STATE OFNORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012	))))	PROPOSED ORDER OF DOMINION NORTH CAROLINA POWER

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on October 29, 2013, at 1:00 pm and on October 30, 2013, at 9:00 am.

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

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BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings also are held pursuant to the responsibilities delegated to this Commission under G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC prescribe the responsibilities of FERC and of State regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

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

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

This proceeding also is a result of the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in FERC regulations regarding factors to be considered in the determination of avoided cost rates. 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 other types of renewable resources.

On June 18, 2012, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing (Scheduling Order). That Order made Duke Energy Carolinas, LLC (DEC), Progress Energy Carolinas, Inc. (DEP), Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU) and New River Power and Light Company (New River) parties to the proceeding in order to establish the avoided cost rates each is to pay for power purchased from QFs pursuant to Section 210 of PURPA and the associated FERC regulations and G.S. 62-156. The Order also required each electric utility to file proposed rates and proposed standard form contracts.

The Scheduling Order stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules rather than a full evidentiary hearing. DEP, DEC, DNCP, New River and WCU were required to file their statements and exhibits by November 1, 2012. Other persons desiring to become parties were initially required to seek permission to intervene and to file their comments, statements and exhibits by January 7, 2013; this deadline was subsequently extended to February 7, 2013. All parties were allowed to file reply comments by February 13, 2013 and proposed orders by March 13, 2013. The Commission scheduled a public hearing for

February 12, 2013, solely for the purpose of taking non-expert public witness testimony. Finally, the Commission required DEP, DEC, DNCP, New River and WCU to publish notice and submit affidavits of publication no later than the date of the hearing.

On June 25, 2012, DEP filed confidential avoided cost data and on November 1, 2012 DEP, DEC, DNCP, WCU and New River filed statements, comments and/or exhibits in accordance with the Commission's June 18, 2012 order. DNCP subsequently filed corrected comments, exhibits and avoided cost schedules on November 5, 2012 (DNCP Initial Filing).

The North Carolina Sustainable Energy Association (NCSEA), the Public Works Commission of Fayetteville (FPWC), and Carolina Utility Customers Association, Inc. (CUCA) filed petitions to intervene, all of which were granted. The Carolina Industrial Group for Fair Utility Rates I, II and III (CIGFUR), Renewable Energy Group (REG), North Carolina Electric Membership Corporation (NCEMC) and Southern Alliance for Clean Energy (SACE) subsequently filed petitions to intervene, which were also granted.

On November 1, 2012, DEP also filed a Motion to Suspend Availability of Previously Approved Long-Term Rates. The motion sought authorization to make available to QFs the currently approved variable rates in Schedule CSP-27 during the period of time between December 1, 2012 and the date that the Commission issues an order setting rates in this docket. On November 6, 2012, NCSEA filed a brief in opposition to DEP's motion, and on November 8, 2012, the Commission requested comments on DEP's motion. On November 21, 2012, REG, NCSEA, EWP LLC, and the Public Staff filed comments, and on December 5, 2012, DEC and DEP filed joint reply comments, and the Public Staff and REG also filed reply comments.

On December 21, 2012, after considering comments filed by the Public Staff and other intervenors, the Commission issued an order granting DEP's motion to suspend availability of rates subject to conditions and requiring that DEP offer their proposed long-term fixed avoided cost rates subject to true-up pending a final order establishing rates in this docket.

On December 21, 2012, the Public Staff filed a motion to extend deadlines for intervenor comments, reply comments and proposed orders, which the Commission granted on December 28, 2012, allowing comments to be filed on February 7, 2013, reply comments on March 15, 2013, and proposed orders on April 15, 2013. On February 7, 2013, the Public Staff, NCSEA and REG filed initial comments.

On or before February 12, 2013 all electric utilities filed Affidavits of Publication of the Notice of Hearing, and the public hearing was held in the hearing room on February 12, 2013 as scheduled. Seven witnesses gave testimony at that hearing. In addition, several consumer statements of position have been filed in this docket.

On March 14, 2013, DEC and DEP filed a joint motion for extension of time to file reply comments, which the Commission granted on March 15, 2013. Subsequently on March 22, 2013, the Public Staff filed a motion for a further extension of time to file reply comments, which the Commission granted on March 25, 2013, allowing reply comments to be filed on March 28, 2013.

On March 28, 2013, reply comments were submitted by the Public Staff, DNCP, and jointly by DEP and DEC. NCSEA also filed a motion asking the Commission to consider scheduling an evidentiary hearing and directing that DEC's and DNCP's proposed fixed long-term avoided cost rates go into effect on a temporary basis, subject to true-up following the Commission's final order in this proceeding. In response to the reply comments and request for an evidentiary hearing, on April 1, 2013, the Commission suspended the deadline for proposed orders and gave all parties the opportunity to file comments on the request for an evidentiary hearing. On April 8, 2013, DNCP filed comments in opposition to calendaring an evidentiary hearing, as did DEC and DEP in joint comments on the same date.

On May 14, 2013, the Commission issued an order directing DEC and DNCP to offer their proposed long-term fixed avoided cost rates subject to true-up pending a final order establishing rates in this docket. DEC subsequently filed its avoided cost rates in compliance with this order on June 13, 2013, and DNCP filed its avoided cost rates on August 15, 2013.

On June 6, 2013, the Commission issued an order scheduling an evidentiary hearing on September 10, 2013 and establishing the procedural schedule. On June 26, 2013, the Public Staff filed a motion to revise the procedural schedule, to postpone the hearing and extend the related filing dates. On July 1, 2013, the Commission granted the motion, rescheduling the hearing for 9:30 a.m. on October 29, 2013. On August 1, 2013, to avoid potential confusion, DEP filed its interim schedule CSP-27B in compliance with the Commission's December 21, 2012 order, which had not required the filing of revised rates pending the Commission's final order in this docket.

On August 6, 2013, DEP and DEC submitted a joint motion for extension of time to file testimony, which the Commission granted on August 8, 2013. On August 9, 2013, DNCP filed the direct testimony and exhibits of Bruce E. Petrie and Robert J. Trexler. On August 13, 2013, DEC and DEP filed the direct testimony and exhibits of Kendal C.

Bowman, Glen A. Snider and Theodore P. Pintcke. On September 27, 2013, REG filed the direct testimony of John E.P. Morrison and Don C. Reading and the affidavit of Erik Stuebe; the Public Staff filed the direct testimony of Kennie D. Ellis and John R. Hinton; and NCSEA filed direct testimony and exhibits for Karl R. Rábago. On October 18, 2013, DEC and DEP jointly filed the rebuttal testimony of Mr. Snider and Ms. Bowman; DNCP filed the rebuttal testimony of Mr. Petrie and Mr. Trexler; and NCSEA filed a report prepared by Crossborder Energy. On October 25, 2013, DNCP, DEC and DEP filed a joint motion to strike NCSEA's October 18, 2013 correspondence and report. NCSEA responded to the joint motion on October 25, 2013, and on October 28, 2013 the Commission denied the motion to strike.

Having received from DEC and DEP on October 28, 2013 an oral notice of a settlement with the Public Staff and a request to delay the hearing to allow time to file the settlement agreement, the Commission issued an order rescheduling the hearing to begin at 1 p.m. on October 29, 2013. On October 29, 2013, the Public Staff, DEC and DEP jointly filed a Stipulation of Settlement. On that date, DNCP and the Public Staff also jointly filed a Stipulation of Settlement. The evidentiary hearing was held as scheduled on October 29 and October 30, 2013.

Following the hearing, proposed orders were filed by the parties on December 20, 2013.

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

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

FINDINGS OF FACT

1. DNCP should be required to offer long-term levelized capacity rates and energy rates for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five megawatts (MW) or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. DNCP should offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

2. DNCP’s proposed Schedule 19-FP, as modified as provided in this order, is reasonable and should be approved.

3. It is appropriate for DNCP to close Schedule 19-DRR to all QFs except for those QFs that have a currently effective contract with DNCP under Schedule 19-DRR. DNCP shall continue to update, maintain and file Schedule 19-DRR for approval by the Commission until such time as there are no longer any QFs with a contract under Schedule 19-DRR.

4. It is appropriate for DNCP to offer, as an alternative to avoided cost rates in Schedule 19-FP derived using the peaker method, avoided cost rates in Schedule 19-

LMP based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM).

5. At the request of a QF, DNCP shall calculate comparisons of avoided cost payments using the Schedule 19-FP method and the Schedule 19-LMP method. DNCP shall file these comparisons with the Commission in this docket at the time they are provided to the QFs.

6. DNCP's Schedule 19-FP and Schedule 19-LMP tariffs approved in this proceeding shall be available to any eligible QF that enters into a contract with DNCP and begins delivering power to the Company by December 31, 2014.

7. DNCP's inclusion of a regulatory disallowance clause in its standard contracts for purchases of energy and capacity pursuant to Schedule 19-DRR, Schedule 19-FP and Schedule 19-LMP is reasonable and should continue to be allowed.

8. DNCP should offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a Commission-recognized active solicitation underway, it should offer QFs not eligible for the standard long-term levelized rates the option of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings or (2) contracting with the utility to sell power at negotiated rates. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for

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

9. The peaker method is generally accepted and used throughout the electric utility industry and its use by DNCP for its proposed Schedule 19-FP is reasonable for use in this proceeding.

10. A performance adjustment factor (PAF) of 2.0 should be used by DNCP in its avoided capacity rate calculations for this proceeding for hydroelectric facilities with no storage capability and no other type of generation. A PAF of 1.2 shall be utilized by DNCP for all QFs that do not qualify for a PAF of 2.0.

11. DNCP shall offer the avoided capacity rates proposed by DNCP in Schedule 19-FP as Option A under that schedule. In addition, DNCP shall modify Schedule 19-FP to include Option B avoided capacity rates as described in this Order.

12. DNCP's proposal of an annual maximum or "cap" on capacity payments resulting from the application of a PAF is reasonable and should be approved.

13. The estimated installed CT costs used by DNCP to calculate its avoided capacity costs and avoided cost rates are reasonable and should be approved, and DNCP's proposed avoided cost rates are reasonable and should be approved.

14. DNCP, REG and Public Staff shall discuss the structure and availability of two-year variable energy and capacity rates in Schedule 19-FP.

15. The rate schedules and standard contract terms and conditions proposed in this proceeding by DNCP should be approved except as otherwise discussed herein.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 1

No party to this proceeding proposed to change the availability of long-term levelized rate options for the specified QFs contracting to sell 5 MW or less capacity or the availability of five-year levelized rate options to all other qualifying facilities contracting to sell 3 MW or less capacity. The Commission has consistently concluded in prior avoided cost proceedings that it must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next and that, in doing so, it must balance the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs on the other. The Commission continues to believe that its decisions in the most recent past avoided cost proceedings strike an appropriate balance between these concerns. The Commission, therefore, concludes that DNCP should offer long-term levelized rate options of five-, ten- and 15-year terms to hydro QFs contracting to sell 5 MW or less and to QFs contracting to sell 5 MW or less that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass, and that it should offer its five-year levelized rate options to all other qualifying facilities contracting to sell 3 MW or less capacity. With these limitations, long-term contract options serve important statewide policy interests while reducing the utilities' exposure to overpayments and should continue to be made available.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence to support this finding of fact is contained in the DNCP Initial Filing at pages 1-4, the Initial Statement of Public Staff, and the Commission's final order in Docket No. E-100, Sub 127.

The Commission's final order in Docket No. E-100, Sub 127 dated July 27, 2011 (the 2010 Biennial Order) directed DNCP to file in this proceeding "long-term levelized capacity payments and energy payments calculated pursuant to the DRR method based on long-term levelized generation mixes with adjustable fuel prices for five-year, ten-year and 15-year periods…" for eligible QFs. In addition, the Commission directed DNCP to file "proposed fixed long-term levelized avoided energy rates for QFs entitled to standard contracts."

DNCP has proposed to establish a new rate schedule, "Schedule 19-FP," that will be available to all new standard rate QFs (i.e., those QFs that enter into a contract with the Company after January 1, 2013). Schedule 19-FP will offer QFs fixed long-term energy rates, as well as the other standard rate options (e.g., "as available" energy payments). Schedule 19-FP also introduces seasonal on-peak and off-peak hours, which DNCP believes reasonably reflects its customers' actual peaks during the year, and payments for capacity during on-peak hours only.

Previously, the Company calculated avoided capacity costs using PJM capacity auction clearing prices in the short term, blending to capacity price forecasts in the long term. In lieu of this method, DNCP has in this proceeding calculated avoided capacity costs using the "peaker" method. DNCP believes the peaker method accurately represents its avoided capacity costs, as it is consistent with the results of DNCP's 2012 IRP, and responds to concerns raised in previous proceedings regarding DNCP's use of PJM forward capacity auction clearing prices to determine avoided capacity rates.

DNCP will continue to utilize the same method for calculating avoided cost energy rates as it has done in the past. No party challenged DNCP's methodology for calculating avoided energy rates or DNCP's proposed avoided energy rates.

In its Initial Statement, Public Staff stated that DNCP's proposed Schedule 19-FP complies with the Commission's directives in the 2010 Biennial Order. Public Staff supported DNCP's use of the peaker methodology as reflected in Schedule 19-FP.

No other party expressed opposition to the Company's proposed introduction of Schedule 19-FP, which as discussed below will ultimately replace Schedule 19-DRR.

Based upon the foregoing, and subject to the modifications discussed below in Discussion and Conclusions for Findings of Fact Nos. 9 and 11, the Commission concludes that DNCP's proposed Scheduled 19-FP is reasonable and is approved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence to support this finding of fact is contained in the DNCP Initial Filing at pages 2-3.

In this proceeding, the Company proposed to establish a new rate schedule, Schedule 19-FP (discussed above). Contingent upon the Commission's acceptance of Schedule 19-FP, the Company proposed to close Schedule 19-DRR to all QFs except for those that have a currently effective contract with the Company under Schedule 19-DRR

(Grandfathered QFs). The Company will continue to maintain, update and file Schedule 19-DRR for approval by the Commission until such time as there are no longer any Grandfathered QFs.

As explained by DNCP, at the time of its initial filing in this proceeding there were five North Carolina QFs that would be Grandfathered QFs. Three were existing Schedule 19-DRR QFs already delivering power to the Company, and two had contracts under existing Schedule 19-DRR, but had not achieved commercial operations as of the date of the DNCP Initial Filing in this proceeding.[1] As the capacity prices for the Grandfathered QFs are fixed for the term of their existing contracts with the Company, only the energy prices for the Grandfathered QFs will be affected by future adjustments to Schedule 19-DRR in biennial proceedings. This means that Grandfathered QFs will not be affected by the change in the method for determining avoided capacity costs proposed by the Company in its new Schedule 19-FP, discussed above. In addition, because they have existing contracts, the energy payments to Grandfathered QFs will not be subject to the proposed seasonally adjusted on and off-peak hour definitions under Schedule 19-FP, also discussed below. Finally, DNCP will offer each Grandfathered QF the opportunity to switch to Schedule 19-FP by entering into a new Schedule 19-FP contract with a term equal to the remaining duration of the Grandfathered QF's existing Schedule 19-DRR contract.

No party objected to the DNCP proposal to close Schedule 19-DRR, as described above.

[1] As of the date of the filing of DNCP's proposed order in this proceeding, there are only two Grandfathered QFs. Of the original five Grandfathered QFs, two moved from Schedule 19-DRR to Schedule 19-FP and one contract terminated.

Because the Commission is approving DNCP's proposed Schedule 19-FP, as discussed above, the Commission finds it is reasonable for DNCP to close Schedule 19-DRR to all QFs but Grandfathered QFs and, at such time as no Grandfathered QFs remain under Schedule 19-DRR, DNCP will not longer have the obligation to file Schedule 19-DRR as part of these biennial proceedings.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 AND 5

The evidence to support this finding of fact is contained in the DNCP Initial Filing at pages 3, 16-17, and the 2010 Biennial Order.

DNCP proposed to continue to offer Schedule 19-LMP as a voluntary alternative available to QFs. In proposed Schedule 19-LMP, energy prices are based on the hourly PJM Dom Zone Day Ahead Locational Marginal Price (DA LMP) expressed as $/MWh. For QFs that are providing energy and capacity, the DA LMP values, divided by 10 (to derive a cents per kWh price), are applied to the respective hourly net output of the QF generation.For QFs that are providing energy only, the average of the DA LMP values in the billing month, divided by 10 (to derive a cents per kWh price), is applied to the QF's total net generation during the billing month.

Capacity credits for Schedule 19-LMP would be paid on a cents per kWh rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DNCP used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs, which are the prices per MW per day from PJM's Base Residual Auction for the Dom Zone. As proposed in the last proceeding, DNCP adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days.The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period June 1 through September 30). The SPPF will vary depending upon the QF's prior year's operations.

In its prior orders approving DNCP's Schedule 19 LMP offering, for any QF that enters into a Schedule 19 contract, the Commission has required that DNCP calculate avoided cost payments using both the Schedule 19-DRR method and the Schedule 19-LMP method for the next two years and to provide such comparison to each QF receiving payments under Schedule 19-DRR or Schedule 19-LMP at least once every six months, with the first report due not later than eight months from the QF contract date. DNCP is required to file these rate comparisons with the Commission at the same time that they are provided to the QFs. DNCP has requested that the Commission modify this requirement. Specifically, DNCP notes that with the closure of Schedule 19-DRR, the rate comparison should be between new Schedule 19-FP and Schedule 19-LMP. Second, DNCP requests that it only be required to provide the comparisons between Schedule 19-FP payments and Schedule 19-LMP payment when requested by a QF. If such a comparison is requested by a QF, DNCP would file the comparison with the Commission at the same time it is provided to the QF.

No party objected to DNCP's proposal to continue to offer Schedule 19-LMP as a voluntary alternative available to QFs or its proposed modifications to the rate comparison filing requirements.

Based upon the foregoing, the Commission concludes that DNCP should continue to be permitted to offer Schedule 19-LMP in addition to Schedule 19-FP and approves DNCP's requested modifications to the rate comparison filing requirements. DNCP shall provide a comparison of the prices derived by the Schedule 19-FP method and the Schedule 19-LMP method in its next biennial proceeding filing.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence to support this finding of fact is contained in the DNCP Initial Filing at pages 5-6, the DNCP Reply Comments, dated March 28, 2013 (DNCP Reply Comments), at pages 6-9, the Public Staff's Initial Statement, the Commission's orders as cited in this section, and 18 C.F.R. § 292.304.

DNCP's proposed Schedule 19-FP and Schedule 19-LMP are available to any eligible QF with a Certificate of Public Convenience and Necessity (CPCN) (if a CPCN is required for the QF facility) that enters into a contract with DNCP and begins deliveries of power to the Company prior to December 31, 2014 (the Availability Deadline). DNCP explains that December 31, 2014 is the Availability Deadline because that is the end of the two-year period forming the basis for the estimated avoided cost rates contained in the schedules proposed in this proceeding (the Biennial Period). During the interval between January 1, 2013, and the Commission's final order in this proceeding, the Company will enter into contracts with QFs that can meet the Availability Deadline at the rates and terms and conditions contained in its proposed Schedule 19 schedules. These rates and terms and conditions would then be trued-up to reflect any increase in the rates approved by the final order in this proceeding.

A QF that will not begin delivery of power during the Biennial Period (a Non-Period QF) will not be eligible for the avoided cost rates and contracts approved during this proceeding. Instead, the Company will enter into contracts with Non-Period QFs at rates, terms and conditions contained in the then-proposed or -approved Schedule 19 that covers the Biennial Period in which the QF will begin deliveries of power.

In its Initial Statement, the Public Staff argued that DNCP's tariffs are inconsistent with recent Commission precedent (citing *In the Matter of EPCOR USA North Carolina LLC v. Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.*, Docket No. E-2, Sub 966, Order on Arbitration, Jan. 26, 2011; *In the Matter of Economic Power & Steam Generation, LCL v. Virginia Electric and Power Company, d/b/a Dominion North Carolina Power*, Docket No. SP-467, Sub 1, Order on Arbitration, Jun. 18, 2010 ("*EP&S Order*") (together, the "Arbitration Orders") and with PURPA. Public Staff asserted that when the Commission previously approved the Availability Deadline provision, it had "not yet established the parameters of the 'legally enforceable obligation' (LEO) concept based upon the FERC's decisions in *J.D. Wind 1, LLC*." Public Staff noted that in the Arbitration Orders, the Commission determined that "the prerequisites for an LEO to have occurred or to have been created were the QF having a [CPCN] and having made it sufficiently clear to the utility that it wanted to commit itself to sell its output pursuant to an LEO over a specified term." The Public Staff recommended that QFs that file their applications for CPCNs or reports of construction no later than the November 1 filing date of new proposed avoided costs (or the actual filing date, if later) are entitled to any of the avoided cost rate options in the currently approved avoided cost rate schedules, including the long-term options (assuming they are otherwise eligible).

DNCP responded that the Biennial Period/Availability Deadline provision was reflected in DNCP's Schedule 19 rates filed as part of the previous biennial proceeding, where the Commission "agree[d] with [DNCP] that limiting the availability of Schedule 19-DRR rates to QFs that can deliver power during the Biennial Period is reasonable, consistent with PURPA and Commission orders implementing PURPA, and should continue to be approved," and also "conclude[d] that [DNCP's] policy with respect to Non-Period QFs is reasonable." 2010 Biennial Order at 16.

DNCP noted that while the Commission did initially approve the Company's Schedule 19 provision incorporating the Availability Deadline prior to FERC's *JD Wind* orders and the Commission's own Arbitration Orders, it issued the 2010 Biennial Order, concluding that the Availability Deadline provision and Non-Period QF policy are reasonable, *after* the issuance of the *JD Wind* orders and Arbitration orders. DNCP argued that this indicated that the Commission continued to approve of this provision and policy as being consistent with the intervening precedent.

DNCP also explained that the Availability Deadline and its policy regarding Non-Period QFs is consistent with PURPA and with FERC and Commission precedent.

First, DNCP explained that avoided costs determined in the Commission's biennial proceedings are necessarily based on the assumption that QFs will begin power deliveries during the Biennial Period. For example, in this proceeding, DNCP's Schedule 19-FP rates are all based on the assumption that a QF will start delivering power to the utility in either 2013 or 2014. Accordingly, the avoided energy and capacity rates start in 2013 or 2014, as applicable, and run for 5, 10 or 15 years from 2013 or 2014, as applicable. No avoided cost rate estimates will be developed or approved in this proceeding for QFs that begin operating in 2015, 2016, or beyond. Thus, even assuming that a Non-Period QF was otherwise entitled to Schedule 19 rates as approved in this proceeding, new avoided cost estimates would need to be calculated for years not covered by the Schedule 19 rates approved in this proceeding, using different data and assumptions from those used in the Schedule 19 rates approved here. As such, DNCP argues that Public Staff's proposal that QFs that file CPCN applications or construction reports prior to the new proposed avoided costs filing date are entitled to any rate options contained in currently approved avoided cost rate schedules is not a workable outcome. Such a proposal would mean that a QF that filed for—but did not yet receive—a CPCN prior to November 1, 2014, and that did not plan to begin delivering power to DNCP until after December 31, 2014, would still qualify for standard avoided cost rates approved in this proceeding, even though those rates were calculated using data and assumptions applicable to the commencement of delivery of power in 2013-2014 and not beyond.

DNCP also explained that its existing policy with respect to Non-Period QFs (which the Commission also approved in the previous proceeding) is to enter into contracts with those QFs at the rates and terms and conditions contained in the then-proposed or -approved Schedule 19 that covers the applicable biennial period, subject to true-up on the Commission's final order in that proceeding. Applying this policy to the currently proposed Schedule 19 rates, during the interval between January 1, 2013, and the Commission's order in this proceeding, DNCP stated that it would enter into contracts with QFs that can meet the Availability Deadline at the rates and terms and conditions contained in its proposed Schedule 19-FP and Schedule 19-LMP. These rates and contract terms will be trued-up if needed to reflect any increase in the rates approved in the Commission's final order in this proceeding. DNCP said that it will enter into contracts with Non-Period QFs that cannot meet the Availability Deadline in this proceeding at the rates and terms and conditions contained in Schedule 19-FP and Schedule 19-LMP as proposed in the next biennial proceeding.

DNCP also contended that a QF choosing to receive avoided cost rates based on a LEO would not, as Public Staff suggests, entitle a Non-Period QF to the avoided cost rates contained in Schedule 19 as proposed in this proceeding. DNCP cited to section 292.304(d) of FERC's regulations, which provides a QF with the right to provide energy "as available," or "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term," and which, in the latter case, allows the QF to choose between rates based on either the avoided costs calculated at the time of delivery, or the avoided costs calculated at the time the obligation is incurred. DNCP agreed with Public Staff that the meaning of this latter option was at issue in the EPCOR and EP&S proceedings. In the *EP&S Order*, the Commission held that the QF in that case was entitled to avoided cost payments "based upon forecasts using data as of the time the [LEO] is incurred." *EP&S Order* at 7-9.

Thus, DNCP concluded, under the plain language of the FERC rule, and consistent with the Commission's rulings in the EP&S proceeding, a Non-Period QF invoking the option to receive "avoided costs calculated at the time the obligation is incurred" would not be entitled to the Schedule 19 rates to be approved in this proceeding. Instead, such a QF would be entitled to avoided costs "based upon forecasts using data as of the time the [LEO] is incurred." For example, a Non-Period QF that established an LEO in October 2014 for a facility that would begin delivering power in December 2016 would not be entitled to avoided cost rates approved in this proceeding, but rather avoided cost rates calculated at the time of the LEO. This means that such avoided cost estimates would be based upon forecasts using data available in October 2014, not forecasts based on data used in the instant proceeding. This would result in potentially endless rounds of calculations of avoided costs as of each QF's LEO, which would defeat the entire purpose of establishing standard rates, which is—as stated by the Commission in the 2010 Biennial Proceeding—"to allow small QFs, and utilities, to avoid the transactional cost of individual rate estimates and contract negotiations." 2010 Biennial Order at 16.

In addition, DNCP contended that the LEO option suggested by the Public Staff is inconsistent with the FERC regulations establishing the standard rate requirement. Those regulations require the Commission to put standard rates into effect for QFs with a design capacity of 100 kW or less. As permitted by 18 C.F.R. § 292.304(c)(2), the Commission has expanded the application of standard rates to QFs of five MW or less. Standard rates adopted by the Commission are required to be "consistent with paragraphs **(a) and (e)** of [18 C.F.R. § 292.304]." 18 C.F.R. § 292.304(c)(3)(i) (emphasis added). In short, the LEO requirement embodied in 18 C.F.R. § 292.304(d), on which Public Staff relies, is not applicable to Commission approved standard rates. Even if 18 C.F.R. § 292.304(d) did apply, which DNCP does not believe to be the case, as discussed above, it would not entitle a Non-Period QF to DNCP's standard rates, but rather to avoided cost rates calculated at the time the obligation was incurred, using data as of the time of the establishment of the LEO. As discussed above, this would embroil the Commission and the Company in myriad individual rate setting proceedings, which would be the antithesis of the purpose of standard rates under PURPA.

Finally, DNCP argued that Public Staff's suggestion that QFs that file their applications for CPCNs or reports of construction by November 1 or the actual filing date of new proposed avoided costs are entitled to any of the avoided cost rate options in the currently approved avoided cost schedules is not consistent with FERC regulations and this Commission's precedent. DNCP explained that this proposal is inconsistent with the Commission's own guidance for establishment of an LEO in the Arbitration Orders as discussed above and is not required by FERC's *JD Wind* precedent. Similarly, under such a proposal, if a QF were not going to deliver power to the utility until after the Biennial Period, the avoided costs "calculated at the time the obligation is incurred" and "based upon forecasts using data as of the time the [LEO] is incurred" would not be accurate, since the data used to calculate those costs would pertain to a Biennial Period in which the QF is not operating.

Based on the record in this proceeding and recent Commission precedent regarding these issues as discussed herein, the Commission agrees with DNCP that limiting the availability of Schedule 19 rates to QFs that enter into a contract with DNCP and can deliver power during the Biennial Period continues to be reasonable and consistent with PURPA and should be approved. In addition, the Commission concludes that DNCP's policy for addressing the needs of Non-Period QFs is reasonable, and agrees that the LEO option provided to QFs under paragraph (d) of Section 292.304 of FERC's regulations does not entitle QFs to the Schedule 19 rates approved in this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence to support this finding of fact is contained in the testimony of DNCP witness Robert J. Trexler, the testimony of REG witness Mr. John E. P. Morrison, the affidavit of REG witness Mr. Erik Stuebe, and the Commission orders and court decisions cited in this section.

Article 6 of DNCP's proposed Agreement for the Sale of Electrical Output to Virginia Electric and Power Company for each of Schedule 19-DRR, Schedule 19-FP and Schedule 19-LMP (PPA)[2] deals with a situation in which a regulatory body with jurisdiction, such as this Commission, the Virginia State Corporation Commission (VSCC) or the Federal Energy Regulatory Commission (FERC), issues an order (a Disallowance Order) that (1) prohibits rate recovery of payments made to a QF, and/or (2) requires the Company to refund to its ratepayers payments already made to a QF (the Regulatory Disallowance Clause). In the event of such a Disallowance Order, the Regulatory Disallowance Clause provides that rates under the applicable Schedule 19 will be reset on a prospective basis at the levels that the Company is allowed to recover in rates. Further, if a Disallowance Order requires the Company to refund to ratepayers previous payments to a QF, then the QF is similarly required to refund the Company those amounts.

REG filed the Affidavit of Mr. Erik Stuebe addressing the Regulatory Disallowance Clause. Mr. Stuebe stated that he has been involved in attempting to secure financing for multiple five MW solar QF projects under development by his company, Ecoplexus, Inc., in DNCP's North Carolina service territory. Mr. Stuebe stated that the

[2]These PPAs were appended to the DNCP Initial Filing as Exhibits DNCP-12, DNCP-13 and DNCP-15, respectively.

two lenders he approached seeking financing for these projects declined to finance the proposed QFs because of Article 6 of the Schedule 19-FP PPA and that, based on this experience, Article 6 was a barrier to financing the projects.

REG also submitted the direct testimony of Mr. John E. P. Morrison, chief operating officer of Strata Solar, LLC (Strata), a large QF solar developer. Mr. Morrison testified that the Regulatory Disallowance Clause created uncertainty that was a barrier to financing a QF project and asserted that investors were unwilling to "overlook the asserted right of DNCP to modify rates and collect a refund." Mr. Morrison cited to FERC's statement in Order No. 69 that "in order to be able to evaluate the financial feasibility of a [QF], an investor needs to be able to estimate, with reasonable certainty, the expected return on potential investment before the construction of a facility," and stated his belief that the Regulatory Disallowance Clause creates unnecessary uncertainty regarding the expected return on a QF investment, in violation of Order No. 69.Mr. Morrison also asserted that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA, and testified that Strata has not developed solar facilities in the Company's service territory because of the Regulatory Disallowance Clause.

DNCP responded to Mr. Stuebe's affidavit and Mr. Morrison's direct testimony through the rebuttal testimony of Mr. Robert J. Trexler. Mr. Trexler testified that the Regulatory Disallowance Clause did not give DNCP or this Commission the right to disallow recovery of or adjust avoided costs payments made pursuant to Schedule 19-FP, that DNCP would contest any such disallowance, and that Article 6 does not give the Company the right to seek a Disallowance Order. Mr. Trexler also testified that DNCP believes that QFs should receive full payments under a PPA and that DNCP should receive full rate recovery of those payments. He explained that Article 6 simply recognized that neither the Company nor a QF can control the actions of a regulatory body, and allocates the burdens of a Disallowance Order equitably if such an order is issued and held to be lawful.

DNCP noted that the Regulatory Disallowance Clause is not a new addition to DNCP's Schedule 19 contracts. The Commission has approved standard Schedule 19 PPAs containing a clause similar to the Regulatory Disallowance Clause since at least 1997. *See, e.g., In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 1996*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 23, Docket No. E-100, Sub 79 (June 19, 1997) (approving the standard contracts proposed by DNCP as reasonable). Moreover, DNCP pointed out that the Commission recently ruled on the appropriateness of the Regulatory Disallowance Clause, in the last biennial proceeding, where it held that, based on the record in that proceeding, DNCP's inclusion of the same Regulatory Disallowance Clause in its Schedule 19-DRR PPA was "reasonable and should be allowed."*See* 2010 Biennial Order at 22.

DNCP argued that inclusion of the Regulatory Disallowance Clause is reasonable and necessary as a matter of fundamental fairness. The Company's purchase of energy and capacity from QFs is not optional. Currently, pursuant to PURPA, and the rules, regulations and orders of this Commission, the VSCC and FERC, the Company has a mandatory obligation to purchase energy and capacity from QFs of 20 MW or less at the

Company's avoided cost.[3] Without the Regulatory Disallowance Clause, if there were a Disallowance Order, the Company would be required to continue making full payments to the QF but would not be compensated for the portion of those payments in excess of the Disallowance Order amount. The Company believes there is no principled reason that the burden of the disallowance of legally compelled payments should be borne by the Company and its shareholders.

DNCP also explained that the fact that the Commission will have expressly approved the Schedule 19 rates in this proceeding does not have any bearing on the need for a Regulatory Disallowance Clause, though it does tend to lessen the risk of a Disallowance Order. DNCP cited precedent for the proposition that a regulatory commission cannot revise avoided cost rates that it has previously reviewed and approved.[4] However, DNCP stated that the possibility still exists that avoided cost rates approved by one regulatory body could be rejected by another regulatory. Further, the Company noted that in North Carolina, avoided cost rates for QFs larger than five MW are not reviewed and approved by the Commission and therefore do not enjoy the relative assurance of Commission-approved rates. Accordingly, any decision by the Commission to require removal of Article 6 from the Schedule 19 PPAs would not and should not apply to contracts that are not eligible for Schedule 19 (e.g., those contracts pertaining to QFs larger than five MW).

DNCP stated that while it believed that the risk of a Disallowance Order is remote, DNCP cannot ignore the fact that in two instances, once by this Commission and

[3] *See Virginia Electric and Power Company*, 124 FERC ¶ 61,045 (2008) (relieving DNCP of its obligation to purchase energy and capacity from QFs with a net capacity of greater than 20 MW).
[4] *See, Freehold Cogeneration Associates v. Bd. of Regulatory Commissioners of New Jersey*, 44 F.3d 1178, 1194 (3d Cir. 1995), *cert. denied*, 516 U.S. 815 (1995).

once by the VSCC, DNCP has been denied ratepayer recovery of a portion of its payments to QFs.[5] For example, *Utilities Commission v. North Carolina Power* involved a situation in which the VSCC set long-term avoided rates for three Virginia QFs in an arbitration hearing. When DNCP sought recovery of the VSCC mandated avoided cost payments in its North Carolina rates, this Commission disallowed recovery of a portion of the avoided cost payments approved by the VSCC. The Commission's disallowance order was upheld by the North Carolina Supreme Court whereupon DNCP unsuccessfully sought a writ of certiorari from the United States Supreme Court, which was denied. Because of this Commission's disallowance, DNCP was not able to recover the full avoided cost payments it made to the QFs from its ratepayers. The burden of the disallowance fell solely on DNCP's shareholders. As discussed above, the Company believes that it is inequitable that the burden of the disallowance of payments that the DNCP is legally required to make pursuant to PURPA be borne by the Company and its shareholders. *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2012,* Transcript of Hearing held Oct. 29-30, 2013, Vol. 3, p. 275, line 7—p. 277, line 16 ("Hearing Transcript").

In specific response to Mr. Stuebe's affidavit, DNCP stated that two lenders do not constitute the universe of potential lenders or sources of financing to Ecoplexus' proposed facilities, and that it has entered into a number of QF contracts containing Article 6 in which the QFs have seemingly managed to finance their facilities. In

[5]*See Ex rel. Utilities Commission v. North Carolina Power*, 338 N.C. 412, 416, 450 S.E.2d 896, 898-899 (1994), *cert. denied*, 516 U.S. 1092 (1996); *Hopewell Cogeneration Limited Partnership v. State Corporation Commission*, 249 Va. 107, 118-119, 453 S.E.2d 277, 284 (1995), *cert. denied,* 516 U.S. 817 (1995).

addition, DNCP argued that neither PURPA nor this Commission require a utility to modify its avoided cost policies based on the demands of a QF's lenders.

With regard to Mr. Morrison's arguments regarding Order No. 69, DNCP agreed with Mr. Morrison's general proposition that a QF investor, like any other investor "needs to be able to estimate, with reasonable certainty, the expected return on potential investment before the construction of a facility." DNCP contended, however, that PURPA does not require that QF investors, unlike other investors, be entitled to absolute certainty of a return on their investment. Moreover, DNCP stated that an investor in a Schedule 19-FP QF has a "reasonable certainty" with respect to its investment, because under existing law and precedent, the possibility of a Regulatory Disallowance Order is remote. Finally, DNCP questioned why, if the QF and its lenders will not accept the remote but real risk of a Disallowance Order, should the entire risk be shifted to the utility and its shareholders, since the utility must comply with the legal mandate to purchase power from QFs, and must also comply with a Disallowance Order that is held to be lawful. DNCP argued that there is no principled reason or basis in PURPA for the Commission to impose the entire burden of a Disallowance Order on the Company and its shareholders under those circumstances.

DNCP disagreed with Mr. Morrison that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA. DNCP stated that, under the Schedule 19 PPA, a QF is entitled to receive fixed rates over the term of the PPA. Absent the occurrence of a breach of the PPA by the QF, the QF's entitlement to those rates would be affected only if there is a Disallowance Order that is found to be lawful after appeal by the Company and the QF.

To be found lawful, DNCP argued, a court would almost certainly have to find that a disallowance was not barred by 18 C.F.R. § 292.304(d)(2).

Finally, DNCP disagreed with Mr. Morrison's contention that the Regulatory Disallowance Clause discourages QF development in the Company's North Carolina service territory. In the last two years, DNCP has entered into five Schedule 19 contracts with QFs, of which three have entered commercial operation and two have started construction, and each of these contracts contained the Regulatory Disallowance Clause at issue in this proceeding. DNCP has also entered into a PPA with a 20 MW QF that also contains a provision similar to the Regulatory Disallowance Clause. Perhaps more significantly, as of the date of its witness Mr. Trexler's rebuttal testimony, at least 44 QF projects, representing over 370 MWs of nameplate capacity, have filed applications for CPCNs for facilities in DNCP's North Carolina service territory, nearly all of which are for solar facilities. *See* Rebuttal Testimony of Robert J. Trexler on Behalf of Dominion North Carolina Power at p. 11, lines 10-16 (Oct. 18, 2013); *see also* Exhibit RJT-1 to Trexler Rebuttal Testimony. In short, DNCP concluded, even with the inclusion of Article 6 in its Schedule 19 and non-Schedule 19 PPAs, there appears to be strong and active interest in the development of QFs in the Company's North Carolina service territory.

REG witness Morrison testified at the hearing that he had not reviewed and had no opinion on the comments made by Mr. Trexler in his rebuttal testimony. *See* Hearing Transcript, Vol. 2, p. 138, lines 5-12.On cross-examination, Mr. Morrison acknowledged that if a Schedule 19 PPA did not contain a Regulatory Disallowance Clause, in the event of a disallowance the QF would retain all of the benefits of its contract while the entire burden of the disallowance would be borne by DNCP and its shareholders. *See id.* at p. 128, line 4—p. 129, line 21.Mr. Morrison indicated that it was unlikely that he would change his position on the acceptability of the Regulatory Disallowance Clause even if DNCP offered to split the burden of a disallowance with a QF such that the QF would bear fifty percent of the burden of the disallowance and DNCP would bear fifty percent of the burden of the disallowance. *See id.* at p, 129, line 22—p. 130, line 17.

Mr. Morrison agreed that PURPA did not entitle a QF absolute certainty of return on its investment. *See id.* at p. 134, lines 17-24.Further, Mr. Morrison acknowledged that there were other risks associated with a QF project that investors could evaluate based on the probability of their occurrence, such as loss of QF status and failure to meet construction deadlines. *See id.* at p. 135, line 1—p. 138, line 4.

On cross-examination, Mr. Morrison agreed that the Regulatory Disallowance Clause did not give DNCP the unilateral right to change a QF contract absent a disallowance order by a regulatory body. He further agreed that if QF investors believed that the Regulatory Disallowance Clause gave DNCP the unilateral right to modify a Schedule 19 contract, the investors were operating under an incorrect assumption. He acknowledged that discussions between the Company and potential QF investors concerning how the Regulatory Disallowance Clause actually works might allay some of the concerns of those investors about the clause, but to his knowledge, his development group had not approached the Company about such discussions. *See id.* at p. 132, line 2—p. 134, line 9; p. 140, lines 6-12.

The Commission agrees with DNCP that PURPA does not entitle a QF developer to absolute certainty of a return of its investment. Based on the record in this proceeding, DNCP has demonstrated that the risk of a Disallowance Order is a remote risk, the probability of which can be evaluated by QF developers with reasonable certainty. While the risk of a Disallowance Order is remote, DNCP has also demonstrated that the risk is real. The Commission agrees with DNCP that because DNCP is legally obligated by PURPA to purchase the output of QFs, if a Disallowance Order is issued and found to be lawful, it would be inequitable for the burden of a Disallowance Order to be borne by the Company and its shareholders. In summary, the Commission finds that DNCP's inclusion of a regulatory disallowance clause in its standard Schedule 19 contracts continues to be reasonable and should be allowed.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

No party to this proceeding recommended a change with respect to the rates to be made available to QFs not eligible for the standard long-term levelized rates. The Commission concludes that DNCP should continue to be required to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations or, when explicitly approved by Commission Order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission. Under PURPA, a larger QF is just as entitled to full avoided costs as a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules was never intended to suggest otherwise.

The Commission has previously ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously available complaint process. The Commission concludes that the arbitration option should be preserved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Commission has repeatedly affirmed that the peaker method is appropriate for calculating avoided cost rates. For purposes of this proceeding, the Commission concludes that the peaker method is generally accepted and used by the electric utility industry and is reasonable for use in this proceeding. As discussed further in Discussion and Conclusions for Finding of Fact No. 10, based on the record in this proceeding, the Commission cannot find that a Value of Solar (VOS) analysis constitutes an acceptable alternative means of determining a utility's avoided costs pursuant to PURPA.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 AND 11

The evidence to support this finding of fact is contained in the Initial Comments of REG, the testimony of REG witness Mr. Don C. Reading, the Reply Comments of Public Staff, the testimony of DNCP witness Bruce E. Petrie, the testimony of NCSEA witness Mr. Karl Rábago, the Commission order and court decisions cited in this section, and the Stipulations of Settlement filed on October 29, 2013 between DNCP and Public Staff and on October 30, 2013 between DNCP and REG.

The Commission has traditionally used a PAF in calculating avoided capacity cost rates for utilities that use the peaker methodology. Until the 1996 avoided cost proceeding in Docket No. E-100, Sub 79, the Commission approved a PAF of 1.2 for the calculation of avoided cost rates for all QFs. In its Order approving avoided cost rates in that docket, the Commission approved a PAF of 2.0 for hydroelectric QFs with no storage capability and no other type of generation, which allows such QFs to recover their full capacity payments if they operate 50% of the on-peak hours. The 1.2 PAF used by the Commission in previous cases (for QFs other than run-of-the-river facilities) reflected the Commission's judgment that, if a unit is available 83% of the time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided costs.

In its Initial Comments, REG proposed that the tariff capacity rates for wind and solar projects also be based on a PAF of 2.0. REG relied primarily on language from the Commission's order in Docket No. E-100, Sub 106, where the Commission stated that:

> [t]he actual reason for using a 2.0 PAF for run-of-river hydro QFs has been that doing so allows them to receive the full capacity payments to which they are entitled while operating under the constraints created by their stream flows. As the Public Staff witnesses pointed out, using a 2.0 PAF places run-of-river hydro QFs on an equal footing with the run-of-river hydro generating facilities included in the rate base of the State's utilities, which are able to recover the full costs of these facilities. With respect to solar and wind QFs, however, this comparison has no relevance, because the State's utilities have no solar or wind facilities in rate base. On the other hand, the Commission agrees that solar and wind QFs, like run-of-river facilities, have no control over their energy source. This is a legitimate argument for treating them in the same manner as run-of-river hydro QFs.

In the Matter of Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2006, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 20, Docket No. E-100 Sub 106 (Dec. 19, 2007) ("2006 Biennial Order") (cited by *REG Initial Comments* at 7-8).

REG argued that solar and wind QFs, like run-of-river facilities, have no control over their energy sources, and no storage capability, and therefore should also receive a PAF of 2.0. REG further argued that a PAF of 2.0 for wind and solar QFs should be imposed because utilities recover their full capacity cost for utility units regardless of when their facilities produce power. Finally, REG claimed that FERC's 2010 and 2011 decisions regarding the avoided cost regime in California[6] support the increase in the PAF to 2.0 for wind and solar QFs.

In his prefiled direct testimony, REG's witness Mr. Don C. Reading reiterated the comments and arguments made by REG in support of a 2.0 PAF. In addition, Mr. Reading noted that (1) Senate Bill 3 (SB 3) has been in effect for five years, (2) 2012 was the first year that utilities were subject to an increase in the REPS requirement, and (3) SB 3 was not modified in the 2013-2014 legislative session.

In its reply comments, the Public Staff noted that in Docket No. E-100, Sub 106, the Commission observed that the passage of SB 3 created a renewable energy and efficiency portfolio standard (REPS) and "established strong state policy support for renewable energy sources . . . ." The Public Staff also stated that FERC's *CPUC* decisions are relevant given the requirements of SB 3. While not expressing a definitive position on the PAF issue in its filings in this proceeding, the Public Staff stated that it would be appropriate for the Commission to address the need for a solar-related PAF in an evidentiary hearing.

[6] *See California Public Utilities Commission***,** 132 FERC ¶ 61,047, *order granting clarification and dismissing reh'g,* 133 FERC ¶ 61,059 (2010) ("*CPUC Clarification Order*"), *order denying reh'g,* 134 FERC ¶ 61, 044 (2011) ("*CPUC*").

In its Comments, the NCSEA supported the REG position. In addition, NCSEA offered the prefiled direct testimony of Mr. Karl Rábago in support of an increased PAF of 2.0 for wind and solar QFs.

Mr. Rábago offered a review of "Value of Solar" (VOS) analyses as an "equitable" basis, in addition to the "legal" basis offered by REG, to support adoption of a 2.0 PAF. (As a long-term proposition, Mr. Rábago also proposed adopting a VOS analysis for purposes of determining avoided costs, at least as those costs relate to solar QFs.) As described by Mr. Rábago, a VOS is an evaluation of the costs and benefits of distributed solar generation. Mr. Rábago believes that the results of a VOS are a better indicator of the "full avoided costs" of distributed solar generation. Mr. Rábago's prefiled testimony noted that he did not perform a VOS for this proceeding or draw upon any North Carolina-specific VOS in his initial testimony. Subsequent to filing Mr. Rábago's initial testimony, NCSEA filed on October 18, 2013 a report by Crossborder Energy, dated October 18, 2013, that purported to evaluate "The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina." Mr. Rábago did not play any role in the compiling of the Crossborder report and testified that to his knowledge the report had not been peer reviewed. *See* Hearing Transcript, Vol. 3, p. 11, lines 1-12.

In its filings, DNCP disagreed with the proposal to extend the 2.0 PAF to wind and solar QFs, due to the fact that wind and solar generated energy is intermittent in nature, does not produce energy dependably over the super-peak hours, and is not dispatchable and controllable like a CT unit. DNCP argued that there is no logical reason to pay a premium capacity rate to new renewable resources that are not likely to generate reliably at the time of the Company's system peak load.

Explaining further why a PAF of 2.0 for a solar QF, specifically, is inappropriate, DNCP stated that, in one sense, solar generation is attractive because it can produce energy during sunny daytime hours when the aggregate customer demand is high. However, a utility plans for capacity additions based on its forecasted annual system peak load which, for DNCP, typically occurs sometime around 4 or 5 p.m. on a summer weekday. At that particular time, a solar QF, on average, is likely to produce only 20 to 40 percent of its maximum potential output. DNCP explained that, because of this mis-alignment and considering that solar panels are not functionally equivalent to a dispatchable CT, basing the capacity rate for solar QFs on the full cost of the peaker, plus requiring a PAF of 2.0, would result in the solar QF being paid for capacity that is not avoided by the Company. In recognition that capacity has value only to the extent that a generator can reliably operate during the critical summer peak hours, the PJM capacity market, for example, gives new solar resources a capacity credit of only 38% of their installed MW value. Under this approach, it would take 1,053 MW of new solar capacity for the utility to avoid having to build a new 400 MW CT plant. Stated in terms of the peaker method calculation, which uses the full cost of a peaker, a PAF of 1.2 recognizes this timing misalignment and results in a closer representation of DNCP's avoided cost.

With regard to wind QFs, DNCP argued that a PAF of 2.0 is inappropriate because, at the time of the system annual peak load, the expected generation from a 1 MW wind unit would be even less than the expected solar generation from a similarly sized unit. Wind potential is very site specific, but on average, at the time of the system peak load, a wind QF is likely to produce only 10 to 20 percent of its maximum potential output. Again, as an example, the PJM capacity market recognizes this disconnect by giving new wind resources capacity credit for only 13% of their installed MW value. As with solar QFs, paying a wind QF the full cost of the peaker plus requiring a PAF of 2.0 would result in overpayment to the QF for the capacity that is actually avoided. Also as with solar QFs, in light of the timing misalignment between system peak load and likely wind output and stated in terms of the peaker method calculation, which uses the full cost of a peaker, a PAF of 1.2 results in a closer representation of DNCP's avoided cost.

DNCP also argued that its ratepayers would bear additional costs with a PAF of 2.0 for solar and wind QFs, since adjusting the PAF from 1.2 to 2.0 for wind and solar QFs would increase the capacity rates to those QFs by approximately 66% - an increase that will be borne by customers – with no corresponding additional benefit to the Company or those customers. Specifically, this adjustment to the PAF would result in these customers bearing the burden of the Company paying a capacity rate to these QFs that exceeds its avoided capacity cost rate.

DNCP also testified that the inclusion of solar or wind generating facilities in a utility's rate base is not relevant to the appropriate PAF for solar or wind QFs. DNCP reiterated that, in this proceeding, the Commission is determining the avoided costs of the Company pursuant to PURPA, and that avoided costs under PURPA are not determined by reference to the retail rate base of an electric utility. DNCP continued that, likewise, in this proceeding the Commission is not determining the avoided costs of an individual solar or wind facility and noted that the "Commission has never indicated that the calculation of the incremental costs which the utility would have to incur but for a purchase from a particular QF should be based upon the same type of generating unit that that particular QF is proposing . . . ." *EP&S Order* at 6. The fact that a utility is able to recover the full costs of generating units included in its rate base that may not run at a 100% capacity factor is not relevant to the calculation of avoided costs. Unlike a QF, a utility must build sufficient generation to meet its system peak load and reserve requirements, in order to plan for load forecasting uncertainty and generator unplanned outages, including unavailability of QFs under contract to the Company.

In response to REG's argument that SB 3 justifies the increase of the PAF for solar and wind QFs to 2.0, DNCP disagreed, stating that, among other things, SB 3 established a REPS for North Carolina. The requirements of the REPS are specified in N.C. Gen. Stat. § 62-133.8, which requires that certain percentages of utilities' retail sales be met through renewable resources. In addition, beginning in 2018, at least two-tenths of a percent of the total electric power in kWh sold to retail customers by utilities must be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities that use solar hot water, solar absorption cooling, solar dehumidification, solar thermally driven refrigeration and solar industrial process heat. However, DNCP argued, notably, SB 3 does not mandate a rate for purchases from renewable energy facilities. Instead, it simply provides that if a utility is required to pay more than avoided costs to purchase power from such facilities in order to satisfy REPS requirements, the utility is entitled to recover these excess costs, to the extent they were reasonable and prudently incurred. The absence of any directive on rates in SB 3 is in stark contrast to N.C. Gen. Stat. § 62-156, which as the Commission stated in Docket No. E-100, Sub 106, formed a basis, in part, for the imposition of a PAF of 2.0 for run-of river QFs. That statute directed the Commission to encourage long-term contracts to increase the economic feasibility of hydro QFs and specifically spoke to the determination of avoided costs for hydro QFs.

DNCP stated further that there are other incentives to the development of renewable resources, state and federal tax incentives to encourage the development of renewable resources, and that renewable generators produce renewable energy certificates (RECs) that can be sold into the market. DNCP argued that, in fact, the REPS and other aspects of SB 3 and other state and federal incentives have encouraged the development of renewable resources in North Carolina. DNCP cited NCSEA for the fact that North Carolina's clean energy sector has grown substantially since the enactment of SB 3. DNCP concluded that an additional subsidy to solar and wind QFs in the form of an increased PAF is not necessary to encourage their development, since it appears that the multiple layers of governmental incentives are already providing sufficient encouragement to those QFs and other forms of renewable resources.

In response to arguments that FERC's decisions in the *CPUC* cases provide support for adoption of a 2.0 PAF for solar and wind QFs, DNCP argued that because of the differences between the avoided cost regime in North Carolina and the avoided cost regime in California on which the *CPUC* decisions were based, FERC's *CPUC* decisions do not provide meaningful guidance on the PAF issue in this case. DNCP explained that the *CPUC* case arose out of the set of California laws and regulations that essentially limited the pool of new supply options available to its utilities to combined cycle gas turbines, renewable energy, other non-carbon emitting resources and combined heat and power (CHP) facilities. As part of that effort, California legislators passed a law requiring California utilities to offer to enter into ten-year contracts with CHPs that met certain more stringent efficiency and emission standards, at prices set by the CPUC. The question for FERC in the *CPUC Clarification Order* was whether PURPA allowed the CPUC to create a multi-tiered avoided cost rate structure that calculated estimated avoided prices for purchases from CHP QFs discretely from estimated avoided cost prices for purchases from other QFs. FERC held that a multi-tiered avoided cost structure that takes into account a state imposed obligation that utilities purchase energy from particular sources for a long duration could be consistent with PURPA. FERC explained that, because in "determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration," the CPUC could account for actual procurement requirements and resulting costs imposed on utilities in California. *CPUC Clarification Order* at P 26. For example, it determined that "'if a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural gas-fired unit, for example, would not be a source 'able to sell' to that utility for the specified renewable resources segment of the utility's energy needs, and thus would not be relevant to determining avoided costs for that segment of the utility's energy needs.'" *Id*. at P 27. Thus, under the *CPUC Clarification Order,* if a state required that a utility purchase 10 percent of its energy needs from solar facilities, the state could also determine the avoided costs for that 10 percent segment based on the avoided costs of such facilities (i.e., the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from solar QFs, such utility would generate itself or purchase from other sources).

DNCP pointed out, however, that this Commission has not adopted a multi-tiered avoided cost regime where the avoided costs of solar QF or wind QFs are calculated separately (i.e., without regard to and excluding the costs of a CT) for purposes of a resource-type set aside. Nor is there any evidence in the record of this proceeding that would support the Commission's creation of such segmented avoided costs rates. Further, DNCP noted that in addition to the time associated with gathering such evidence, adoption of such a multi-tiered approach would require careful consideration of a number of issues, which would further prolong this proceeding. For example, once a utility has satisfied its procurement requirement for a specified energy source (e.g., solar), the Company believes that the utility would have no further capacity needs for solar resources and therefore no obligation to purchase any further capacity from solar QFs. The utility would, of course, retain its PURPA obligation to purchase energy from solar QFs. Due to the distinction between the context of the *CPUC* case and the PURPA implementation approach in North Carolina, DNCP argued that the *CPUC* decisions do not provide any meaningful guidance on the issues in this proceeding. Further, DNCP contended that, even were the Commission to decide that it is appropriate to adopt a multi-tiered avoided cost regime, there is no evidence in the record to support such an approach being adopted in this proceeding.

DNCP argued further that, if the Commission determines that a re-examination of its current PAF policy is needed, such an inquiry should include all QFs, including run-of-river hydro QFs, and should be based on an in-depth examination of the likely avoided capacity costs based on the actual operational and capacity characteristics of these types of facilities. The appropriate PAF should reflect both the availability and capability during the tariff defined on-peak hours, and also both the availability and capability of the QF resource at the time of the utility's system peak load. DNCP stated that there is not sufficient evidence in the record of this proceeding to make such a determination, and rather than further prolonging this proceeding, and the attendant uncertainty for both QFs and the Company, agreed with DEP and DEC that the issue should be examined in a separate proceeding or workshop.

In lieu of adjustment to the Commission's existing policy of applying a PAF of 1.2 to eligible QFs, Public Staff witness Kennie Ellis in his Direct Testimony suggested adoption of DEC's Option B as an alternative way to spread capacity credits over fewer on-peak hours, and recommended that the Commission consider requiring DEP and DNCP to offer a comparable Option B in addition to their traditionally calculated avoided capacity rates. Under this option, the designation of on-peak and off-peak hours would be modified to align with the periods corresponding to the times when a utility's customer demand and the cost of generation generally is the highest. The result is that the number of on-peak hours is reduced, and QFs with limited operating hours benefit since their output is mostly coincident with the utility's peak demands.

In the rebuttal testimony of DNCP witness Mr. Petrie, DNCP stated that it was not opposed to adding an Option B type rate offering, in addition to its existing rate offerings, so long as the PAF used in the Option B rate offering is 1.2. DNCP contended that the Option B on-peak hours definition is consistent with customers' current demand patterns, and covers those hours when the system is most likely to experience its peak load.DNCP noted, however, that as customer demand patterns change (for example, with increasing penetration of distributed solar generation), adjustments to the on-peak hours definition may be appropriate. If DNCP added an Option B type rate offering, and subsequently concludes that such a change is required, it would bring the issue to the Commission's attention in its biennial filings.

In response to Mr. Rábago's VOS discussion, DNCP argued that VOS is not an appropriate method for the Commission to determine avoided costs. DNCP reiterated that avoided costs are defined under PURPA as "the incremental *costs* to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." In contrast, DNCP argued, the VOS as described by Mr. Rábago provides compensation to QFs not only for the costs that are avoided by utilities but also for perceived benefits of solar QFs. These benefits include items such as "reputational community participation," recognition of financial risks associated with "future control regimes" and "societal benefits" such as job growth, and increased local tax revenues. DNCP pointed out that this Commission has consistently held that "uncertain and unquantifiable costs such as those associated with environmental externalities should not be taken into account in calculating avoided cost rates . . . ." 2006 Biennial Order at 23-24.

DNCP stated that, while some of the items mentioned by Mr. Rábago may have value to an individual or a locality (e.g., job growth associated with a solar facility or increased local tax revenues) or value to society generally, they are simply not costs that are avoided by a utility through the purchase of energy and capacity from a solar QF. DNCP, for instance, does not avoid any "reputational community participation costs" as a result of the purchase of energy and capacity from a QF. In sum, the types of value adders discussed by Mr. Rábago are not properly included in the calculation of avoided cost pursuant to PURPA. Other avenues exist for local, state and federal entities, if they choose, to compensate QFs for these types of intangible or unquantifiable benefits, as currently evidenced by the various tax benefits, renewable energy credits and other incentives for QFs that produce these sorts of benefits.

DNCP also noted that this Commission has provided guidance on the appropriateness of including compensation for compliance with future environmental control costs that supports not adopting a VOS analysis. DNCP cited the Commission's statement in Docket E-100, Sub-74 that:

> [U]tilities should not be required to include environmental compliance costs in their respective avoided cost calculations that are unknown or uncertain in nature for purposes of this proceeding. Quantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility.

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 1994, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 24, Docket No. E-100, Sub 74 (Jun. 23, 1995). DNCP also noted that in Docket No. E-100, Sub 106, the Commission rejected the arguments that avoided cost rates should include an allowance for general "environmental impacts that may be caused by generating plants," and held that under PURPA, rates paid to a QF must equal the monetary costs a utility avoids by obtaining power from a QF.2006 Biennial Order at 23-24 ("Environmental externality costs . . . cannot properly be included in calculating avoided costs.").

Finally, DNCP noted that Mr. Rábago included as Exhibit KRR-2 to his testimony a Rocky Mountain Institute report that summarized 15 VOS and other studies addressing distributed solar generation benefits and costs (the RMI Report). The executive summary of the RMI Report stated that

> Methods for identifying, assessing and quantifying the benefits and costs of [distributed photovoltaics] and other [distributed energy resources] are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees and pricing.

Exhibit KRR-2 at 5, "A Review of Solar PV Benefit and Cost Studies," 2nd Edition (Sept. 2013).

On October 29, 2013, DNCP and Public Staff filed a Stipulation of Settlement with respect to DNCP's proposed avoided capacity rates for Schedule 19-FP, and related issues, including the appropriate PAF for purposes of this proceeding (the DNCP-Public Staff Stipulation). On October 30, 2013, DNCP and REG filed a substantially similar Stipulation of Settlement (the DNCP-REG Stipulation).[7]Under paragraph 2 of the stipulations, DNCP, REG and the Public Staff agreed that:

a. DNCP's currently proposed capacity rates should be offered as Option A under DNCP's Schedule 19-FP.

b. DNCP will calculate and include in Schedule 19-FP an Option B with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by Duke Energy Carolinas, LLC in its currently effective Option B rates. DNCP will file such Option B for approval by the Commission in this proceeding. For the avoidance of doubt, the Stipulating Parties agree that such on-peak and off peak hours for summer and non- summer months shall be as follows:

[7]The remaining provisions of the DNCP-Public Staff Stipulation and the DNCP-REG Stipulation are discussed in the Discussion and Conclusions for Findings of Fact Nos. 13 and 14, below.

(i) The on-peak period hours for DNCP's Option B shall be those hours, Monday through Friday, beginning at 1 P.M. and ending at 9 P.M. during summer months (June 1 through September 30 for Option B) and beginning at 6 A.M. and ending at 1 P.M. during non-summer months (October 1 through May 31 for Option B).

(ii) The off-peak period hours for DNCP's Option B shall be all other weekday hours and all Saturday and Sunday hours. All hours for the following holidays shall be considered as off-peak: New Year's Day, Memorial Day, Good Friday, Independence Day, Labor Day, Thanksgiving Day, Day after Thanksgiving, and Christmas Day.

In consideration of the stipulation with regard to DNCP's institution of the foregoing Option B, DNCP and REG, and DNCP and Public Staff, agreed in their respective Stipulations of Settlement that the PAF under Schedule 19-FP for QFs that are not run-of-river hydro QFs should be 1.2 for purposes of this proceeding.DNCP and REG, and DNCP and Public Staff, also agreed in their respective Stipulations of Settlement that the agreement of the parties described above was without prejudice to any position that any might take with respect to PAF or analogous issues in any future proceeding.

NCSEA did not enter into a similar Stipulation with DNCP but did not express opposition to it at the hearing.

Based on the record in this proceeding, and in light of the DNCP-Public Staff Stipulation and the DNCP-REG Stipulation, the Commission concludes that it is appropriate to maintain in this proceeding the 1.2 PAF for renewable QFs other than run of river hydroelectric facilities. The Commission further finds that DNCP shall file modifications to Schedule 19-FP instituting Option B as provided in the stipulations of settlement.

Based on the record in this proceeding, the Commission cannot find that a VOS analysis constitutes an acceptable means of determining a utility's avoided costs pursuant to PURPA, and will not direct the utilities to perform such an analysis.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence to support this finding of fact is contained in the prefiled direct testimony of DNCP witness Bruce E. Petrie.

In addition to not accepting the proposal for a 2.0 PAF for wind and solar QFs, DNCP also argued that the Commission should impose an annual maximum or "cap" on capacity payments resulting from the application of a PAF in order to avoid the real possibility of payments to QFs in excess of the Company's avoided costs. As DNCP explained, the method of calculating hourly capacity rates is based on the annual total avoided cost for a peaker, which is converted to a levelized on-peak hourly ¢/kWh rate by application of the on-peak hours for each day, the capacity factor or PAF, and a discount rate. This method allows a QF to receive the full annual capacity payment available for a year if the QF produces 100% of its dependable capacity during 83.3% or 50% (equivalent to a PAF of 1.2 and 2.0 respectively) of the total on-peak hours in the calendar year. If a QF produces 100% of its dependable capacity for greater than 83% or

50%, as applicable, of the on-peak hours, the QF could earn more than 100% of full capacity payments. DNCP's proposed capacity payment cap would be calculated as follows: in any calendar year, the maximum annual capacity payments made to the QF would be no greater than the dependable or contracted capacity, multiplied by the annual capacity on-peak hours, and further multiplied by the applicable average on-peak capacity price (in cents per kilowatt-hour) divided by the applicable PAF (i.e., by 1.2 for a PAF of 1.2 or 2.0 for a PAF of 2.0). In the beginning and ending year of the QF's contract term, the hours referenced above would be prorated.

No party to this proceeding objected to DNCP's proposal for a cap on PAF-derived capacity rates.

Based on the record in this proceeding, the Commission concludes that an annual cap should be imposed on capacity payments resulting from application of a PAF in order to avoid the real possibility of payments to QFs in excess of the utilities' avoided costs. As explained by DNCP, this capacity payment cap shall be calculated as follows: in any calendar year, the maximum annual capacity payments made to the QF would be no greater than the dependable or contracted capacity, multiplied by the annual capacity on-peak hours, and further multiplied by the applicable average on-peak capacity price (in cents per kilowatt-hour) divided by the applicable PAF (i.e., by 1.2 for a PAF of 1.2 or 2.0 for a PAF of 2.0). In the beginning and ending year of the QF's contract term, the hours referenced above would be prorated.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence to support this finding of fact is contained in the prefiled direct and rebuttal testimony of DNCP witness Mr. Bruce E. Petrie, the Initial Statement and testimony of the Public Staff, the prefiled direct testimony of REG witness Mr. Don C. Reading, the Commission orders cited in this section, and the DNCP-Public Staff Stipulation and the DNCP-REG Stipulation.

In calculating its avoided capacity cost estimates for this proceeding, DNCP used the construction costs and fixed operating and maintenance costs of a combustion turbine (CT). In the context of the Commission's biennial avoided cost proceedings this methodology is commonly referred to as the "peaker method." As described by DNCP, under the peaker method, the development of the capacity rates starts with the estimated construction cost and annual fixed costs of a CT, in millions of dollars. From these capital expenditures, the annual revenue requirements, including financing costs, for the new CT are calculated. The annual revenue requirements are then converted to an economic carrying charge (ECC) rate in millions of dollars per year. The ECC rate escalates annually at an assumed rate of inflation. For rate schedules such as Schedule 19-FP, which provide for capacity payments during on-peak periods only, the annual costs (in millions of dollars) are then converted to the appropriate $/kWh capacity rates. The last step in implementing the peaker methodology as adopted in North Carolina is to adjust the $/kWh capacity rates by the Commission-prescribed PAF.

DNCP explained that the CT used in its analysis is a two-unit addition at an existing Company owned site and is assumed to be operational in 2013. The CT is 400 MW (summer rating) in size, with a book life of 36 years. The long term inflation rate was assumed to be 1.84% per year. DNCP provided the nominal installed cost of this unit, plus annual costs related to fixed O&M and natural gas pipeline firm transportation costs, in Mr. Petrie's prefiled direct and rebuttal testimony. DNCP selected a 400 MW size for the CT based on the Company's 2012 Integrated Resource Plan filed with the Commission on August 31, 2012 in Docket No. E-100, Sub 137 (the 2012 IRP). Other inputs and assumptions used in the Company's avoided cost analysis for this proceeding were also consistent with the inputs and assumptions in its 2012 IRP. The in-service date of the CT used in the analysis was assumed to be January 1, 2013, because as DNCP explained the proposed Schedule 19-FP tariff is available to any QF that would become operational during the biennial period January 2013 through December 2014.

In its Initial Comments and direct testimony of Mr. John Hinton, the Public Staff asserted that DNCP should include land costs in its estimated installed CT cost, noting that in Docket No. E-100, Sub 87, the Commission required the Company to include land costs in its avoided capacity calculation. REG witness Mr. Reading also argued that land costs should be included in DNCP's installed CT cost estimates.

In his direct and rebuttal testimony, DNCP witness Mr. Petrie argued that the Commission's holding in Docket E-100, Sub 87 was not applicable to this proceeding. Mr. Petrie noted that in Docket No. E-100, Sub 87, DNCP used the projected capital cost of the Ladysmith CT units 1-2 for its avoided capacity calculations. In that case, when the Public Staff pointed out that the Company's estimates did not include the cost of land, the Company agreed to add the cost of land because the Ladysmith site was a greenfield site (i.e., the Company would have to purchase land for the generating units). However, as the Commission noted in its order in that proceeding, the Company did not agree that inclusion of land costs was always appropriate:

> NC Power . . . agreed land costs should be included in the calculations in cases where land costs could actually be avoided. However, the [C]ompany pointed out that new capacity is sometimes added at existing sites where land costs cannot be avoided.

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2000, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 12, Docket No. E-100, Sub 87 (Apr. 6, 2001).

Because the Company had agreed to the Public Staff's request to include land costs in that proceeding, the Commission adopted "NC Power's agreement to include land costs in its capacity credits, and conclude[d] that NC Power should be required to include the capital costs of land in its calculation of capacity credits <u>for purposes of this proceeding</u>." *Id.* at 12-13 (emphasis added).

In the context of this proceeding, Mr. Petrie noted that the Company has multiple existing sites available to install the 800 MW of CTs identified in its 2012 IRP and would install those CTs on brownfield sites. Because the CTs will be installed on brownfield sites, the Company did not include any land or other greenfield related costs in its installed CT cost estimates. Because the Company would not incur any land costs associated with CTs on a brownfield site, DNCP argued the avoided land costs for such CTs are $0. The Company argued that requiring the Company to pay capacity rates that include an allowance for land costs that are not avoided will result in the Company paying more than its avoided costs for capacity in violation of PURPA. DNCP argued that this is exactly the circumstance that the Company described in Docket E-100, Sub 87: when new capacity will be added at existing sites, "land costs cannot be avoided."

In the DNCP-Public Staff Stipulation and the DNCP-REG Stipulation, DNCP and Public Staff or REG, as applicable, stipulated that DNCP's proposed installed CT cost per kW, inclusive of AFUDC, is a reasonable and appropriate installed cost per kW for purposes of calculating DNCP's avoided capacity rates in this proceeding. The parties also stipulated that the avoided capacity rates proposed by the Company are a reasonable and appropriate estimate of DNCP's avoided capacity costs for purposes of this proceeding. The foregoing stipulations were expressly conditioned on DNCP adopting Option B, as described in Discussion and Conclusions for Finding of Fact No. 11, above. DNCP and Public Staff or REG, as applicable, also agreed that their respective stipulations did not constitute an admission by any party that land or other greenfield related costs should or should not have been included in DNCP's calculation of its installed cost and was without prejudice to any position that a party to the stipulation may take with respect to that issue in any future proceeding.

NCSEA did not enter into a similar stipulation with DNCP but did not express opposition to it at the hearing.

Based on the record in this proceeding, the Commission concludes that the proposed resolution of the issues set forth in the DNCP-Public Staff Stipulation and the DNCP-REG Stipulation are reasonable and finds that DNCP's estimated installed CT costs as reflected in those agreements are reasonable for purposes of calculating DNCP's avoided capacity rates, and the avoided cost rates themselves should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence to support this finding of fact is contained in the DNCP-Public Staff Stipulation and the DNCP-REG Stipulation.

The DNCP-Public Staff Stipulation and the DNCP-REG Stipulation each state that the parties will discuss further the structure and availability of two-year variable energy and capacity rates. DNCP's Schedule 19-FP contains two-year variable energy rates,[8] but does not contain two-year variable capacity rates. The Commission finds that, as provided in the stipulations, the parties shall discuss further the need for and structure of two-year variable capacity rates.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 15

DNCP proposed to make the following changes to its existing Schedule 19-DRR that are also reflected in the proposed Schedule 19-FP and Schedule 19-LMP: (1) remove the requirement for a QF to provide a letter of credit; (2) add language stating that a QF's sale of power to the Company does not convey ownership of the renewable energy credits or green tags associated with the QF; and (3) revise the assignment language in the standard form contract to require the QF to reimburse the Company for the actual costs, up to a maximum cap of $10,000 per assignment, incurred by the Company in connection with an assignment. Except as discussed elsewhere in the body of this order, no party opposed the above proposed changes or the provisions of DNCP standard contracts.

The Commission finds that, subject to the modifications discussed elsewhere in this order, DNCP's proposed Schedule 19-DRR, Schedule 19-FP, Schedule 19-LMP and the associated standard contracts are reasonable and are approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DNCP shall offer long-term levelized capacity rates and energy rates for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying

[8] *See* Article VI of Schedule 19-FP as filed Aug. 15, 2013.

facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. DNCP shall offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

2. That DNCP may offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the following conditions: (a) any QF choosing to enter into a contract using the PJM market pricing method shall 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, after doing so, enter into a new two-, five-, ten-, or 15-year Schedule 19-FP contract, at its option, and (b) upon the request of a QF, DNCP shall calculate avoided cost payments using each method on a monthly basis for the next two years and provide the comparison to the requesting QF that is receiving payment under either of the Schedule 19-FP or Schedule 19-LMP. A QF may request such a comparison once every six months.

3. That DNCP shall provide a comparison of the peaker (Schedule 19-FP) method and the PJM market pricing (Schedule 19-LMP) method in the next biennial avoided cost proceeding. As part of this comparison, DNCP shall (a) file PJM prices

during each relevant summer season; (b) identify the five peak hours that were used in the SPPF; (c) file the PJM input data for each of the five coincident peak hours; and (d) file a comparison of the payments a QF would have received for one year, including the first full summer following the date of this Order, under the peaker method and under the PJM market pricing method, assuming various levels of hypothetical outages during the five coincident peak hours during the preceding summer.

4. That DNCP's proposal to close Schedule 19-DRR to new customers is reasonable and hereby approved.

5. That DNCP may continue to limit the availability of its Schedule 19 tariffs to otherwise eligible QFs that can make deliveries of power within the Biennial Period.

6. That DNCP may continue to include a regulatory disallowance clause in its standard contracts for purchases of energy and capacity from QFs.

7. That DNCP shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a Commission-recognized active solicitation underway, it shall offer QFs not eligible for the standard long-term levelized rates the options of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings or (2) contracting with the utility to sell power at negotiated rates. If the utility does not have a solicitation underway, any unresolved issues arising from such negotiations will be subject to arbitration by the Commission at the request of either the

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

8. That for purposes of this proceeding a PAF of 2.0 is maintained for hydroelectric facilities with no storage capability and no other type of generation, and a PAF of 1.2 is maintained for all other QFs.

9. That an annual cap shall apply to capacity payments resulting from application of a PAF, which annual cap shall be calculated as follows: in any calendar year, the maximum annual capacity payments made to the QF would be no greater than the dependable or contracted capacity, multiplied by the annual capacity on-peak hours, and further multiplied by the applicable average on-peak capacity price (in cents per kilowatt-hour) divided by the applicable PAF (i.e., by 1.2 for a PAF of 1.2 or 2.0 for a PAF of 2.0). In the beginning and ending year of the QF's contract term, the hours referenced above would be prorated.

10. That DNCP shall file modifications to Schedule 19-FP instituting Option B as provided in the stipulations of settlement.

11. That the estimated installed CT costs used by DNCP to calculate its avoided capacity costs are reasonable and hereby approved, and that the avoided cost rates proposed by DNCP based on those installed CT costs are reasonable and hereby approved.

12. That, subject to the modification discussed in this order, DNCP's revised Schedule 19-LMP, revised Schedule 19-DRR, and proposed Schedule 19-FP, and standard contract terms and conditions associated with these tariffs, are approved. DNCP shall file new versions of its rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. Those rate schedules and standard contracts should be allowed to go into effect ten days after they have been filed unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that ten-day period.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _____________, 2013.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount, Deputy Clerk