurement process underway for the electric utility, the threshold at which any QF qualifies for the Standard Offer shall be reduced to one (1) MW.

5. In calculating avoided capacity costs: i) the Utilities shall ascribe avoided capacity value to the QF in every year of the contract term, regardless of whether the IRP shows a capacity need in any particular year; ii) the Utilities shall use a PAF of 1.2

6. The seasonal allocation of avoided capacity costs for the purposes of developing avoided capacity credit shall remain at 60% summer and 40% winter.

7. In calculating avoided energy costs: i) the Utilities shall construct fuel forecasts using a blend of forward and fundamental data, with no more than five (5) years of forward data being used; ii) the Utilities shall offer an avoided energy credit that is fixed over the term of the PPA and based on avoided cost estimates over the term of the PPA; iii) the Utilities shall not adjust for locational value at this time; iv) the Utilities shall include a line loss benefit at this time.

8. The Utilities shall offer a separate avoided energy rate for solar QFs that more accurately reflects costs avoided by the electric utility during off-peak daytime hours.

9. At this time, the Utilities shall not include integration costs, or any other similar costs, in the avoided cost calculation.

10. The method by which avoided costs are calculated should remain consistent in both standard and negotiated contracts, and if a method is not applicable to calculating the avoided costs of a "small" QF, the fact that a QF is a "large" QF does not validate such a method.

11. As of the date of this order and going forward, in order for QF to establish a LEO, the a QF must: 1) have been granted a certificate of public convenience and necessity; and 2) transmitted a Notice of Commitment form to the purchasing electric utility. It is appropriate to require that, before a QF is eligible to transmit the Notice of Commitment form to the purchasing utility until the earlier of: 1) the QF's receipt of the interconnecting utility's System Impact Study for the QF; or 2) 105 days after the QF submits a complete interconnection request to the interconnecting utility.

12. DEC and DEP shall file their curtailment protocol in this docket once completed, and the Commission shall allow parties 30 days from the date of such filing to provide written comments on the guidance documents. Until such time as the Commission issues an order adopting such curtailment protocol, DEC and DEP shall not amend their respective terms and conditions to allow for the ability to curtail.

13. The Commission directs DEC, DEP, DNCP, the Public Staff and other interested parties to file no later than 30 days following the date of this Order proposed contracting procedures for large QFs. In addition, the Commission directs DEC, DEP and DNCP to file proposed standard contracts. Parties may comment on the proposed standard contracts no later than 14 days following the filing of such contracts.

14. The Commission directs DEC, DEP and DNCP to recalculate their avoided costs and associated avoided energy and avoided capacity credits, revise rate schedules, standard terms and conditions and standard power purchase agreements as necessitated, and file within 30 days of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the __ day of ______________, 2017.

NORTH CAROLINA UTILITIES COMMISSION