DUKE ENERGY®

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June 22, 2017

VIA ELECTRONIC FILING

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

Re: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Proposed Order
Docket No. E-100, Sub 148

Dear Ms. Jarvis:

Please find enclosed for filing in the above-referenced docket Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's (collectively, the "Companies") Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities. An electronic copy is being emailed to briefs@ncuc.net.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress
Associate General Counsel

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, in Docket No. E-100, Sub 148, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 22nd day of June, 2017.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	**DUKE ENERGY CAROLINAS, LLC'S**
Rates for Electric Utility Purchases from	)	**AND DUKE ENERGY PROGRESS, LLC'S**
Qualifying Facilities – 2016	)	**PROPOSED ORDER ESTABLISHING**
	)	**STANDARD RATES AND CONTRACT**
	)	**TERMS FOR QUALIFYING FACILITIES**

HEARD: Tuesday, February 21, 2017, at 9:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, April 18, 2017, at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, April 19, 2017, at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Thursday, April 20, 2017, at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Friday, April 21, 2017, at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

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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's (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under North Carolina General Statute (G.S. or Gen. Stat.) § 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 thereto by the FERC prescribe the responsibilities of the 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 the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. The relevant 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, the FERC delegated the implementation of these rules to State regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

The Commission has implemented 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 whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also results from 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 in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" as used in 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 22, 2016, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing* (Scheduling Order). Pursuant to the Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (collectively, DEC/DEP or the Companies), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP) (collectively with DEC and DEP, "the Utilities"), Western Carolina University (WCU), and New River Light and Power Company (New River) (collectively, the Utilities) were made parties to the proceeding. 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. The Commission established January 9, 2017, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings; February 15, 2017, as the deadline for reply comments; and March 15, 2017, as the deadline for proposed orders. The Scheduling Order also scheduled a public hearing for February 21, 2017, solely for the purpose of taking non-expert public witness testimony. Finally, the Scheduling Order required the Utilities to publish notice in newspapers having general circulation in their respective North Carolina service areas and submit affidavits of publication no later than the date of the hearing.

The following parties filed timely petitions to intervene that were granted by the Commission: The North Carolina Sustainable Energy Association (NCSEA); the Public Works Commission of the City of Fayetteville; Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Customers for Fair Utility Rates I, II, and III (CIGFUR); Southern Alliance for Clean Energy (SACE); Strata Solar, LLC (Strata Solar); North Carolina Pork Council; NTE Carolinas Solar, LLC (NTE); Cypress Creek Renewables, LLC (Cypress Creek); O2 EMC, LLC (O2 EMC); and North Carolina Electric Membership Corporation (NCEMC). Participation of the Public Staff is recognized pursuant to G.S. § 62-15(d) and Commission Rule R1-19(e). Pursuant to G.S. § 62-20, the North Carolina Attorney General's Office gave notice of intervention on April 11, 2017.

On October 21, 2016, DEC, DEP, and DNCP filed a Joint Motion requesting that the Commission extend the November 1, 2016 deadline for filing proposed avoided cost rates and standard form contracts by two weeks. The Commission granted the joint motion on October 27, 2016.

On November 15, 2016, DNCP filed Initial Comments and Exhibits along with avoided cost information, subsequently amended on December 16, 2016, to correct on-peak load numbers. On November 15, 2016, DEC and DEP filed a Joint Initial Statement and Exhibits, including a proposed procedural schedule with intervenors' testimony due March 14, 2017; Utilities' testimony due March 24, 2017; and an evidentiary hearing to begin April 4, 2017.

On November 28, 2016, WCU and New River jointly filed their proposed avoided cost rates.

On December 20, 2016, NCSEA filed a Motion to Strike as irrelevant to the proceeding certain materials in the Initial Statements of DEC, DEP, and DNCP. On January 4, 2017, DNCP, DEC, and DEP filed responses in opposition to NCSEA's Motion to Strike. The Commission subsequently issued an order denying NCSEA's motion on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule to allow the Public Staff and intervenors to conduct discovery on the testimony and to prepare responsive testimony. The Public Staff proposed that Utilities' testimony be due February 21, 2017; intervenors' testimony be due March 24, 2017; rebuttal testimony be due April 4, 2017; and an evidentiary hearing begin April 18, 2017.

On December 30, 2016, the Commission issued its *Order Scheduling Evidentiary Hearing and Amending Procedural Schedule* (Procedural Order), setting March 24, 2017, as the deadline for intervenors to file direct testimony and exhibits; setting April 4, 2017, as the deadline for Utilities to file rebuttal testimony; and scheduling the evidentiary hearing to begin at 9:30 a.m. on April 18, 2017. The Procedural Order also required that parties file proposed orders within 30 days of the issuance of the evidentiary hearing transcript.

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

On or before February 15, 2017, all Utilities filed Affidavits of Publication of the Notice of Hearing, and the public hearing was held on February 21, 2017, in the Commission's hearing room, as scheduled. Twelve witnesses gave testimony. In addition, over 1,000 consumer statements of position have been filed in this docket.

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

On March 22, 2017, NCSEA filed a Motion for Extension of Time, which the Commission granted on March 23, 2017, making intervenor testimony due March 28, 2017, and rebuttal testimony due April 7, 2017.

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

On April 6, 2017, DEC and DEP filed a Joint Motion for Extension of Time, which the Commission granted on April 6, 2017, making rebuttal testimony due April 10, 2017.

On April 10, 2017, DNCP filed the rebuttal testimony of witnesses Gaskill and Petrie; and DEC and DEP filed the rebuttal testimony of witnesses Bowman, Snider, Holeman, and Freeman.

On April 18, 2017, the evidentiary hearing was held as scheduled. DEC and DEP presented the testimony of witnesses Yates, Bowman, Snider, Holeman, and Freeman. DNCP presented the testimony of witnesses Gaskill and Petrie. Cypress Creek presented the testimony of witness McConnell. NCSEA presented the testimony of witnesses Harkrader and Johnson. SACE presented the testimony of witness Vitolo. The Public Staff presented the testimony of witnesses Hinton, Lucas, and Metz. The pre-filed testimony of those witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand.

On June 22, 2017, proposed orders were filed by the parties.

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

Based on the foregoing, all of the parties' comments and other filings, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. The recent rapid changes in economic and regulatory circumstances related to QF solar development since the Commission's last biennial review of standard avoided cost rates in Docket No. E-100, Sub 140 support now evolving North Carolina's PURPA implementation framework.

Eligibility Threshold and Standard Offer for Non-Hydrodynamic QFs

2. DEC and DEP should be required to offer standard contracts to non-hydroelectric QFs and hydroelectric QFs with storage capability contracting to sell 1 MW or less capacity.

3. DEC, DEP, and DNCP should offer QFs not eligible for the standard contract the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a Commission-recognized active solicitation underway, it should offer QFs not eligible for the standard offer the option of (a) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings, or (b) 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 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 arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard offer have the option of selling into the wholesale market. If the variable rate is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

4. DEC and DEP should be required to offer non-hydroelectric QFs and hydroelectric QFs with storage capability a contract term of 10 years with avoided capacity rates fixed and levelized over the term of the 10-year contract term and the option of: (1) avoided energy rates at Energy Rate Credits applicable under the Fixed Long-Term (10-year) option as filed with DEC's Schedule PP or DEP's Schedule PP-3, as appropriate, fixed until the next biennial proceeding, where they will be reset by the Commission as part of that proceeding or, at the election of the QF, (2) avoided energy rates at Energy Rate Credits applicable under the Fixed Long-Term (10-year) option as filed with DEC's Schedule PP or DEP's Schedule PP-3, as appropriate, fixed over the term of the 10-year standard offer.

Avoided Energy Rates

5. DEC's, DEP's, and DNCP's respective approaches to relying upon forward market prices and fundamental forecasts of future spot prices are reasonable and appropriate for use in calculating the Utilities' respective avoided energy rates approved in this proceeding.

Avoided Capacity Rates

6. DEC and DEP do not have a near-term need for capacity based on their 2016 Integrated Resource Plans ("IRPs"). DEC's 2016 IRP shows a need for capacity in 2023, and DEP's 2016 IRP shows a need for capacity in 2022.

7. The current economic and regulatory circumstances resulting from the rapid increase in solar generation in North Carolina has contributed to planned reserve margins in excess of DEC's and DEP's near-term capacity need, and warrants a departure from the Commission's traditional application of the peaker method, such that it is now

appropriate for DEC and DEP to make a capacity payment to QFs beginning only when additional capacity is needed on the system.

8. Allowing the Utilities to account for their relative respective needs for incremental generating capacity in calculating their avoided capacity rates will minimize the overpayment risk to ratepayers, while providing a reasonable level of financial compensation for QFs and send a more accurate price signal to the market.

9. Surging solar QF capacity and winter load uncertainty due to weather have driven the majority of the Companies' loss of load risk from summer to winter.

10. DEC's and DEP's proposed seasonal weighting of 80% winter/20% summer is supported by the evidence and is reasonable and appropriate for use in weighting capacity value between winter and summer.

11. A performance adjustment factor (PAF) of 1.05 should be utilized by DEC and DEP in their respective avoided capacity cost calculations for all QFs eligible for the DEC's Schedule PP or DEP's Schedule PP-3 standard offer rates.

<u>Legally Enforceable Obligation and Contracting Procedures</u>

12. The Utilities' experience since the Commission approved the current Notice of Commitment Form in Docket No. E-100, Sub 140 has been that QFs are seeking to establish a legally enforceable obligation (LEO) early in the QF development process at the time a certificate of public convenience and necessity (CPCN) is issued, often occurring when the QF developer: (i) has no concrete information on the feasibility, cost, or timing of interconnection; (ii) is not ready, willing, and able to sell power; and (iii) has not begun Power Purchase Agreement (PPA) negotiations with the utility. Accordingly, QFs are not making a meaningful, "legally enforceable" and

binding commitment to deliver energy and capacity to the utility over a specified term as contemplated by FERC's PURPA regulations.

13. Continued surging growth in utility-scale solar QFs since 2015 combined with the growing complexity of the interconnection study process and the increasing time required to construct system upgrades to interconnect QFs have caused DEC and DEP to become obligated for increasingly stale and inaccurate avoided cost rates at the time the QF begins delivering power.

14. Modifying the current Notice of Commitment Form to allow a QF to administratively establish a LEO 105 days after submitting a completed interconnection request does not result in the QF making a binding and unequivocal commitment to sell over a specified term, as the QF may walk away from the commitment and elect not to build the generator at all.

15. For larger QFs between 1 MW and 80 MW not eligible for the Utilities' standard offer tariffs, a legally enforceable commitment to sell should be meaningful and require the QF to be ready, willing, and able to make a binding and unequivocal commitment to deliver power in the future.

16. Subject to input from the Public Staff, DNCP, and other interested parties, the contracting procedures presented in DEC/DEP Witness Freeman's Rebuttal Exhibit No. 2 provide a reasonable and transparent procedure for larger QFs to control the timing of making a legally enforceable commitment to sell by negotiating a binding PPA with the utility. If a dispute should arise during PPA negotiations, the contracting procedures preserve the QF's current rights to petition the Commission to establish the date upon which the QF has established a non-contractual LEO through an arbitration proceeding.

17. Continuing to utilize an administratively-established Notice of Commitment Form for small QFs eligible for the Utilities' respective standard offer tariffs is just and reasonable for both customers and small QFs. This process would be efficient for small QFs and would not impose unjust and unreasonable avoided cost rates on customers because eligibility for the standard offer tariff avoided costs, terms, and conditions is only updated biennially.

Standard Offer PPA, Schedules PP, PP-3, PP-H, PP-H1, and Terms and Conditions

18. DEC's and DEP's proposed amendment to its standard offer terms and conditions to more clearly define the circumstances that are considered an "emergency condition" are reasonable and consistent with PURPA's provision for utility-initiated curtailment and discontinuance of purchases from QFs during system emergencies.

19. Once DEC/DEP have finalized non-discriminatory system emergency curtailment operating procedures, DEC/DEP should file the operating procedures with the Commission.

20. In its December 31, 2014 *Order Setting Avoided Cost Input Parameters* in Docket No. E-100, Sub 140, the Commission approved the June 24, 2014 Stipulation of Settlement among DEC, DEP, and the NC Hydro Group (Hydro Stipulation). The Hydro Stipulation provided that because of the state policy supporting small hydroelectric facilities and the relatively small and finite amount of small hydro capacity in the state, DEC and DEP would continue to use a 2.0 PAF to calculate the avoided cost rates for small hydro QFs of 5 MW and less (small hydro facilities) and that those small hydro facilities otherwise eligible for power purchase contacts with DEC and DEP would have the option of contract terms of 5, 10, and 15 years.

21. DEP's Schedule PPH-1 and DEC's Schedule PP-H as filed in this Docket are consistent with the terms and conditions of the Hydro Stipulation and are approved.

22. DEC/DEP's proposal to clarify their Schedule PP and PP-3, respectively, standard offer terms and conditions to preclude transfer and/or assignment of a standard offer PPA to a person or entity that owns another QF within one-half mile and is a party to another standard offer PPA is reasonable. A developer electing to acquire a QF in this circumstance must enter into a negotiated PPA with the utility.

Solar-Specific Rate

23. DEC/DEP's generic avoided energy and capacity rates are reasonable for purposes of establishing rates available to all small QFs eligible for the DEC/DEP standard offers, and a solar-specific adjustment to the off-peak energy rates that would isolate only one potential benefit of solar generation is not appropriate.

24. Factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity may be considered in establishing avoided cost rates for purchases from solar QFs not eligible for the Utilities' standard offer tariffs.

Competitive Bid Process

25. The Commission recognizes DEC's and DEP's request to initiate a competitive procurement stakeholder process to promote more sustainable and cost effective procurement of QF solar and other resources; however, the Commission is not inclined to open a new proceeding at this time, absent express direction from the General Assembly. DEC and DEP may formally petition the Commission to initiate such a

proceeding if future legislative action does not establish a new competitive procurement framework or the Commission may do so on its own motion.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 1

The evidence supporting this Finding of Fact is found in DEC/DEP's Joint Initial Statement and DNCP's Initial Comments, the testimony and exhibits of DEC/DEP Witnesses Yates, Bowman, Snider, and Holeman, the testimony of DNCP Witnesses Gaskill and Petrie, and the testimony of Public Staff Witnesses Hinton and Metz.

DEC/DEP Witness Yates testified that North Carolina is now at a critical crossroads regarding the integration, development, and customer costs of renewable generation, specifically QF solar generation, under PURPA. (Tr. Vol. 2 at 23). As of 2016, 60% of all installed PURPA solar projects in the entire United States are located in North Carolina, as North Carolina has "significantly encouraged" solar development under PURPA compared to its peer states. Witness Yates testified that the existing policies that led to this unconstrained growth in PURPA solar have also created a distorted solar marketplace that has resulted in artificially high costs being passed on to North Carolina residents, businesses, and industries, while potentially degrading operation of the Companies' electric systems. (Tr. Vol. 2 at 25-26).

DEC/DEP Witness Bowman testified regarding the PURPA regulatory scheme, emphasizing that Congress assigned implementation of PURPA to State Commissions that are best suited to consider and balance PURPA's goals with the economic and regulatory circumstances that vary from State to State and utility to utility. (Tr. Vol. 2 at 314). She described how North Carolina has evolved its implementation of PURPA over time as economic and regulatory circumstances have changed, including adjusting the standard offer eligibility threshold as well as the technologies eligible for the longer-term 10- and 15-year standard offer contracts.' Witness Bowman explained that the Commission has balanced the interest of QFs, the utilities, and customers through the State's PURPA standard offer implementation, recognizing that the overpayment risk to customers historically has been relatively small as QFs entitled to long-term rates were of limited number and size. (Tr. Vol. 2 at 315-17). Since 2005, however, the State's implementation of PURPA has remained relatively unchanged. Witness Bowman argued that recent rapidly changing economic and regulatory circumstances – specifically the surging growth of utility-scale QF solar in North Carolina – is now driving the need for comprehensive review of the Commission's PURPA policies. (Tr. Vol. 2 at 318-320).

Witness Bowman highlighted the dramatic growth in utility-scale solar over the past few years, with approximately 1,100 MW of third-party QF solar now installed in DEP and 500 MW installed in DEC. She also noted that an additional approximately 4,900 MW of third-party QF solar capacity (approximately 3,800 MW in DEP and 1,100 MW in DEC) are already in development and are requesting to interconnect and sell power to DEC and DEP. (Tr. Vol. 2 at 322-23). Witness Bowman also testified that PURPA is now the predominant driver of the continued surging solar development in North Carolina, as the State's Renewable Energy Tax Credit has now expired and DEP and DEC have also increasingly achieved long-term compliance with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") policy. (Tr. Vol. 2 at 325-27). She also noted that additional PURPA solar is not helping to meet DEC's and DEP's future REPS requirements. (Tr. Vol. 2 at 328).

Witness Bowman also explained why North Carolina is experiencing significantly greater PURPA growth than other states in the Southeast and throughout the country. She testified that the price level and term of avoided cost rates calculated under the Commission's historic PURPA polices, the low threshold to establish a LEO to sell QF power, as well as the current longer fixed terms for PURPA standard contracts for generators up to 5 MW are more favorable than other jurisdictions and has made North Carolina the fastest growing solar development marketplace in the Southeast and a leader in distributed utility-scale solar deployment nationally. (Tr. Vol. 2 at 328). She pointed out that Section 210(m) of PURPA, as enacted by the Energy Policy Act of 2005 (EPACT 2005), provided for termination of the PURPA must purchase obligation for utilities in organized markets and regional transmission organizations where QFs have non-discriminatory access to competitive wholesale energy and capacity markets. (Tr. Vol. 2 at 331). Witness Bowman also explained that other states in the Southeast have simply not adopted PURPA implementation policies as favorable to QFs as North Carolina's policies. Additionally, other jurisdictions around the country with significant PURPA development have recently taken steps to adjust their PURPA standard offer implementation, largely in response to significant growth of intermittent wind and solar QF generation that was increasingly causing PURPA over-supply and growing operational challenges. (Tr. Vol. 2 at 332-33). She explained that continuing the State's current PURPA policies may cause even greater interest in selling QF solar power under the current PURPA regime and significantly increase the overpayment risk for customers as QFs are no longer of limited size and number. (Tr. Vol. 2 at 333-34).

Witness Bowman also testified that broader purpose of the State's energy policies under the Public Utilities Act – to assure the delivery of reliable and least cost electricity to citizens and businesses of the State – should be considered in the Commission's assessment of the public interest under PURPA. Further, as the State's renewable energy resource mix is now increasingly being driven by variable and intermittent PURPA solar, the broader purpose of enacting REPS – to integrate a diverse and cost-effective mix of renewables and demand side resources to reliably serve customers – should also be considered in the Commission's assessment of the public interest under PURPA. (Tr. Vol. 2 at 335).

DEC/DEP Witness Snider testified to the significant long-term financial obligations now imposed on DEC/DEP's customers as a result of the recent surging QF solar growth under the Commission's current PURPA policies. Specifically, he explained that DEC/DEP's estimated long-term fixed purchase power obligation for the 1,600 MW of installed solar QFs as of year-end 2016 is approximately $2.9 billion dollars over the remaining 12-14 year terms of these agreements. He also testified that if these contracts were valued at the most recently filed avoided cost rates, they would have a value of only $1.9 billion, resulting in a potential long-term overpayment of approximately $l.0 billion by customers compared to DEC/DEP's' current calculation of its avoided cost rates in this proceeding. Witness Snider also testified that it is critical for the Commission to appreciate that customers' current financial obligation and exposure to overpayment risk could increase significantly in the future, as approximately an additional 1,100 MW of solar QFs under 5 MW have established LEOs under the Commission's current policy.''

DEC/DEP Witness Holeman testified to his recent experience and the growing operational concerns, reliability risks, and North American Electric Reliability Corporation (NERC) compliance challenges of integrating significant additional QF solar into the DEP and DEC Balancing Authority Areas (BAAs). He explained that DEP and DEC are independent Balancing Authorities (BAs) and must independently balance generation resources, unscheduled QF energy injections, and load demand in real-time, which is essential to providing reliable firm native load service, maintaining compliance with mandatory reliability standards, and achieving reliable bulk electric system operations across the Eastern Interconnection. (Tr. Vol. 2 at 60-62). Witness Holeman extensively described DEC/DEP's growing operational experience over the past 18 months with rapidly growing levels of installed PURPA solar, and highlighted the future challenges to reliable system operations, based on significant additional PURPA solar proposed to be installed over the next few years. (Tr. Vol. 2 at 66-67).

Witness Holeman testified that solar QFs are making "unscheduled" and "unconstrained" energy injections into the BA, outside of the Security Constrained Unit Commitment process, such that balancing the system is becoming increasingly volatile due to large and uncertain swings in the unscheduled and unconstrained solar QF energy injections. (Tr. Vol. 2 at 67-69). He explained how growing injections of unscheduled QF solar is requiring DEP to increasingly manage the Security Constrained Unit Commitment of its network generating resources at their lowest reliable operating limit or "LROL," which is the minimum operating level necessary to reliably provide frequency regulation and load-following resource availability to meet the evening peak as well as the next morning's peak demands. (Tr. Vol. 2 at 67-69). Witness Holeman presented figures and testimony analyzing how solar QFs' non-summer energy production between 10 a.m. and 3 p.m. is not coincident with DEP's and DEC's load shape and is increasingly requiring steep down-ramping of network resources (as well as causing operationally excess energy to meet the LROL) during the late morning. After solar production peaks during the mid-day and then declines in the afternoon, DEP is increasingly experiencing deficit energy situations requiring steep ramping up of network resources to meet evening peak loads. (Tr. Vol. 2 at 71-73). Witness Holeman also testified that the variability, volatility, and intermittency of QF solar energy production is causing DEP system operators to have limited operational situational awareness over the performance of these generators intra-day (caused by intermittency of solar production) and day-ahead (caused by variability of solar production) and is also requiring increasingly steep ramping of the BA's load-following network resources. (Tr. Vol. 2 at 76-79).

Witness Holeman also testified that DEP is now experiencing "operationally excess energy" with some regularity during an increasing number of days and hours throughout the year, including 105 hours in 2016 and already an additional 71 hours on 19 days during the first month and a half of 2017. Witness Holeman also forecasted that continued growth in installed QF solar capacity will significantly increase operationally excess energy in the DEP BA to 370 gigawatt hours per year by 2022. (Tr. Vol. 2 at 80-82). Witness Holeman also explained how the growing levels of operationally excess energy caused by the increasing levels of solar QFs will continue to put the DEP BA at risk of violating the mandatory NERC BAL reliability standards. (Tr. Vol. 2 at 84-92).

DNCP Witness Gaskill similarly testified that the landscape of QF development in DNCP's North Carolina service area has changed significantly since the 2014 avoided cost case and suggested that it is imperative for the Commission to reconsider its PURPA implementation to adapt to those changing circumstances. (Tr. Vol. 5 at 134). Witness Gaskill explained that the speed and magnitude of continued solar QF development since the 2014 Sub 140 avoided cost case has exceeded all expectations. He then described how the influx of distributed solar generation onto DNCP's North Carolina system is now adversely impacting system operations and is causing DNCP and its customers to pay far in excess of the Company's avoided costs for QF output. (Tr. Vol. 5 at 135-36). Witness Gaskill testified that DNCP has now contracted for 500 MW of QF solar, which is a significant increase from the 58 MW of contracted solar in February 2014. Further, 680 MW of QFs have now either executed PPAs or established LEOs, which is well above DNCP's average North Carolina on-peak load of approximately 518 MW in 2015. (Tr. Vol. 5 at 138). He also explained how the majority of DNCP's North Carolina distribution circuits have now reached a point of solar DG saturation. (Tr. Vol. 5 at 139). Witness Gaskill testified that these circumstances show that prior avoided cost policies designed to encourage QF development are now burdening customers and should be reconsidered. (Tr. Vol. 5 at 139).

DNCP Witness Petrie testified that for the approximately 650 MW of solar QFs that established LEOs since 2012, the Company is committed to approximately $100 million per year of PPA payments for the next 15 years, totaling an estimated $1.4 billion. He explained this obligation significantly exceeds the current and projected market value of these contracts by approximately $381 million, which means that DNCP and its customers are obligated to pay $381 million more under these contracts than the Company's actual avoided costs for energy and capacity in relation to these QFs. (Tr. Vol. 5 at 212-13).

Public Staff Witness Hinton testified to the tremendous level of solar QF development over the past five years in North Carolina, totaling approximately 2,000 MW installed and approximately 7,000 MW of additional solar QFs proposing to interconnect and sell power to DEC, DEP, and DNCP. (Tr. Vol. 8 at 21-22, 139). He also testified that this significant growth of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers, suggesting that the sheer volume of QF projects currently being developed in North Carolina calls into question FERC's premise in its *Order No. 69*[1] that future over-estimations and under-estimations of fixed long-term avoided costs would "balance out" over time. (Tr. Vol. 8 at 23). He also explained how this higher penetration of solar QF resources is posing operational and technical challenges for the utilities in meeting their obligation to provide safe, reliable, and economic service to ratepayers. (Tr. Vol. 8 at 23). Witness Hinton further explained that the pace of QF solar development is now exceeding load growth experienced by the utilities." (Tr. Vol. 8 at 22-23).

<u>Discussion and Conclusion</u>

Section 210 of PURPA established a program of cooperative federalism under which Congress directed FERC to establish rules "necessary to encourage cogeneration and small power production," including rules requiring utilities to purchase electricity

[1] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, 45 Fed. Reg. 12,214 at 12,224 (Feb. 1980), accessible at https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders/order-69-and-erratum.pdf ("*Order No. 69*").

from qualifying cogeneration and small power production facilities.[2] Under this cooperative federalism scheme, the Commission is responsible for implementing PURPA in North Carolina in a manner consistent with FERC's regulations.[3] Specific to the "must purchase" obligation, PURPA and FERC regulations require that rates for purchase from QFs must be "just and reasonable to electric consumers of the utility and in the public interest, and shall not discriminate against [QFs]."[4] Within these regulatory parameters, State Commissions are afforded latitude and flexibility in determining State PURPA policies as the States are best suited to consider and balance PURPA's goals with the "economic and regulatory circumstances [that] vary from State to State and utility to utility." *Order No. 69*, 45 Fed. Reg. at 12,231; *see also FERC v. Mississippi*, 456 U.S. 742, 751 (1982) (holding that cooperative federalism provides States the authority to "enact and administer their own regulatory programs, structured to meet their own particular needs" so long as the programs are consistent with minimum Federal standards (internal citations omitted).

As recognized by DEC/DEP, the Commission has a long history of evolving its implementation of PURPA in North Carolina in a manner intended to achieve the public interest, be just and reasonable to customers, and non-discriminatory to QFs. *See, e.g.*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at pp. 7-12, Docket No. E-100, Sub 96 (Oct. 23, 2003) (discussing the history of the Commission's consideration of long-term levelized rates in biennial avoided cost dockets). In each biennial proceeding, the Commission evaluates current economic and regulatory conditions and determines whether changed circumstances justify changes in

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2 16 U.S.C. § 824a-3(f).
3 16 U.S.C. § 824a-3(h).
4 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(1) (internal punctuation omitted).

avoided cost rates and/or other aspects of PURPA implementation in North Carolina. *See Order Denying Motion* at 3-4 Docket No. E-100, Sub 148 (Jan. 18, 2017); *see also Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 140 (Dec. 17, 2015) ("Sub 140 Phase II Order") ("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, balancing the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other").

In the 2012 biennial avoided cost proceeding, the Commission first identified the need to evaluate the potentially disruptive implications, both positive and negative, of the changing utility-scale solar landscape that was beginning to take shape in North Carolina. *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 31, Docket No. E-100, Sub 136 (Feb. 21, 2014). The Commission initiated Phase I of the 2014 Sub 140 (Sub 140 Phase I) proceeding to consider whether changes in North Carolina's implementation of PURPA were necessary and appropriate at that time, specifically including evaluation of the methodology historically relied upon to calculate avoided energy and capacity rates. The Utilities and intervening parties advocated for a number of changes to PURPA implementation in Sub 140. However, after extensive proceedings, the Commission's *Order Setting Avoided Cost Input Parameters* largely maintained the pre-existing PURPA implementation framework that had existed in North Carolina since at least 2007 when the North Carolina REPS was enacted. *Order Setting Avoided Cost Input Parameters,* Docket No. E-100, Sub 140 (Dec. 31, 2014) ("*Sub 140 Phase I Order*"). In balancing the costs, benefits, and risks to customers and QFs, the

Commission's decision to continue its pre-existing policies, including the 5 MW eligibility threshold, the 15-year fixed long-term standard offer, and the existing PAF was in larger part based upon a determination that widespread QF development was occurring under the existing framework without adverse impacts to utility ratepayers. *Sub 140 Phase I Order*, at 22, 56.

The Utilities and the Public Staff have presented extensive testimony highlighting a number of growing concerns that have either recently arisen or have become more significant as a result of continuing the pre-existing regulatory framework in Sub 140.

First, the evidence presented by DEC/DEP is uncontroverted that approximately 60% of solar QF development nationally is occurring under North Carolina's implementation of PURPA as of 2016. More robust PURPA-driven utility-scale solar QF development is now occurring in North Carolina than in any other jurisdiction in the southeast and throughout the country. Public Staff Witness Hinton similarly suggested the volume of solar QF development in North Carolina today is unparalleled with significantly more installed solar than other states across the country. (Tr. Vol. 8 at 23, 140). The record shows that installed solar has increased most dramatically in DEP over the past three years, nearly tripling from approximately 397 MW installed in 2014 to over 1,100 MW by year-end 2016 with an additional 3,800 MW in development. (Tr. Vol. 2 at 321). DNCP has also experienced significant additional QF solar growth since 2014, with avoided cost PPA commitments increasing from 58 MW of contracted solar in February 2014 to over 500 MW of QF solar under contract as of early 2017. The Utilities each emphasize that the speed and magnitude of continued solar QF development since the 2014 Sub 140 avoided cost case has exceeded all expectations.

Second, the Utilities have also all testified that as solar QFs entering into long-term fixed contracts are no longer of limited number and size, increasingly unjust and unreasonable purchase obligations have been imposed on their customers that are in excess of the Utilities' current avoided costs. DEC/DEP Witness Snider calculated that the long-term over-payment risk for its customers likely exceeds approximately $1 billion (especially in light of over 1,000 MW of additional QF solar projects with Sub 136 and Sub 140 LEOs), while DNCP Witness Petrie calculated that the long-term over-payment risk was approximately $381 million for its customers. Public Staff Witness Hinton also questioned the continued validity of FERC's presumption in Order No. 69 that, in the long-term, over-estimations and under-estimations of fixed avoided cost obligations would even out in light of the sheer volume of QF solar development now taking place in North Carolina. (Tr. Vol. 8 at 23).

Third, the Utilities' have presented uncontroverted testimony in this proceeding regarding increasing system operations challenges that are beginning to arise as these significant numbers of QF solar generators are now installed and how this growth is projected to increase in the near future. DEP/DEC Witness Yates testified that the Companies have gained significantly greater experience over the past 18 months with the real operational impacts of the surging development of PURPA-driven utility scale solar generation on the DEP and DEC systems and emphasized that this proceeding represents DEC's and DEP's first opportunity in a biennial avoided cost proceeding to inform the Commission regarding the detrimental impacts to the DEP system after approximately 1,000 MW of variable, non-dispatchable and non-curtailed utility-scale solar generation has come online – overwhelmingly in 5 MW increments on rural distribution feeders in

Eastern North Carolina. (Tr. Vol. 2 at 28). DEC/DEP Witness Holeman extensively testified to his first-hand experience with the growing system operations concerns, reliability risks, and NERC compliance challenges that are beginning to arise, and emphasized that solar QF penetration in the DEP BA will soon be at or greater than 2,200 MW – functionally, making these intermittent facilities the largest aggregate generator on the DEP BA. (Tr. Vol. 2 at 100). Witness Holeman explains that a diversity of generating resources on a system creates a balanced portfolio with lower concentrations of operating characteristics and risks, while high concentrations of a single type of resource, particularly an intermittent resource, such as solar QFs, create imbalance in the portfolio and higher operating risks due to its generating characteristics. (Tr. Vol. 2 at 75). Public Staff Witness Metz also identifies that continued growth in unconstrained and non-dispatchable generation will only serve to exacerbate the current system challenges facing DEP. (Tr. Vol. 8 at 119). DNCP Witness Gaskill similarly identifies that the influx of distributed solar generation onto DNCP's North Carolina distribution system is now adversely impacting system operations. (Tr. Vol. 5 at 140).

Fourth, the Commission recognizes DEC/DEP Witness Bowman's testimony that significant additional QF solar growth will largely not be beneficial to those Utilities in meeting the requirements of North Carolina's REPS policy.[5] In the 2014 Sub 140 and prior proceedings, the Commission has highlighted the complementary policy objectives and mandates of the North Carolina REPS as a rationale for continuing the significant encouragement of QFs under North Carolina's preexisting PURPA implementation framework. *See, e.g., Sub 140 Phase I Order* at 20 (highlighting that G.S. 62-133.8(d)

[5] While this issue was not addressed by DNCP, the Commission notes that DNCP has unique flexibility to use out-of-state RECs for REPS general obligation and set-aside compliance pursuant to G.S. § 62-133.8(b)(2)(e).

mandates that the terms of any contract entered into between an electric power supplier and a new solar electric facility for REPS purposes "[s]hall be of sufficient length to stimulate development of solar energy"). The Commission also questions whether the current PURPA-driven, increasingly solar-only, renewables environment in North Carolina is meeting the State's policy objectives of diversifying the resources used to reliably meet the energy needs of consumers in the State. G.S. 62-2(a)(10)a.

Based on the record in this proceeding, the Commission agrees with the Utilities and the Public Staff that economic and regulatory circumstances have changed significantly since the Sub 140 proceeding. The Commission finds and concludes that the Commission's prior finding in Sub 140 that widespread QF development was occurring under the existing framework without adverse impacts to utility ratepayers is no longer accurate, and that the public interest now requires the Commission to evolve North Carolina's implementation of PURPA in a number of respects. In this Order, the Commission is exercising the discretion and the latitude afforded by PURPA and FERC's regulations to ensure a more appropriate balance is struck between encouraging QF development, on the one hand, and protecting utility ratepayers from undue risks and excess costs on the other.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 2-3

The evidence supporting these findings of fact is found in the DEC/DEP Joint Initial Statement, the direct and rebuttal testimony of DEC/DEP Witnesses Bowman, Snider, and Freeman, the direct and rebuttal testimony of DNCP Witness Gaskill, the testimony of Public Staff Witness Hinton, Cypress Creek Witness McConnell, NCSEA Witnesses Strunk, Johnson, and Harkrader, and SACE Witness Vitolo.

In their Joint Initial Statement and the direct testimony of DEC/DEP Witness Bowman, the Companies argued that it was appropriate and justified at this time to lower the capacity eligibility limit for standard avoided cost rates from 5 MW to 1 MW for all QFs, except small “”hydro QFs. Witness Bowman testified that, in *Order No. 69*, the FERC recognized that although standard “one-size-fits all” avoided cost rates cannot account for the differences between QFs of various sizes and types, smaller QFs could be challenged by the transactional costs of negotiating individualized rates with utilities. (Tr. Vol. 2 at 337-38). The FERC balanced those concerns by requiring states implementing PURPA to make standard rates and terms available to QFs with a design capacity of 100 kW and smaller. Witness Bowman noted that the FERC also allowed states to put into effect standard rates for purchases from QFs with a design capacity above 100 kW. She explained that at least 20 states currently have standard rates that are limited to QFs less than 100 kW, while utilities in at least 33 states have eligibility caps at or under 5 MW. Witness Bowman also emphasized that the Companies were not recommending that the Commission adopt the FERC minimum of 100 kW as an eligibility threshold in this proceeding. (Tr. Vol. 2 at 338-39; Tr. Vol. 5 at 43).

Witness Bowman then recounted the Commission’s policies on the PURPA standard tariff eligibility, highlighting that a 5 MW eligibility threshold was first established in 1985 when the small power production industry was nascent. The 5 MW standard offer eligibility criteria was intended to encourage the development of QFs that, at that time, may not have had the resources, experience, or expertise to negotiate with a utility. (Tr. Vol. 2 at 339-340). She next described the current surge of solar QF development in North Carolina by describing how the 5 MW eligibility threshold had impacted the North Carolina solar market and DEC/DEP's customers. With respect to development of the North Carolina QF solar market, Witness Bowman testified that in the last five years, distribution-level utility-scale solar generation development around the 5 MW standard offer had exploded in North Carolina, particularly when compared with the rest of the United States. She explained how solar developers "disaggregate" potentially larger and more cost-effective solar projects to meet the 5 MW standard contract threshold, resulting in ongoing challenges in managing the interconnection of these generators to rural distribution circuits. Witness Bowman also described how the 5 MW threshold had become a highly attractive development business model for sophisticated and well-capitalized entities from around the country to take advantage of the guaranteed, long-term fixed rates of the standard contract by obtaining LEOs on multiple 5 MW and less solar facilities. She concluded that the 5 MW threshold had served its purpose of encouraging the development of QFs, particularly solar QFs, in North Carolina and should now be evolved. (Tr. Vol. 2 at 339-345).

With respect to the 5 MW eligibility threshold impact on DEC/DEP's customers, Witness Bowman testified that hundreds of standard contract solar projects between 1 MW and 5 MW had obtained LEOs in North Carolina, resulting in significant long-term financial commitments on behalf of DEC's and DEP's customers. She explained these long-term contractual purchase obligations are also at rates well in excess of DEC/DEP's current system incremental or "avoided" costs. Since March 2015, when the Companies filed their previous avoided cost rates, approximately 300 projects between 4 MW and 5 MW had obtained CPCNs, thereby potentially establishing LEOs under rates based on inputs to avoided cost calculations made two years ago. These QFs have been able to "lock in" standard, long-term fixed rates for likely the next 15 years. During these lengthy intervals, factors affecting the purchasing utility's avoided costs, such as fuel costs, environmental regulations, and capacity needs, can change dramatically, affecting the utility's actual avoided costs. (Tr. Vol. 2 at 342-43).

Witness Bowman next explained why a 1 MW eligibility threshold was appropriate and justified at this time, based on the current economic and regulatory circumstances. First, she noted that a 1 MW threshold is a reasonable proxy to differentiate between small QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial purposes by residential and commercial customers on the one hand, and larger sophisticated commercial enterprises and power generation developers in the business of owning or operating power generation facilities on the other. Second, she testified that the Companies' net metering tariffs are similarly available to customer-generation with a capacity of up to 1 MW in size. Third, she further testified that the FERC did not require QFs below 1 MW to self-certify as QFs. Finally, she explained that DEC/DEP's recent experience was that 1 MW solar projects were more likely to pass the Section 3 Fast Track interconnection study process, allowing both the standardized PPA and Interconnection Agreement to be obtained in a more streamlined fashion. (Tr. Vol. 2 at 345).

Witness Bowman also testified that the proposed 1 MW eligibility threshold would result in integrating solar in a more well-planned and coordinated manner, while better protecting customers from paying rates above avoided costs. In support, she cited the Commission's *Order on Clarification* in Docket No. E-100, Sub 140, in which the Commission had required the utilities to use the most up-to-date data for determining inputs to avoided cost rates for QFs that were eligible for negotiated, as opposed to standard, avoided cost rates. Witness Bowman also recalled that the Commission had previously issued orders in avoided cost proceedings on what factors should be considered in bilateral negotiations between the utilities and QFs. (Tr. Vol. 2 at 347). Aligning the avoided cost rates paid to QFs more closely with the utility's avoided costs at the time of the purchase meets PURPA's objective of ensuring customers remain indifferent between purchasing utility generation and purchases from QFs at the utility's avoided costs. Moreover, as Witness Bowman testified, it protects both customers and QFs in periods of rising and declining energy costs. (Tr. Vol. 2 at 346-47).

Witness Bowman also testified that QFs with a nameplate capacity in excess of 1 MW were still entitled to sell power to the utilities at avoided cost rates. These larger QFs would receive avoided cost rates though bilateral negotiations with the purchasing utility and not through the standard offer. She acknowledged that in the most recent avoided cost case, the Commission had declined to approve the Utilities' request to reduce the eligibility threshold to 100 kW, in part based on allegations by QF developers that the Companies' PPA negotiation process was protracted and difficult. Witness Bowman reported, however, that since that decision in 2014, the Companies had gained greater experience in negotiating PPAs with larger QFs greater than 5 MW. Witness Bowman relayed that DEC/DEP had negotiated more than 22 PURPA-only PPAs with large QFs since 2014, with 10 of these PPAs being negotiated since January 1, 2016. She noted that, of these 10, three were with the same developer, and many are with developers that are owner/developers of 5 MW or less QFs that avail themselves of the standard offer. Producing monthly avoided cost calculations for negotiated PPAs has become routine, and the negotiation process has become more standardized. Based on this experience, Witness Bowman concluded that the Companies were sufficiently prepared to efficiently negotiate PPAs in good faith with QFs larger than 1 MW. (Tr. Vol. 2 at 348-49).

DNCP also recommended that the Commission reduce the threshold for eligibility for the standard offer from the current 5 MW to 1 MW. DNCP Witness Gaskill testified that the 5 MW projects in DNCP's North Carolina service territory were also being developed by large, national developers with broad portfolios of renewable generation, access to complex financing, and experience in PPA negotiations. He related that, of DNCP's North Carolina QF contracts, 60 of the 72 PPAs with QFs are standard contracts for projects 5 MW and less. Of those 60 contracts, 55 were developed by only seven different developers. (Tr. Vol. 5 at 148).

Witness Gaskill agreed that standard rates and contracts for all QFs should be limited to projects with 1 MW of nameplate capacity. Witness Gaskill testified that lowering the eligibility threshold would allow more QFs to enter into negotiated contracts, instead of standard ones, which would result in three benefits: (i) avoided cost would better align with the QF's LEO; (ii) rates and terms could be customized to the specific project and location; and (iii) additional customer protections can be included in the negotiated contracts. Witness Gaskill noted that under the current framework, projects that establish a LEO late in the two years between avoided cost updates receive rates based on avoided cost determinations that were often four to five years old by the time the projects commence commercial operation. In contrast, Witness Gaskill noted that DNCP calculates projected avoided costs for QFs that do not qualify for standard offer rates, based on the more up-to-date data available at the time the QF establishes a LEO. This approach allows the rates that customers pay to better align with the current market conditions, including gas and power market prices. (Tr. Vol. 5 at 144-45). DNCP Witness Gaskill also testified that reducing the threshold to 1 MW still provides the opportunity for standard contracts for truly small projects, while helping to ensure that payments to larger projects more closely align with ratepayer's actual avoided costs. (Tr. Vol. 5 at 147).

The Public Staff supported the Utilities' proposal to reduce the eligibility threshold from 5 MW to 1 MW. Public Staff Witness Hinton testified that in previous avoided cost proceedings, the Public Staff had supported maintaining the 5 MW threshold as an "appropriate balancing point" between encouraging QF development on the one hand and protecting ratepayers from the risk of overpayments and stranded costs on the other. (Tr. Vol. 8 at 55-56). Circumstances in recent years, however, have caused the Public Staff to reconsider its prior position and to now support the Utilities' proposed reduction in the standard offer eligibility threshold. Witness Hinton highlighted the large number of facilities between 4 MW and 5 MW that had filed CPCNs over the past four years in support of the Public Staff's position. He acknowledged that this significant growth in facilities under which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers. He further agreed that the higher penetration of these resources posed operational and technical challenges to the Utilities in fulfilling their obligations to provide safe, reliable, and economic service to ratepayers. (Tr. Vol. 8 at 57). Therefore, Witness Hinton recommended that the Commission reduce the current eligibility threshold to better reflect the conditions in the QF marketplace and to better protect ratepayers from the risk of overpayment. (Tr. Vol. 8 at 58).

The Public Staff likewise recommended that the threshold for eligibility for the standard offer be 1 MW. In so recommending, Witness Hinton testified that the 1 MW threshold reflected regulatory precedent, citing the Commission's net metering proceedings, which established 1 MW as the maximum size of a facility approved to net-meter, as well as the FERC's requirement that QFs below 1 MW do not have to self-certify. Witness Hinton additionally cited practical reasons for the 1 MW threshold, agreeing with Witness Bowman that facilities 1 MW and below were more likely to pass the Fast Track interconnection study process than projects between 1 MW and 2 MW. (Tr. Vol. 8 at 59-60).

Witness Hinton further testified that QFs greater than 1 MW had three options remaining for obtaining full avoided cost rates for selling their power to the Utilities: (i) participating in a Commission-recognized competitive procurement process; (ii) free and open negotiations with the utility; and (iii) selling "as available" energy (but not capacity). He noted that if the utility does not have a Commission-approved active solicitation underway, any unresolved issues arising during a negotiation should be subject to arbitration by the Commission. (Tr. Vol. 8 at 60-61). Witness Hinton testified that the Public Staff still believed that the negotiation process posed challenges to QFs, but he acknowledged that QFs were negotiating and executing non-standard PPAs in order to maximize economies of scale and available interconnection capacity. (Tr. Vol. 8 at 60-61) Witness Hinton recommended that, if the Commission approved a lower eligibility threshold, streamlining and improving the negotiation process would be necessary. Witness Hinton stated that the Public Staff generally agreed with the contracting procedures set forth in DEC/DEP Witness Freeman's testimony including, specific timeframes for the exchange of information and responses; use of standardized contracting forms with clear delineation of changes or points of negotiation, indicative pricing for a sufficient period of time to allow QFs to evaluate the viability of its project and seek financing, the opportunity for either party to seek informal resolution of disputes or arbitrations with the Commission. (Tr. Vol. 8 at 62-63).

Apart from the Public Staff, the other intervenors opposed, to varying degrees, lowering the eligibility threshold from 5 MW to 1 MW. Cypress Creek Witness McConnell testified that it would make financing such projects more challenging. He indicated that the only way to make most financings work with a 5 MW threshold was to group them into portfolios to create critical mass for debt and tax equity investors. With a 1 MW limit, the portfolio size would become unwieldy due to the number of projects. (Tr. Vol. 6 at 117-120). On cross examination, Witness McConnell confirmed, however, that Cypress Creek was moving away from 5 MW projects toward larger negotiated projects. (Tr. Vol. 6 at 122).

SACE Witness Vitolo gave several reasons why he opposed lowering the threshold. He first stated that it would result in more lengthy, bilateral negotiations between QFs and the Utilities. He testified that the bilateral negotiations can take up to 25 hours of staff effort for uncontested PPAs for DEC and DEP. He argued that QFs must expend considerable effort in these negotiations and a power imbalance exists between the QF and the utility. A standard contract offers substantial benefits because the QF uses fewer resources in contract negotiations and the developer can benefit from a "significant" reduction in contract negotiation risk, expense, and delays. He next contended that reducing the standard offer threshold would result in QFs foregoing economies of scale. (Tr. Vol. 7 at 26-27). Witness Vitolo stated that to the extent that QF developers' limits are associated with access to capital or ability to procure solar PV hardware, the developer may simply develop more small projects to build out a portfolio that in the aggregate total a targeted capacity. An increase in projects would then result in an increase in the number of interconnection studies the utility must perform and in the number of simultaneous bilateral negotiations, requiring considerable effort by each counterparty. Witness Vitolo recommended that the Commission maintain its current policy as decided in its *Sub 140 Phase I Order*. (Tr. Vol. 7 at 28-30).

NCSEA Witnesses Johnson and Harkrader also opposed reducing the eligibility threshold to 1 MW. Witness Harkrader indicated that the current standard offer was a key to the success of the solar industry in North Carolina and that she had concerns about being able to negotiate with the Utilities if the threshold for the standard offer were lowered to 1 MW. (Tr. Vol. 7 at 380). Although Witness Johnson characterized the Utilities' proposal as "not as troubling" to him as some of the Utilities' other proposals, he raised similar concerns to Witness Vitolo regarding the increase in projects moving through the interconnection queues and the increases in costs to QFs and the Utilities. Instead of the 1 MW threshold, Witness Johnson recommended that the Commission consider adopting perhaps a 3.75 MW or 4 MW threshold to allow the Commission to see how the market reacted. (Tr. Vol. 7 at 328-29).

In her rebuttal testimony, Witness Bowman responded to the testimony opposing the reduction in the eligibility threshold from 5 MW to 1 MW. She noted that SACE

Witness Vitolo's testimony did not reference at all the tremendous surge of solar QFs at around the 5 MW level in North Carolina, which was one of the primary drivers of the Companies' proposal. She also disagreed with his assertion that adjusting the threshold will lead to solar QFs foregoing economies of scale to build smaller projects eligible for the 1 MW standard offer. Witness Bowman explained that the "disaggregation" of larger, more cost-effective, projects to smaller 5 MW ones has created ongoing challenges for DEC and DEP to manage the interconnection of these generators to rural circuits, especially on DEP's increasingly saturated distribution system. In contrast, the 1 MW threshold would better differentiate between the relatively small projects and the utility-scale solar projects. Furthermore, in response to Witness Vitolo's argument that maintaining the 5 MW threshold would result in lower costs overall because it would allow QF developers to retain economies of scale associated with developing a 5 MW project, Witness Bowman noted that the "lower costs" referred to would benefit solar QF developers and not the Utilities' customers. (Tr. Vol. 2 at 386-87).

Witness Bowman also refuted Witness Vitolo's contention that a significant power imbalance exists between QFs and Utilities in their PPA negotiations. She reaffirmed her direct testimony that utility-scale QFs are no longer being developed by small, fledging developers, highlighting that six large power generation developers, including Cypress Creek Renewables, Strata Solar, and ESA Renewables, accounted for more than 65% of the Companies' combined interconnection queues between 1 MW and 5 MW. (Tr. Vol. 2 at 388). She also rebutted Witness Vitolo's assertion that QFs' negotiations with DEC/DEP for a PPA can take months. She noted that, under the current Notice of Commitment Form approved by the Commission in its *Sub 140 Phase*

II Order, QFs larger than 5 MW have up to six months to execute a PPA after DEC or DEP submit it for signature. Witness Bowman testified that large QFs sometimes wait until that six month period is expiring to execute a PPA, adding to the apparent length of time between the LEO date and execution date of PPAs. (Tr. Vol. 2 at 388-390).

Witness Bowman next elaborated on the Companies' intention to further streamline and standardize the PPA negotiation process as discussed by Public Staff Witness Hinton in his direct testimony. She referenced 'DEC/DEP Witness Freeman's testimony proposing contracting procedures to foster transparency and efficiency in the PPA negotiation process with QFs, and posited that these procedures could be implemented quickly after input from the Public Staff and other interested parties after the Commission issues a final order in this proceeding. Witness Bowman reaffirmed the Companies' intent to continue to negotiate in good faith and follow FERC and Commission guidance in negotiating PPAs with QFs larger than 1 MW. She again cited the Commission's *Order on Clarification* issued in Phase I of the Sub 140 proceeding as directing DEC and DEP to use the most up-to-date data to determine inputs for negotiated rates. She noted that the Order on Clarification also instructed that any party was free to identify specific characteristics of a particular QF that merit consideration in the calculation of negotiated avoided cost rates. Witness Bowman specifically explained that the Companies believed that inclusion of ancillary generation costs or other solar integration costs in the calculations of avoided cost rates for QFs ineligible for the standard offer was appropriate under this FERC and Commission guidance for calculating avoided costs rates. She also testified that QFs may always request to review the inputs of DEC's and DEP's calculations of avoided costs, and that a QF may file a complaint or arbitration at the Commission if the QF disagrees with the inputs to the utility's avoided cost calculation or otherwise believe the Companies are not negotiating in good faith. (Tr. Vol. 2 at 390-95).

On cross-examination by NCSEA, Witnesses Bowman and Freeman provided further details on how DEC/DEP intend to negotiate with QFs larger than 1 MW. Witness Freeman indicated that the Companies have developed more standardized terms and conditions for large QFs, which would ease the process of negotiations. Witness Freeman declined, however, to support requiring Commission approval of changes to the standardized large QF PPA. He argued that doing so could overburden the negotiation process by requiring approval every time the Companies determine that a change to the standard terms and conditions for large QFs is needed. Witness Freeman added that the Companies had successfully negotiated over 20 such negotiated contracts with large QF developers. (Tr. Vol. 4 at 33).

DNCP Witness Gaskill also countered claims from NCSEA, SACE, and Cypress Creek witnesses that lowering the eligibility threshold will impact QFs' ability to obtain financing. He noted that QF developers in North Carolina tend to be large solar developers with large portfolios of generation projects in this State and elsewhere. He countered Witness Vitolo's assertion that an imbalance in power exists in the negotiated contracts because, with few exceptions, the negotiations of large QF contracts include relatively little dispute on the rates themselves, as they are calculated at the time of the LEO. (Tr. Vol. 5 at 174-78).

In response to questions from Chairman Finley, Witnesses Bowman and Freeman testified about the negotiations between the Companies and QFs over 1 MW. Witnesses

Bowman and Freeman agreed with Chairman Finley that a complaint or arbitration proceeding before the Commission between DEC or DEP and a QF negotiating a PPA could involve many disparate issues, including the minimum length of a PPA and each individual QF's ability to obtain financing. (Tr. Vol. 5 at 77-79). Witness Bowman further responded that DEC/DEP did not intend for complaints or arbitrations before the Commission to increase as a result of changing the current standard offer eligibility, and they testified that the number of QFs seeking PPAs could possibly decrease, as developers develop fewer larger facilities instead of more smaller ones to take advantage of economies of scale. (Tr. Vol. 5 at 121-22). Witness Bowman also confirmed in response to a question from Commissioner Finley and on redirect that the Companies did not object to the Commission establishing a formal or informal proceeding to resolve concerns and set expectations on how the Companies would negotiate avoided cost rates for QFs going forward. (Tr. Vol. 2 at 394-95; Tr. Vol. 5 at 79-81, 121-23).

Discussion and Conclusions

Based on the record in this proceeding, the Commission concludes that it is appropriate and justified, especially in light of the surge of 5 MW QFs in North Carolina and the resulting impacts on the Utilities and their customers as described in the testimony, to lower the threshold for eligibility for the standard offer from 5 MW to 1 MW.

Over the past 35 years, the Commission has exercised this flexibility in setting North Carolina's PURPA policies. Prior to 1985, standard avoided cost tariffs were available to all QFs of up to 80 MW for Duke Power and Carolina Power and Light Company and DNCP's standard offer was capped at 100 kW, due to the significant development of cogeneration and small power production facilities in DNCP's service territory in the early eighties. In 1985, the Commission established the 5 MW eligibility limit for the Utilities. In balancing the interests of QFs, the utilities, and customers, the Commission adopted the 5 MW standard because the default risks associated with such smaller QFs were "relatively small in terms of dollar exposure and impact on supply" when compared to larger QF projects and because, at that time, these smaller QF projects would "probably not have the resources or the expertise to negotiate a contract with a utility if these standard options were not available." *Order Establishing Levelized Rates for Cogenerated Power and Maintaining Interconnection and Wheeling Policies* at 12, Docket No. E-100, Sub 41A (Jan. 22, 1985). The Commission most recently reviewed the eligibility threshold in the Sub 140, Phase I proceeding. In that proceeding, the Commission declined to reduce the eligibility threshold to 100 kW based on concerns that development of solar facilities outside the standard tariff remained challenging. *Sub 140 Phase I Order* at 20.

As the record in this proceeding demonstrates, however, the economic and regulatory justifications for the 5 MW threshold have changed dramatically in recent years including since the recent Sub 140 proceeding. No party disputed that the number of 5 MW QF solar facilities requesting CPCNs has grown tremendously in North Carolina over the last five years or that North Carolina had become a national leader in distributed utility-scale solar development since 2014. Public Staff Witness Hinton specifically testified to the recent tremendous growth in 5 MW solar QFs since 2013, presenting a chart showing that the Commission has approved CPCNs over 1,000 QF generators between 1 MW and 5 MW since 2013, with approximately 750 of these QFs generators at or just below 5 MW. (Tr. Vol. 8 at 57). In short, and based on the foregoing, the Commission concludes that the 5 MW threshold has served its intended purpose of encouraging the development of QFs, particularly solar QFs, in North Carolina.

Moreover, no party effectively refuted that the 5 MW threshold for the standard offer has become a business model for larger, sophisticated, well-capitalized developers, instead of providing a means for unsophisticated "mom and pop" developers that lack the experience and capital to negotiate effectively with the Utilities. In fact, testimony from Witnesses Bowman and Gaskill demonstrated that larger, more sophisticated and well-capitalized developers are often the counterparties in both negotiated and standard offer QF PPAs. As Cypress Creek Witness McConnell testified, Cypress Creek, a solar developer, constructor, and operator, headquartered in California, operates in numerous states across the country. (Tr. Vol. 6 at 126). Witness McConnell described how, from a business perspective, Cypress Creek can maximize its profits in North Carolina from either developing 5 MW facilities in North Carolina or by bundling 5 MW or less projects into portfolios to solicit equity investors. (Tr. Vol. 6 at 117-157; DEC/DEP McConnell Cross Examination Exhibit No. 4). The Commission did not establish the 5 MW threshold, however, to benefit large, sophisticated solar developers or so that they could break up or "disaggregate" large solar deployments into small, individual projects simply to get higher pricing and better financing. Additionally, the Commission notes that the testimony tended to show that the Utilities have "standardized" much of the negotiations with respect to the non-standard offers. Thus, the Commission concludes that the solar marketplace in North Carolina is no longer nascent, but instead mature and robust. Accordingly, utility-scale QF developers above 1 MW operating in North Carolina no longer require the 5 MW threshold to shield them from negotiating with the Utilities.

The Commission further agrees with Witness Bowman's and Witness Gaskill's testimony that, based on this level of utility-scale solar development in North Carolina, continued significant encouragement of solar development through the 5 MW threshold is increasingly imposing unjust and unreasonable PURPA obligations on the Utilities' customers. From a system operations perspective, no party disputed that increasingly higher penetrations of these utility-scale solar generators on the Utilities' distribution systems poses operational and technical challenges to the Utilities in their obligation to provide safe, reliable, and economic service to ratepayers. Further, as Witness Bowman noted, QFs up to 5 MW have been eligible for the standard offer, which has allowed them to "lock in" to standard, long-term rates for up to 15 years. The Utilities' testimony shows that the biennially-reestablished standard offer rates have become "stale" as declining commodity costs have resulted in increasing deviation from the Utilities' actual avoided costs. By allowing for the negotiation of PPAs with utility-scale QFs above 1 MW, the Utilities may instead use the more up-to-date data and take into account the specific characteristics of the QF. This is entirely consistent with PURPA's requirement that customers pay no more than the Utilities' actual avoided costs.

The Commission further agrees with the Utilities and the Public Staff that the 1 MW threshold is appropriate and justified at this time. First, a threshold of 1 MW aligns more with the majority of the states, which will likely help to balance out the outsized development of 5 MW solar QFs in North Carolina. Second, the evidence shows that a 1 MW eligibility threshold represents a reasonable proxy to differentiate between utility-scale developer-sponsored solar and smaller QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial reasons. Third, the 1 MW threshold aligns with both the Commission's net metering tariffs and the FERC's QF self-certification rules. Fourth, the record shows that QFs 1 MW or below were more likely to pass the Fast Track Process than those between 1 MW and 2 MW, which should allay concerns that the reduction of the eligibility threshold from 5 MW to 1 MW will result in even more crowded interconnection study queues. Thus, the Commission concludes that lowering the standard offer tariff eligibility threshold to 1 MW effectively rebalances the two competing objectives under PURPA. It enables the Utilities to negotiate more precise avoided cost rates using the most up-to-date data and taking the specific characteristics of the particular QF into consideration, which mitigates the risk of overpayment. At the same time, it ensures the standard tariff rates are available to smaller "non-utility scale" QFs that may not be able to justify the cost and effort of negotiating with the Utilities.

Additionally, the Commission finds SACE Witness Vitolo's argument against the reduction of the eligibility threshold unavailing. First and most significantly, Witness Vitolo urges the Commission to simply maintain the status quo with respect to its PURPA implementation, without even acknowledging the tremendous growth in solar QFs in North Carolina or the accompanying risk of customers overpaying for PURPA power highlighted by the Public Staff and the Utilities. Witness Vitolo instead focuses solely on lowering the costs of or otherwise easing the development process for solar QFs. The current economic and regulatory circumstances guide the Commission's decision, however, and they simply do not support maintaining the status quo. The Commission is likewise not persuaded that reducing the threshold to 1 MW will result in QFs foregoing economies of scale to build smaller projects to avoid negotiation. As Cypress Creek Witness McConnell testified, even with the 5 MW threshold, certain QF developers are already seeking out greater economies of scale by building larger facilities subject to negotiated contracts. Instead, the Commission agrees with Witness Bowman that eliminating the incentive to arbitrarily develop 5 MW thresholds may improve economies of scale if QF developers transition to developing larger projects.

Finally, the Commission also does not agree that lowering the threshold will result in protracted and costly negotiations with the Utilities. Although the Commission expressed concern about the negotiation process in the *Sub 140 Phase I Order*, the Utilities have presented testimony and evidence showing that they have gained experience in "standardizing" the large QF negotiations, and that, in many cases, they are negotiating with parties that are very familiar with both the process and the typical PPA terms and conditions. The Commission notes that the number of negotiated PPAs has increased since 2014 and that such PPAs are filed with the Commission for information. Although SACE Witness Vitolo submitted evidence that tended to show that negotiations for a PPA could take some time, his evidence did not fairly reflect that QFs have up to six months to execute a PPA after a utility submits it for signature. This six month time period, when the PPA is in the control of the QF, could add to the appearance that negotiations are protracted.

With respect to the scope of the negotiations between QFs greater than 1 MW and DEC/DEP, the Commission notes that the Companies have emphasized that their PPA negotiations must follow FERC and Commission guidance. FERC regulations specifically provide that the following factors should, to the extent practicable, be considered and taken into account in setting avoided cost rates: (i) the ability of the utility to dispatch the QF; (ii) the expected or demonstrated reliability of the QF; (iii) the terms of any contract or other LEO, including the duration of the obligation; (iv) the extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utilities' facilities; (v) the usefulness of the energy and capacity supplied from the QF in emergencies; and (vi) the individual and aggregate value of energy and capacity from QFs on the electric utility's system. 18 C.F.R. § 292.304(e). Further, the Commission notes that the FERC recently recognized that its regulations provide that a state regulatory authority may establish lower avoided cost rates for purchases from intermittent QFs than for purchases from firm QFs, recognizing similar factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QF's energy and capacity in its decision in *Windham Solar, LLC*, 157 FERC ¶ 61,134 at 6 (2016) ("*Windham Solar*"). In addition, the Commission has directed the Utilities to negotiate with QFs in good faith and has listed specific issues (similar to the FERC's factors listed above) to be addressed in negotiations with large QFs and QFs not otherwise eligible for the standard offer. These issues include:

- The appropriate contract and the parties' best forecast of avoided capacity and energy credits over the duration;
- Capacity credits that reflect the need (or lack of need) for additional capacity at the time deliveries under the contract are actually to be made;
- The availability of capacity during the utility's daily and seasonal peaks;

- The utility's ability to dispatch the QF;
- The expected or demonstrated reliability of the QF;
- The terms and provisions of any applicable contract or other LEO, including the termination notice requirement and sanctions for noncompliance;
- The extent of which the scheduled outages of the QF during system emergencies, including its ability to separate its load from its generation;
- The individual and aggregate value of the capacity from the QFs on the utility's system;
- The smaller capacity increments and shorter lead times that might be available with the additions of capacity from QFs;
- The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from the QF;
- The alternative of long-term rates that are not levelized or only partially levelized;
- The alternative of long-term rates that include levelized capacity payments and variable energy payments;
- Appropriate notice prior to the expiration of the contract term, the renewability of the contract, and the provisions for setting the appropriate rates for each renewed contract; and
- The appropriate security bond or other protection for the utility if levelized or partially levelized payments are negotiated.

See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 12-13, Docket No. E-100, Sub 66 (July 16, 1993).

In addition to this long-established guidance, the Commission's 'Sub 140 Phase I *Order on Clarification* also more recently addressed the allowable parameters for negotiating with large QFs. *Order of Clarification*, Docket No. E-100, Sub 140 (Mar. 6, 2015) ("*Clarification Order*"). In the *Clarification Order*, the Commission directed that in the course of bilateral negotiations, the Companies are expected to use the most up-to-date data to determine inputs for negotiated rates and that any party "is free to identify specific characteristics of a particular QF that merit consideration in the calculation of negotiated avoided cost rates." *Id*. at 3. By accounting for the factors listed in the FERC's regulations and prior Commission orders, DEC/DEP Witness Snider has indicated that avoided cost rates can be more precisely tailored for QFs greater than 1 MW to recognize the value that the individual QFs are providing to our customers, which will result in more accurate avoided costs and well-planned and coordinated integration of PURPA solar into the Companies' systems. Furthermore, the QFs may always request or review the inputs to the calculated avoided cost rates, and if the QF disagrees with the calculations, it may file a complaint or petition the Commission to review the Utilities' proposed avoided cost calculations through arbitration. *Id.*

The Commission remains concerned, however, that arbitrations and complaints may begin to arise if reasonable transparency of the Utilities' avoided cost rate calculation is not ensured. If this proves to be the case, the Commission will establish a new proceeding to evaluate how the Utilities determine their avoided costs for large QFs. At this time, however, the Commission determines that such a proceeding is not necessary and prefers to allow the Utilities and QFs to use the contracting procedures process approved later in this order and to work amicably and in good faith towards negotiating avoided cost rates and terms and conditions consistent with guidance discussed above.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this Finding of Fact is found in DEC/DEP's Joint Initial Statement, the direct and rebuttal testimony of DEC/DEP Witnesses Bowman and Snider, DNCP Witnesses Gaskill and Petrie, the testimony of Public Staff Witness Hinton, Cypress Creek Witness McDonnell, SACE Witness Vitolo, and NCSEA Witnesses Strunk, Harkrader, and Johnson.

In her direct testimony, Witness Bowman testified in support of DEC/DEP's proposed Schedule PP and Schedule PP-3, respectively, and rate design presented in the Joint Initial Statement, explaining that DEC/DEP proposed eliminating the 5-year and 15-year standard contract term options and instead offering a single 10-year contract with fixed avoided capacity rates and avoided energy rates that update every 2 years as part of the Commission's biennial review of the Utilities' avoided costs.[6] Under DEC/DEP's proposal, the capacity component of DEC's and DEP's avoided cost rates would recognize the capacity value of the QF starting in the first year that DEC's or DEP's IRP demonstrates an actual capacity need. Witness Bowman further explained that DEC/DEP's proposed rate design moderates the utilities' near term lack of capacity need by levelizing the capacity component over the 10-year term of the proposed standard contract. The avoided energy rates will be reset at every future biennial proceeding,

[6] The Avoided Energy Rates referred to in Witness Bowman's testimony are reflected in Schedule PP and Schedule PP-3 as Energy Rate Credits applicable under Fixed, Long-Term (10-year) option.

which will mitigate the risk of over- or under- projecting long-term commodity prices. This two-year adjustment serves two purposes: first, it protects customers from overpaying for avoided energy in future years when fuel commodity prices are not as certain, and second, it provides QFs a continuing stream of revenue, with a potential upside benefit of increased rates if energy prices increase above forecasted levels. (Tr. Vol. 2 at 349-350).

Witness Bowman acknowledged that the Commission had previously declined to eliminate the 15-year long-term fixed contracts, but argued that, at this time, economic and regulatory circumstances compelled the Commission to restrike the balance between encouraging QF development on the one hand and protecting customers from the risk of overpayment on the other. Witness Bowman noted that long-term avoided cost rates in excess of DEC's and DEP's actual avoided costs, long-term fixed rate contracts, and the low threshold to establish a LEO have resulted in large numbers of solar QFs locking in avoided costs rates that are well in excess of the DEC/DEP's actual avoided costs in North Carolina for the next 15 years. She explained that as the number of solar QFs requesting to sell power under the standard avoided cost rates increases, the financial burden and risk of overpayments from these long-term fixed contracts likewise increase for DEC's and DEP's customers. Witness Bowman testified that DEC/DEP's proposal aims to align the avoided energy cost paid to QFs with the DEC/DEP's Companies' actual system incremental avoided costs. (Tr. Vol. 2 at 350-53).

Witness Bowman next testified that DEC/DEP's proposal to adjust avoided energy rates every two years was consistent with PURPA, which requires avoided cost rates that are just and reasonable to customers, in the public interest, and not discriminatory to QFs. This means that avoided cost rates should not exceed the incremental costs of alternative energy that the utility would generate or purchase from another source. Witness Bowman stated that if contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate. She further noted that PURPA does not prescribe a minimum or maximum term for a "long-term" contract, and that different states offer differing terms. She contrasted South Carolina, which has a maximum 10-year fixed long-term contract, with Georgia, which has a maximum 5-year fixed long-term contract.[7] Witness Bowman further noted that Tennessee, Alabama, and Mississippi have all approved minimum standard offer terms of one year. Moreover, she noted that the Idaho Public Utilities Commission recently approved a two-year fixed contract term for wind and solar QFs larger than 100 kW. (Tr. Vol. 2 at 353-54).

DEC/DEP Witness Snider also supported the proposed 10-year maximum term standard contract with capacity rates fixed over the term and energy rates readjusted as part of the Commission's biennial avoided cost proceedings. He first explained that approximately 1,600 MW of utility-scale QF solar generators are now interconnected and delivering power to DEC/DEP under prior Commission-approved avoided cost rates, and an additional 1,100 MW of proposed solar QFs either in development or under construction have also taken the steps required to "lock in" to the Sub 136 and Sub 140 standard avoided cost rates that the Commission previously approved. Witness Snider explained that these growing risks associated with the long-term financial obligations under existing PURPA standard offer contracts has driven DEC/DEP's proposed

[7] The Commission notes that the Georgia Power Company's Solar Purchase Schedule SP-2 was discontinued for new customers in July 2016. Public Staff Witness Hinton testified during the hearing that authorized fixed-term standard offer available in Georgia Power's service territory to QFs 100 kW or less is now two years. (Tr. Vol. 3 at 95; Tr. Vol. 8 at 143).

modifications to its Schedules PP and PP-3 rate design in this proceeding. Development of these additional solar QFs inevitably means that DEC/DEP's financial obligation under PURPA and customers' exposure to overpayments could increase significantly in the future. (Tr. Vol. 2 at 200-01).

Witness Snider then specifically testified that entering into long-term fixed price contracts without regard to changing commodity market conditions had caused the citizens and businesses of North Carolina to pay for QF generation at this substantially higher cost. Overpayment in energy rates to the QFs is driven primarily by the significant decline in fuel commodity prices over the last several years. Witness Snider explained that in general, 10-year levelized gas prices had fallen approximately 40% and coal prices had fallen approximately 16% for that same period as compared to those used in calculating DEC/DEP's avoided energy cost in the 2014 Sub 140 proceeding. He asserted that if energy rates were recalculated more regularly, they would better align with future fuel commodity prices. Therefore, to mitigate the potential harm to DEC/DEP's customers of long-term overpayments in excess of actual future avoided costs, the Companies have modified their proposed standard offers to balance the QF's interests for fixed longer-term contracts while limiting the significant fuel commodity forecast price risk for DEC/DEP's customers going forward. Witness Snider testified that adjusting energy rates at reasonable, periodic intervals throughout the duration of a long-term contract is an effective way to reduce customers' exposure to overpayments. (Tr. Vol. 2 at 204-05).

Witness Snider also contrasted the PPAs that DEC and DEP enter into outside of PURPA with those under PURPA. DEC/DEP's PPAs outside of PURPA generally do not include long-term commodity price risks. DEC and DEP also seek to procure energy or build new generation based on a need that is typically defined in DEC's or DEP's IRPs. When DEC or DEP solicit offers for new energy or capacity, the Commission reviews the prudence of the proposed resource options by assessing the economics and the risks with the objective of procuring the least cost, least risk assets for customers. Further, when a PPA is negotiated outside of PURPA, the energy payment terms are generally linked to a real time fuel price index, and, as such, DEC and DEP minimize the risk of the customer paying beyond market energy prices. Witness Snider concluded that the Companies' proposed modification to the standard offer structure better aligns the level of risk imposed upon customers in PURPA contracts with those in non-PURPA ones. (Tr. Vol. 2 at 206).

DNCP Witnesses Gaskill and Petrie also testified in support of reducing the standard offer's maximum 15-year term. Like DEC and DEP, DNCP sought to mitigate its customers' exposure to the significant above-market payments for QF output resulting from a 15-year PPA. Witness Gaskill proposed that QFs that qualify for the standard contract may enter into a PPA with a 5-year or 10-year term. DNCP's proposal differed from DEC/DEP's by fixing both the energy and capacity payments over the 10-year term of the PPA. Witness Gaskill agreed, however, that the fixed long-term prices provided in PPAs are based on projections of future costs for electricity. He noted that combustion turbines, construction, and operating costs have decreased as performance has improved and fuel costs have fallen. As a result of this mismatch, DNCP's customers pay more than DNCP's true avoided cost for QF output. Witness Gaskill further demonstrated that DNCP's avoided costs have dropped approximately 10% per year since the Sub 136

(2012) proceeding. Witness Gaskill concluded by noting that a 10-year term was consistent with PURPA, citing the 6 non-standard 10-year contracts that DNCP had entered into with solar QFs ranging from 12 MW to 20 MW. (Tr. Vol. 5 at 159-63).

The Public Staff generally supported DEC/DEP's and DCNP's proposal to reduce the maximum term of the standard contract to 10 years, but did not support DEC/DEP's readjustment of the energy rates every two years. Due to the rapid pace of QF development in North Carolina, Witness Hinton accepted the Utilities' proposal to limit the standard term offer to 10 years as reasonable because it would serve to reduce the significant overpayment risk borne by customers over a longer term. He noted that DEC and DEP have signed 22 PPAs with QFs at 10-year terms, and that 6 of DNCP's 12 non-standard PPAs have 10-year terms, indicating that securing financing terms shorter than 15 years was possible. Witness Hinton further recommended that the Commission continue to monitor the amount of actual QF development and the stability of the avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to seek financing on reasonable terms. (Tr. Vol. 8 at 65-73).

Witness Hinton opposed, however, DEC's and DEP's proposal to reset energy rates every two years. Generally relying on the FERC's recent November 2016 decision in *Windham Solar*, Witness Hinton testified that he did not believe that the standard offer contract with a two-year reset on the avoided energy rates would provide "sufficient certainty with regard to return on investment." (Tr. Vol. 8 at 75). Witness Hinton suggested instead other methods of calculating energy rates to reduce customers' risk of overpayment, such as linking available energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment on energy rates varying from some indicative pricing. Witness Hinton believed that these options may reduce ratepayers' risk of overpayment while still providing QFs with additional certainty. (Tr. Vol. 8 at 75-77).

Other intervenors disagreed with the Utilities' proposals to eliminate the 15-year maximum long-term standard PPA and with DEC/DEP's proposal to adjust the avoided energy rates over the duration of the contract every 2 years as part of the biennial avoided cost case. The intervenors primarily argued that the proposed 10-year maximum term PPA was not sufficiently long for financing and that DEC/DEP's proposed 2-year energy rate adjustment jeopardized solar QFs ability to obtain project financing because the rates were not fixed over the length of the PPA.

Cypress Creek Witness McConnell testified that the term of the PPA is significant for purposes of raising capital for constructing and operating QFs. He noted that without reasonable certainty as to contracted cash flows based on a defined term at a defined price, the institutional marketplace is generally unwilling to take a price risk. According to Witness McConnell, many in the industry considered the 15-year PPA length actually insufficient for financing compared to average utility tenors of 20 or 25 years. He contended that 10-year PPAs will lead to 10-year amortization periods, which will mean less debt and greater sponsor equity requirements at lower returns and greater risk. (Tr. Vol. 6 at 114-17).

NCSEA Witness Johnson and SACE Witness Vitolo generally echoed these arguments. As an initial matter, Witness Johnson doubted the $1 billion overpayment calculation by Witness Snider because, in Witness Johnson's opinion, it exaggerated the impact of the recent decline in fuel prices, and he disputed that existing QF contracts will be costlier than power produced by generating units that DEC and DEP own and operate over the duration of the QF contracts. Therefore, Witness Johnson did not see a need to allow energy rates to be re-established every two years. Witness Johnson also noted that the proposal will result in a highly predictable revenue stream becoming highly unpredictable for QFs and their financiers because it will be depend on the outcome of "litigated proceedings every two years." (Tr. Vol. 6 at 268-69).

With respect to the 2-year energy rate adjustment within the 10-year term, NCSEA Witnesses Strunk testified that there is no "bright line" differentiating a financeable project from a non-financeable one. He contended that getting a new power project financed "with reasonable quantities of debt" tends to hinge on factors such as the amount of equity committed, the interest paid, payback periods, and other terms, as well as the lenders' risk in extending credit to the project. He indicated that reducing the PPA term and including a 2-year energy rate reset raises the $/kWh price that a QF requires to be viable for two reasons: 1) the QF's cost of capital will increase as its investors bear more risk; and 2) investors will seek shorter amortization periods for capital investments, which in turn translate to higher short-term cash flow requirements. Witness Strunk also noted that lenders typically rely upon fixed pricing for assurance that the project will be in a position to service its debt. With respect to the proposed 2-year energy rate adjustment, Witness Strunk testified that lenders would view the coverage period as only 2 years because they would discount the revenues after that first 2 years. He concluded that "if energy pricing were fixed for the entire period of the PPA term, that level of discounting would not occur and higher debt levels could be used to finance the project."

(Tr. Vol. 6 at 19-22).

Witness Strunk indicated that, in theory, a developer could solve some of these problems by contributing more equity or even the entirety of funds needed to construct the facility, but he noted that would be unrealistic. Equity investors in such projects are often capital constrained and seek to employ debt leverage as part of attractive financial structures. He further noted that an equity investor would require higher returns, all things equal, with 2-year PPA energy price resets as compared to energy prices fixed for the term of the PPA. In sum, Witness Strunk concluded, the proposed 2-year reset drives up the cost of financing. (Tr. Vol. 6 at 22-23).

SACE Witness Vitolo also indicated that reduced payments to QFs necessitate lower monthly debt payments for the project to have a positive monthly cash flow. Reducing the fixed contract duration from 15 to 10 years would result in higher, not lower, monthly debt payments for QFs. Witness Vitolo believed that the Utilities' proposals were inconsistent with the Commission's *Sub 140 Phase I Order*, as well as the FERC's *J.D. Wind* Orders and the recent *Windham Solar* decision. Witness Vitolo also expressed concerns that solar QF projects would be treated differently than utility projects with respect to contract duration, as the Utilities depreciate and recover their utility-owned PV assets over longer recover periods as part of cost-of-service. Witness Vitolo recommended that the Commission maintain its current policy of requiring the Utilities to offer 15-year maximum contracts or, in the alternative, require the Utilities to offer PPAs that match the respective recovery period of the Utilities' own PV assets. (Tr. Vol. 7 at 31-35).

In rebuttal testimony, Witness Bowman provided additional justification for

DEC/DEP's proposed 10-year contract term with the 2-year avoided energy adjustment in response to the concerns raised by the Public Staff and other intervenors. She testified that DEC/DEP appreciate the Public Staff's and other parties' concerns that small QFs and their potential investors require certainty in terms of the avoided cost rates to be offered to determine whether to develop a project. She noted that the FERC's PURPA regulations have long provided a method through the forecast information required to be filed with the Commission pursuant to 18 C.F.R. § 292.302 for QF investors to evaluate the utility's longer-term need for capacity and the forecasted cost of energy. As explained in *Order No. 69*, this data can be used by QFs and their investors in evaluating the utility's future avoided costs. (Tr. Vol. 2 at 400-02). Although Witness Bowman testified that she was not an expert in contract terms and conditions that the financial community would deem reasonable to allow QFs to attract capital, she understood that numerous considerations, including a QF developer's balance sheet, management team experience and creditworthiness, as well as avoided cost-specific considerations including price, contract tenor, the cost of capital, all come into play in determining whether an investment can attract debt and/or equity capital. PURPA largely exempts QFs from state regulatory authority over their rates and business operations so that neither DEC/DEP, the Public Staff, nor the Commission has any clear insights into a QF developer's business or the level of profit deemed reasonable to attract equity capital. (Tr. Vol. 2 at 402-03).

Witness Bowman also disputed testimony from intervenors that the FERC's recent *Windham Solar* decision prohibited DEC/DEP's proposed 2-year updates of avoided energy rates in an otherwise fixed 10-year PPA. She agreed that the FERC found in *Windham Solar* that PURPA's directive to encourage QFs suggests that a LEO should be sufficiently long to allow QFs reasonable opportunities to attract capital from potential investors. Witness Bowman pointed out, however, that *Windham Solar* arose in the context of rates offered by a Connecticut utility in the ISO-New England organized market and, further, that the FERC did not specify a particular number of years for such LEOs, leaving the proper term to the discretion of the State Commissions. She noted that Alabama was the only jurisdiction outside of an organized wholesale market to consider the FERC's recent *Windham Solar* decision in setting forecasted avoided cost rates under PURPA. In early March 2017, the Alabama Public Service Commission (Alabama PSC) approved Alabama Power Company's (Alabama Power) standard rate offer for QFs with a design capacity above 100 kW, which offers Alabama Power's forecasted energy and capacity rate over a one-year term with an "evergreen provision" under which avoided cost pricing updates annually consistent with the updated avoided energy pricing submitted by Alabama Power.[8] The Alabama PSC held the rate structure was consistent with PURPA and with prior FERC guidance that a long-term contract is one year or longer under PURPA.[9] (Tr. Vol. 2 at 403-06; Tr. Vol. 5 at 45-49; Duke Bowman Redirect Exhibit No. 1). Ms. Bowman was unaware of any state in the Southeast with a contract term of more than 10 years under PURPA. (Tr. Vol. 5 at 48). For these reasons, Witness Bowman testified that the FERC's recent *Windham Solar* decision should not materially change the Commission's analysis of DEC/DEP's proposed standard offer structure.

Witness Bowman also rebutted Witness Vitolo's assertion that the Commission

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[8] *Alabama Power Company, Petition for Approval of Rate CPE – Contract for Purchased Energy*, Docket No. U-5213 (March 7, 2017) ("Duke Bowman Redirect Exhibit No. 1").
[9] *Id.*

had previously denied a similar biennial reset of the avoided energy rate for DNCP in the 2010 Sub 127 avoided cost proceeding on the ground it was inconsistent with the FERC's *J.D. Wind* Orders.[10] Witness Bowman asserted that DEC/DEP's proposal in this proceeding was in response to the current economic and regulatory circumstances. She also noted that DNCP had used the biennial reset method from 1989 to 2010 prior to the Commission directing it to transition to fixed, levelized avoided energy rates. Additionally, Witness Bowman disagreed that PURPA or the FERC's regulations prohibited such a biennial reset, and noted that the Commission had allowed DNCP to offer its 2-year fixed energy rate during 2010-2011. Finally, she testified that prohibiting this option perpetuates North Carolina's status as an outlier that significantly encourages QF development compared to other southeastern states, such as Alabama, Arkansas, Florida, Kentucky, Louisiana, Maryland, and Virginia. Witness Bowman cited NCSEA Witness Johnson's testimony that these states offer shorter-term variable rates, rather than fixed, long-term rates. (Tr. Vol. 2 at 409-411).

Witness Bowman also rebutted SACE Witness Vitolo's claim that QF fixed contracts should match the recovery period of the DEC/DEP's own PV and other generating assets. She distinguished QF contracts from utility-owned ones in multiple ways. First, utility resource additions are driven by need, which the Utilities establish through an extensive IRP and CPCN application process. In contrast, the PURPA must-purchase requirement mandates QFs be reimbursed for selling power to DEC and DEP whether or not the power is needed. Next, Witness Bowman noted that utility load-following generator resources are dispatchable. She also explained that because the Utilities were not locked into long-term fixed contracts, they can pass lower fuel and

[10] *J.D. Wind W, LLC*, 130 FERC ¶ 61, 127 (2010), *reh'g, denied* 129 FERC ¶ 61,148 (2009) ("*J.D. Wind*").

other operating cost savings to customers. A utility, however, cannot dispatch or back down a QF when more economic alternatives are available, so customers ultimately pay for potentially higher-cost QF energy produced by a QF. Long-term contracts exacerbate this inefficiency. She testified that QFs do not actually advocate for a longer cost recovery period based upon actually recovering their cost of service, but only to extend the period of guaranteed revenue (and profit) out into the future. (Tr. Vol. 2 at 411-12).

DNCP Witness Gaskill also responded to Witness Vitolo's concern that QF solar projects are treated differently than utility projects because utility-sponsored projects depreciate capital over their lives. Witness Gaskill noted several differences between rate regulated utilities and QFs with respect to how they are organized, regulated, financed, and how they obtain cost recovery. Utilities operate under cost-of-service rate recovery, which differs significantly from how independent power producers, like QFs, recover their costs. If a utility builds a solar facility and places it into rate base, all of the benefits, including fuel savings, revenue from renewable energy credits (RECs), and investment tax credits are passed on to customers. Witness Gaskill contrasted this with QFs, which are paid the marginal costs for both capacity and energy and retain all other revenue streams from RECs and tax credits. (Tr. Vol. 5 at 183-84).

In his rebuttal testimony, Witness Snider agreed that Public Staff Witness Hinton's suggestion to link available energy rates to a publicly available composite fuel index was a reasonable alternative to the 2-year reset of energy payments. (Tr. Vol. 2 at 243). To Witness Snider, this accomplished minimizing the risk of overpaying QFs for the energy that they provide. Witness Snider agreed to further evaluate incorporating this proposal in its rate design in the next biennial proceeding. As an interim measure, however, and in response to specific concerns raised by the intervenors that the 2-year update to energy rates was too risky and unpredictable for QFs 1 MW and less to obtain financing, Witnesses Bowman and Snider offered a "compromise proposal" in their rebuttal testimony. The compromise proposal would allow QF developers the option to "fix" the underlying 2-year avoided energy rate filed with the Schedules PP for the duration of the 10-year contract. Witness Snider noted that the 2-year fixed Schedule PP annualized energy rates were only slightly below the fixed 10-year Schedule PP-H annualized energy rates. He viewed this as an acceptable albeit imperfect allocation of longer tem risk forecast between QFs and DEC's and DEP's customers at this time. (Tr. Vol. 2 at 243-44). Additionally, he testified that DEC/DEP viewed this compromise offer as an interim rate design to be considered with the Public Staff's other alternative options, such as linking avoided energy rates to a fuel index, in the next biennial proceeding. (Tr. Vol. 2 at 408-09, 243-44).

On cross-examination, Witness Hinton testified that he had reviewed other state's implementation of PURPA, particularly with respect to the length of PPAs. (Tr. Vol. 8 at 143). He agreed that in Georgia, standard offer QF rates have energy rates fixed for only two years, and he agreed that this was a fixed rate. (Tr. Vol. 8 at 144-48, 153). He opined that Georgia's model of implementing PURPA was inconsistent with "how North Carolina has historically implemented PURPA." (Tr. Vol. 8 at 153). Although not an attorney, Witness Hinton expressed his concern that Georgia's method of implementing PURPA was discriminatory. He compared a utility to a QF with respect to building generation, arguing that a utility would not build a generating unit knowing it would only get recovery over a 2-year time period. In sum, he argued that in Georgia, there is too much risk placed on the QF relative to the risk the Utilities have. However, he acknowledged that the ratepayers ultimately bear the risk if the QF does not. (Tr. Vol. 8 at 153-55). Although Witness Hinton opposed DEC/DEP's "compromise proposal" to fix the currently proposed 2-year energy rate for the duration of the 10-year contract, he conceded on cross-examination that allowing the QF this option would mitigate the significant forecast risks of over- or under-projecting long-term commodity costs and provide certainty over the 10-year period. (Tr. Vol. 8 at 150-51).

Discussions and Conclusion

Based on the current economic and regulatory circumstances, the Commission concludes that it should require DEC and DEP to make available a standard offer rate option with a maximum term of 10 years. With respect to DEC/DEP, they are required to offer, at the QF's election, a standard contract with a maximum 10-year term with fixed capacity rates and energy rates that adjust every two years as part of the Commission's biennial avoided costs review or a standard contract with a maximum 10-year term with fixed capacity rates and energy rates that are fixed over the 10-year at the 2-year energy rate that DEC/DEP filed in this docket.

10-year Maximum Term Standard Offer

The Commission has the authority and discretion under both PUPRA and state law to direct the Utilities to offer long-term fixed standard offers with 10-year terms.[11] Under FERC's regulations, a QF has the option to commit to sell energy or capacity pursuant to a LEO for future delivery over a specified term. 18 C.F.R. § 292.304(d)(2). Furthermore, as the Commission has recognized in recent orders, the FERC has ruled that

[11] *See, e.g., Windham Solar* at 8, fn. 13 (explaining that FERC regulations do not specify a particular number of years for LEOs, meaning that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing State Commissions).

QFs have a right to fixed long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred. The FERC, however, has never specified a minimum or maximum term, leaving this determination to the States. The North Carolina General Statutes similarly do not specify a term for such contracts. For example, N.C. Gen. Stat. § 62-133.8(d) provides that the "terms of any contract entered into between an electric power supplier and a new solar electric facility or new metered solar thermal energy facility shall be of sufficient length to stimulate development of solar energy." The statute does not provide a definition of "sufficient" length, however. Moreover, the statute expressly pertains to "Compliance with REPS Requirement Through Use of Solar Energy Resources;" therefore, it is directly applicable to bundled REC contracts or Renewable Power Purchase Agreements between renewable energy facilities and the Utilities. This statute does not appear to directly apply to PPAs between the Utilities and QFs under PURPA that do not involve the transfer of RECs.

Additionally, the Commission has consistently stated that the issue of the maximum length of the standard offer for QFs is one the Commission "must continuously reconsider as economic circumstances change from one biennial proceeding to the next." *See, e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 7, Docket No. E-100, Sub 87 (April 6, 2000). The Commission has reviewed the issue of whether it should require the electric utilities to offer long-term levelized rates to QFs as standard rate options of 5, 10, and 15 years in prior avoided cost proceedings, including Docket No. E-100, Subs 79, 81, 87, 96, 100, and most recently, Sub 140. In reviewing this issue, the Commission has always aimed to strike a balance between encouraging QF development on the one hand, and reducing the utilities' (and thereby, customers') exposure to overpayments and stranded costs on the other. *Id.*

The evidence in this docket overwhelmingly shows that the tremendous growth of 5 MW solar QFs in the Utilities' service territories has resulted in the QFs entitled to long-term contracts no longer being of "limited number and size" as the Commission has found in past proceedings. The Commission agrees with Public Staff Witness Hinton that the sheer volume of QF projects, along with the continued rapid pace of QF development in North Carolina and significant overpayment risk for customers supports the Commission decision in this proceeding to approve a shorter-term structure for avoided cost rates. (Tr. Vol. 8 at 23, 69-72). The Commission recognizes that as the number of solar QFs requesting to sell power under standard avoided cost rates increases, the financial burden and "overpayment" risk for utility ratepayers increases. Due to the recent surge in solar QF development in North Carolina, the balance has shifted heavily toward encouragement of QFs, and this overpayment risk is no longer compatible with PURPA's central mandate that avoided cost rates and policies must be just and reasonable to utility customers and in the public interest.

Moreover, the Commission is unpersuaded by recommendations that it should retain the status quo 15-year maximum contract term because overestimations and underestimations of avoided cost will "balance out" in the long run due to QF development remaining essentially constant regardless of avoided cost and regulatory circumstances. The surge of solar QF development projects in recent years that have contracted at long-term fixed rates disproves this assumption. The Commission finds that the offer of long-term fixed rate contracts, with terms longer than most surrounding states, have been one compelling factor in attracting this tremendous influx of solar facilities to develop in North Carolina. The ability for QFs to "lock-in" to a 15-year maximum contract term has attracted increasingly more QFs to North Carolina, which has resulted in corresponding significant overpayment commitments by customers. These significant overpayment amounts far exceed the potential for counterbalancing underpayments for the foreseeable future. Accordingly, the Commission finds that the Utilities' proposal for a 10-year maximum standard offer PPA more appropriately balances PURPA's mandates of encouraging QF development and protecting customers from the risk of overpayments.

The Commission also does not agree that a 10-year maximum PPA is discriminatory in violation of PURPA because it results in QF solar projects being treated differently than utility projects with respect to recovery of costs. Put simply, rate regulated utilities and QFs differ in terms of how they are organized, regulated, and financed, as well as how they obtain cost recovery. The Commission agrees with the testimony of DNCP Witness Gaskill and DEC/DEP Witnesses Snider and Bowman that a utility must operate under cost-of-service rate recovery, which differs from how QFs recover their costs. (Tr. Vol. 5 at 183-84). The Commission notes that, for example, when a utility builds a plant and places it in rate base, it does not receive forecasted avoided cost for energy and capacity like the QFs, but instead only earns a return on capital invested to meet its obligation to serve. Further, the addition of new utility-owned generation is driven by integrated resource planning that is highly scrutinized by the Public Staff, other interested parties, and Commission in CPCN proceedings, where the utility must usually demonstrate that the investment can be used to cost-effectively service customer energy and capacity needs. In contrast, a QF has no limit on, and the

Commission has no right to review, the amount of debt QFs may use for financing, the return on equity, or the overall rate of return. Significantly, as pointed out by DNCP Witness Gaskill, the longer depreciation lives for utility-owned assets are intended to lower the near-term rate impact for utility projects because lower annual depreciation costs are passed directly to the customers through a lower revenue requirement. In contrast, any such savings from longer PPAs and lower financing costs are retained as profit by the QF developer and its investors and are not flowed through to customers. Because of these significant differences between QFs and utility cost recovery, the Commission therefore does not find that QFs must be allowed to have PPAs with maximum lengths that match the recovery period of the respective utility's own assets. Matching these recovery periods would dramatically shift the balance too far towards benefitting QFs while exposing customers to even more overpayment risk.

The record in this proceeding also does not support the position that reducing the standard offer term from the 15 years to 10 years will result in QFs being unable to finance projects. The Commission will discuss the issue of financing projects in more detail below, but with respect to the issue of a 10-year term, evidence in the record shows that DEC and DEP were already offering larger QFs negotiated PPAs with terms of 10 years. Moreover, as Witness Bowman testified, no Southeastern state has a PPA term of longer than 10 years under PURPA. Witness Hinton also testified that the Public Staff's investigation supported a 10-year term as reasonable to allow QFs to attract financing in light of current conditions. (Tr. Vol. 8 at 73, 231). Based on foregoing, the Commission finds and concludes that it is just, reasonable, and consistent with PURPA for DEC and DEP to offer QFs 1 MW and less a 10-year maximum term contract as they have proposed, subject to the considerations discussed below.

<u>QF Election of 2-Year Adjustment to Energy Rates and DEC/DEP's Compromise Proposal</u>

As discussed above, the Commission agrees that reducing the standard offer term to 10 years will mitigate some risk of future overpayment by DEC's and DEP's customers. Because of the compelling economic and regulatory circumstances discussed previously in this Order, however, the Commission determines that it is also necessary to further mitigate the risk of overpayments that results from forecasted commodity prices potentially in excess of the Companies' future incremental cost of alternative energy. The shifting of this growing commodity price forecast risk to customers becomes increasingly unjust, unreasonable, and contrary to the public interest as greater QF capacity avails itself of these longer-term rates. Therefore, for the reasons discussed in more detail below, the Commission finds that DEC/DEP's proposal to fix the avoided capacity rates over the 10-year length of the contract and to offer QFs the election of either: adjusting the energy rates every two years as part of the Commission's biennial avoided cost proceeding or fixing the energy rates at energy rates filed in this docket is a just and reasonable interim solution to mitigate the risk of customer overpayments for PURPA power.

As noted previously, the term and structure of forecasted avoided cost rates is left to the discretion of the State Commission implementing PURPA. PURPA requires that avoided cost rates are just and reasonable, in the public interest, not discriminatory to QFs, and that avoided cost rates do not exceed the cost of the energy that the utility would have incurred through self-generation or otherwise, but for the purchase of from the QF. 16 U.S.C. § 824a-3(b); (d). DEC/DEP Witnesses Snider and Bowman have provided persuasive evidence showing that when standard offer contracts extend for many years, the forecasted rates become increasingly inaccurate, no longer mirroring the utility's incremental costs of alternative energy at the time of delivery. Witness Snider testified that since the Sub 140 avoided cost proceedings, 10-year natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period. Compared to 2012, fuel costs have fallen even further with natural gas declining approximately 48%, and coal, 33%. (Tr. Vol. 2 at 203). At the same time, solar QF development in North Carolina has been unprecedented, growing tremendously over the past two years, as evidenced by the continued pace of new CPCN applications filed with the Commission. Significant numbers of solar QFs with LEOs established since 2012, but before 2016, have locked into standard offer contracts with avoided energy rates that do not account for those changes in commodity market conditions. Therefore, those reductions in commodity prices will not be passed along to the Utilities' customers through these contracts. As Witness Snider highlighted, the combination of surging solar development and the recent deviation in market-based commodity costs compared to prior forecasts have resulted in customers being obligated to significant long-term overpayments when compared to DEC/DEP's current forecast of avoided costs. Continuing the existing policy would exacerbate customers' already significant overpayment obligations in the future. Thus, the Commission finds that an avoided energy payment that resets every two years after review by the Commission is a just and reasonable interim solution to mitigating that risk.

Central to the intervenors' arguments against the avoided energy rates being reset every two years, however, is that this reset would render the contracts not "financeable" because the resulting revenue streams would not allow QFs a reasonable opportunity to attract capital from investors and would be unpredictable. The Commission notes that FERC has provided little guidance on whether and how State Commissions tasked with implementing PURPA are to determine whether a standard offer PPA is "financeable" or how to balance the Commissions' discretion to establish just and reasonable terms and conditions to implement PURPA that align with other numerous other jurisdictions against intervenors' allegations that the proposed PPA terms are "not financeable." The evidence in this hearing showed that, unlike when a utility obtains a CPCN to develop generation, numerous factors beyond the Commission's jurisdiction can impact whether a QF developer is able to finance a project. (Tr. Vol. 5 at 75-76). Those factors include the developer's capital costs, operations and maintenance costs, land costs, creditworthiness, and how much equity a developer might invest in the facility. (Tr. Vol. 5 at 76-78; Tr. Vol. 2 at 402-03). In short, the Commission agrees with Witness Strunk that there is no bright line test to determine whether every QF developer will be able to finance every proposed project under the standard offer. The Commission, therefore, must look to whether the evidence in this proceeding supports DEC/DEP's standard offer proposal as consistent with PURPA. Put another way, the Commission must determine, as it has many times before, whether the Companies' proposed standard offer term strikes a balance between encouraging QF development on the one hand, and protecting customers from the risk of overpayment on the other.

Contrary to the arguments of the intervenors, the Commission does not find that the FERC's recent dicta in *Windham Solar* materially alters this long-established scope of review. In *Windham Solar*, the FERC found, among other things, that given the QF's need to enter into contractual commitments based upon estimates of future avoided costs and the need for certainty with regard to return on investment, PURPA's directive to encourage QFs suggests that a LEO should be long enough to allow QFs reasonable opportunities to attract capital from potential investors. The Commission notes, however, that *Windham Solar* arose out of Connecticut's implementation of PURPA within the organized ISO-New England wholesale power market. In that market, the state's purchasing utilities offered only a real-time energy avoided cost rate and did not recognize that QFs could meet future capacity needs. In contrast, the Companies' Schedules PP and PP-3 rates are designed to pay QFs for capacity during the entire 10–year Schedule PP term where DEC's and DEP's biennial IRP identifies that a future capacity need can be avoided by QF power. This assures that the QF will receive a minimum revenue stream based on the value of its capacity and will receive a more accurate avoided energy price that better aligns the rate paid by the utility with incremental alternative cost of producing or buying the power delivered by the QF. The Commission finds this to be reasonable and fully consistent with PURPA's mandate that a just and reasonable rate for consumers shall not exceed the incremental cost to the electric utility of alternative electric energy. 16 U.S.C. § 824a-3(b); (d).

The Commission likewise does not find that the intervenors have set forth sufficient evidence showing that the 2-year reset is contrary to PURPA because it might result in some QF developers having to alter the way they have traditionally financed contracts for North Carolina QFs. For the most part, the intervenors' testimony consisted of conclusory predictions that QF developers would simply be unable to obtain financing for 1 MW and less projects under the Companies' proposed standard offer. Witness Strunk, for example, testified that the 2-year reset may result in developers having less time to recover their capital investment, taking on higher debt levels to finance, investing more of their own equity, or receiving lower cash flows from the project. (Tr. Vol. 6 at 20-23). The Commission agrees that this testimony shows that the 2-year reset may result in less contracted-for revenue for QF developers (as DEC/DEP are only fixing the energy rate for two years and the capacity rate for the full 10 years), but it not persuaded that it renders DEC/DEP's proposed standard offer contrary to PURPA.

Moreover, the record in this proceeding showed that other states offer either 1-year PPAs or shorter-term "variable" rates under PURPA. Tennessee, Alabama, and Mississippi all have approved minimum standard offer terms of one year, which is far less than what DEC and DEP propose in this proceeding. (Tr. Vol. 2 at 354). Additionally, according to NCSEA Witness Johnson, Alabama, Arkansas, Florida, Kentucky, Louisiana, Maryland, and Virginia offer variable rates rather than long-term fixed rates. (Tr. Vol. 7 at 135, 334). The record evidence is compelling that North Carolina has become an outlier both in terms of its PURPA implementation as well as in fostering surging solar QF development, as compared to those states. Accordingly, the Commission finds that DEC/DEP's proposal is not as conservative as the standard offer PURPA implementation in many other states in the Southeast, and is a reasonable step in light of current economic and regulatory circumstances existing in North Carolina.

The Commission also disagrees that the intervenors have shown that a 2-year reset of energy rates would result in contracts that would not attract investment because the energy rates were not "fixed" over the duration of the contract. The Commission believes that the fixing of capacity rates over the full 10-year term of the contract should alleviate this concern. Moreover, as noted by Witness Bowman, the annual forecasted avoided energy and capacity filings required by 18 C.F.R. § 292.302 allows for QF investors to evaluate the utility's longer-term need for capacity and forecasted cost of energy, because it requires that the utilities biennially file forecasted electric utility system cost data for both energy and capacity with the Commission. QFs and their investors can use this data to evaluate future avoided costs. *Order No. 69*, 45 Fed. Reg. at 12,232. QFs and their investors should also have confidence that the Commission will continue to meet its responsibility to implement the must purchase obligation consistent with the requirements of FERC's PURPA regulations, including establishing just and reasonable avoided energy rates in future biennial proceedings.

Notably, in response to intervenors' concerns, DEC/DEP have also proposed that, in addition to the 2-year energy rate reset option, QFs be allowed to elect the option of having energy rates fixed over the 10-year terms of the PPA. These rates would be fixed at the Energy Credit rates that DEC and DEP filed on their Schedule PP and Schedule PP-3, respectively. The Commission agrees with Witness Bowman that the biennial reset of the avoided energy component was designed to closely align future avoided energy cost payments with DEC/DEP's actual avoided cost of energy, whether that cost is increasing or decreasing. QFs selecting this option could benefit, therefore, if energy prices began to rise. However, the Commission also agrees that to the extent QF developers prefer to fix their current energy prices for the full 10-year term, DEC/DEP's proposal presents a reasonable, interim option that will protect customers from the long-term forecast risk by relying on near-term energy commodity prices underlying the 2-year avoided energy rate, especially if significant QF development continues under the new standard offer rates approved in this proceeding. Based upon the foregoing, the Commission finds and concludes that the Companies' proposal is a just and reasonable interim solution that appropriately restores the balance between encouraging development of QFs 1 MW and less, and protecting customers from the risk of overpayment due to deviations in the forecasted versus actual commodity prices. With respect to this determination, the Commission notes DEC/DEP Witnesses Bowman's and Snider's testimony that approximately 1,100 MW of standard offer QF projects currently under development have established LEOs that locked them into the avoided cost rates approved by the Commission in prior dockets, which should allow significant QF development to continue in the near term as the QF market evaluates the proposed new avoided cost rate design. (Tr. Vol. 2 at 225, 337). To this end, the Commission further concludes that the Companies should reevaluate this rate design option in the next biennial avoided cost proceeding along with the alternative options such as linking rates to a fuel index or including a band or collar on avoided energy rates as proposed by Public Staff Witness Hinton.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 5

The evidence supporting this Finding of Fact is found in DEC/DEP's Joint Initial Statement and DNCP's Initial Statement, the direct and rebuttal testimony and exhibits of DEC/DEP Witness Snider, the testimony of DNCP Witness Petrie, the testimony of NCSEA Witness Johnson, and the testimony of Public Staff Witness Hinton.

DEC/DEP's Joint Initial Statement emphasized that DEC's and DEP's customers are now obligated to pay excess long-term costs due to the recent trend in declining energy markets over the past several years where actual incremental system marginal energy costs have been significantly lower than prior forecasts in earlier avoided cost filings. For non-hydroelectric QFs, DEC/DEP proposed to mitigate the longer-term commodity price forecast risk through the modified Schedule PP 10-year avoided cost rate structure that included biennially resetting avoided energy rates. However, in light of the State policy set forth in G.S. § 62-156 and the Hydro Stipulation, DEC/DEP proposed to continue offering fixed 5-, 10-, and 15-year term standard offer rates for run-of-river hydro QFs without storage capability, as set forth in Schedule PP-H. For purposes of calculating these longer-term avoided energy rates, DEC/DEP relied upon 10 years of forward market natural gas pricing data followed by a transition to DEC/DEP's fundamental natural gas forecast of spot prices in year 11. This methodology was consistent with DEC's and DEP's approach to forecasting future natural gas commodity prices in DEC's and DEP's respective 2016 integrated resource plans ("IRP") filed on September 1, 2016, in Docket No. E-100, Sub 147.

DNCP's Schedule 19-FP proposed a fixed 10-year avoided energy rate, which was also based upon the same approach to forecasting future natural gas commodity prices that DNCP relied upon in developing its 2016 IRP. Specifically, DNCP's 10-year avoided energy rate calculation incorporated 18 months of estimated forward market prices for fuel, PJM Interconnection ("PJM") power, and emissions allowances followed by an 18-month transition period from the forward market prices to its fundamental commodity price forecast obtained from consulting firm, ICF International, Inc. ("ICF"). After 36 months, DNCP then relied exclusively upon ICF's commodity price forecasts for the remainder of the 10-year term. DNCP relied upon updated ICF forecast data obtained as of early October 2016 versus the prior ICF fundamental forecast data used in DNCP's May 2016 IRP. (Tr. Vol. 5 at 248).

Public Staff Witness Hinton testified that while he believed most of DEC/DEP's and DNCP's inputs into their respective avoided energy cost calculations were reasonable, he had concerns with DEC/DEP's approach to developing its price forecast for natural gas. Specifically, he testified that fuel price forecasts are often the most influential factor in calculating avoided energy costs, and cited to the Public Staff's position and the Commission's determination in Sub 140 that DEC/DEP should limit reliance on forward market data to no more than 5 years before transitioning to fundamental forecast data. (Tr. Vol. 8 at 47-48). Witness Hinton asserted that use of 5 years of forward market prices is reasonable and appropriate because the market for these contracts is relatively liquid; whereas, 10-year futures are relatively illiquid. He also suggested that forward market prices can change as futures traders respond to temporary conditions while fundamental price forecasts reflect a more measured and tempered response to expected changes in the natural gas market. (Tr. Vol. 8 at 49). Witness Hinton also argued that DEC's and DNCP's natural gas commodity price forecasts would have been more comparable and reasonable if DEC has relied upon only five years of forward market data. (Tr. Vol. 8 at 50).

NCSEA Witness Johnson also expressed concern about DEC/DEP's use of 10 years of forward market price data for purposes of its IRP analyses and in calculating avoided energy costs. He explained that forward market data is typically obtained from futures markets where traders are buying and selling specialized legal rights to purchase or sell a specified volume of a commodity on a specific future date, but that these market transactions do not typically result in actual physical delivery of the commodity. He further testified that the forward market tends to be more active, or liquid, for contracts in the relative near future, and that while price quotes can be obtained for dates farther into the future, that data is not as meaningful or reliable as the market data for the immediate near term. (Tr. Vol. 7 at 241-43). Witness Johnson also pointed to Duke Energy subsidiary, Duke Energy Florida's (DEF) reliance on a recent Duke Energy fundamental forecast to support investment decisions and longer-term planning for that utility. Specifically, he highlighted DEF testimony in 2015 that DEF's fuel procurement group relies upon three years of New York Mercantile Exchange (NYMEX) forward market quotes followed by a two-year transition to Duke Energy's long-term fundamental forecast. (Tr. Vol. 7 at 250). Witness Johnson also suggested that the March 2017 Energy Information Administration (EIA) long-term fundamental forecast was also reasonable for DEC, DEP, and DNCP to use for planning purposes. (Tr. Vol. 7 at 255-56). He recommended the Commission reject the use of forward market data for anything more than the near-term future, and require DEC and DEP to either use DNCP's blending approach or to require use of the approach relied upon by DEF in 2015 where forward market data would be used for the first three years, followed by a brief two-year transition period of blended prices to the long-term fundamental forecast of prices, and after year five rely entirely on the EIA forecast, or Duke's long-term fundamental forecast, for all subsequent years. (Tr. Vol. 7 at 256).

Witness Johnson also criticized DNCP's decision to update its ICF fundamental forecast to rely upon more current commodity cost data and recommended that DNCP be required to rely on either the EIA fundamental forecast or the same ICF fundamental forecast DNCP used in submitting its 2016 IRP. (Tr. Vol. 7 at 256).

In rebuttal testimony, DEC/DEP Witness Snider extensively rebutted Public Staff Witness Hinton's and NCSEA Witness Johnson's recommendation to rely more heavily upon fundamental forecast data in setting DEC's and DEP's Schedule PP-H rates. He first provided context for DEC/DEP's more recent reliance on natural gas forward market data, explaining that by 2014, changes in the United States natural gas markets and the rapid increase in natural gas production due to technology advancements had created longer range options for purchasing natural gas. At this time, DEC/DEP began requesting quotes for 10-year purchases of natural gas forwards from various brokerage firms based upon these longer range forward market options. Since the Sub 140 proceeding in 2014, DEC/DEP have developed both Companies' 2015 IRP updates as well as their 2016 biennial IRPs based upon 10 years of forward market price data transitioning to fundamental forecast-derived data in year 11. (Tr. Vol. 2 at 246).

Witness Snider analyzed the historic 10-year levelized natural gas forecast assumptions from the DEC/DEP IRPs and avoided cost proceedings dating back to 2012 to show that prices had dropped 40% since 2012, and, more importantly, to show how fundamental price forecasts were lagging the market prices in response to the recent structural changes in the natural gas market. He explained that fundamental forecasts take significant time to develop and are often only released by research firms once or twice per year; therefore, fundamental forecast data can be well over a year old by the time avoided cost rates go into effect. Witness Snider then emphasized the significant impact that relying on stale or lagging natural gas fundamental forecast data can have on forecasted avoided costs in this proceeding, pointing out that DEC/DEP's fundamental forecast natural gas price estimates are at least $l/MMBtu higher than the actual market prices starting in 2020. (Tr. Vol. 2 at 248). Witness Snider also testified that the Commission's mandate in Sub 140 requiring DEC/DEP to rely upon fundamental natural gas commodity price data after year 5 of the long-term avoided costs rates has been the main driver along with the continuing decline in natural gas commodity prices of the current disconnect between DEC/DEP's current actual marginal system operating costs and the significantly higher avoided energy rates approved in the Sub 140 Phase II proceeding that became effective in March 2016. (Tr. Vol. 2 at 233).

Witness Snider also responded to Witnesses Hinton's and Johnson's arguments regarding forward markets lacking liquidity 10 years into the future by actually demonstrating market liquidity through a 10-year purchased forward gas contract, executed April 5, 2017, for 2,500 MMBtu/day of natural gas forwards through 2026. He testified to his experience that long-dated forward contracts are liquid and transactable and may be purchased over-the-counter directly with large financial institutions and other firms rather than traded on the NYMEX. He explained that it is an incorrect perception that liquidity does not exist in the long-dated forward markets as demonstrated by DEP's 10-year purchase of a 2,500 MMBtu/day natural gas forward position. Witness Snider also explained that this forward market transaction provides a tangible price point for the natural gas market over the equivalent period of the 10-year PP-H hydro rate, and that the 10-year levelized price of this purchased gas is approximately 6% lower than the forward market prices used in establishing DEC/DEP's November 2016 proposed avoided cost rate and approximately 20% lower than the 5-year market plus 5-year fundamental forecast blend of 10-year prices recommended by Public Staff Witness Hinton. (Tr. Vol.

2 at 250, 253).

Witness Snider also testified that he disagreed with Witness Hinton's assertion that reliance upon fundamental forecast data is more appropriate than use of actual market prices. He explained that QF purchase power transactions similarly represent significant forward purchased power obligations on behalf of customers, totaling more than $3 billion dollars today. DEC/DEP may either purchase fuel or purchase power, or both, to satisfy future customer energy needs, and PURPA requires customers to be held indifferent between the two. Witness Snider testified that use of fundamental price forecasts, rather than a transactable gas price, leads to avoided energy rates that are inconsistent with this indifference standard that is a bedrock principle of PURPA. Witness Snider also testified that, consistent with the Commission's prior direction in the Sub 140 Phase II Order, DEC/DEP's fuel forecasting methodology of using 10 years of forward market data with a blending to fundamentals starting in year 11 is the same methodology used in both the 2015 IRP and 2016 IRP filings for DEC and DEP.'. Third, Witness Snider also explained that Witness Hinton's recommendation to rely upon fundamental forecast data was in conflict with Witness Hinton's own alternative recommendation to consider offering QFs avoided energy rates based on a composite commodity price index. He explained that the gas commodity price index is a market-based price and QF's ability to enter into a hedging transaction to fix their future revenues under this structure could only occur at the prevailing forward market price for natural gas and not at fundamental forecast-derived price levels that are different from the market price. Witness Snider explained that by offering QFs a transactable forward price above the prevailing natural gas market, the implicit result of Witness Hinton's position would be to subsidize QFs while transferring significant price risk to North Carolina consumers. (Tr. Vol. 2 at 254-55).

Witness Snider also rebutted Witness Hinton's assertion that DEC/DEP's and DNCP's fundamental forecasts were more comparable than DEC/DEP's reliance on 10 years of market prices. Witness Snider explained that at any point in time only a single forward market exists for natural gas, while a wide range of fundamental price forecasts are available, as shown by the deviation between DEC/DEP's and DNCP's fundamental forecasts. (Tr. Vol. 2 at 256).

During the hearing, Witness Snider testified to the difference between a transactable market-based forward price versus a longer-term spot forecast of commodity price beyond the liquid market. (Tr. Vol. 4 at 83-84). He explained that accuracy and appropriateness were key considerations that support relying upon forward market price data in a transactable market versus fundamental forecast spot pricing. With regard to accuracy, Witness Snider emphasized that only a single transactable market price exists while multiple spot forecast prices may exist based upon differing fundamental forecasts. Further, reliance on lagging or "stale" fundamental forecast pricing has proven to be inaccurate over the past few years and has led to a systematic overpayment to QFs. (Tr. Vol. 4 at 88, 90, 106, 116). He testified that DEC/DEP had also addressed liquidity concerns with DEC/DEP's use of long-term forward commodity price quotes, as raised in Sub 140, by actually transacting in the forward market to accurately show the actual 10-year forward market price of natural gas. (Tr. Vol. 4 at 88). With regard to appropriateness, Witness Snider explained that fundamental forecasts are intended to act as a guide to future spot prices beyond the liquid transactable curve, but are never intended to be used as a transactable price in the presence of a transactable market. (Tr. Vol. 4 at 93). He also explained how relying on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage of the market prices and result in QF generators flocking to a region to take advantage. (Tr. Vol. 4 at 89, 100, 121).

Witness Snider also testified that contracting for QF power is also a forward market transaction committing the utility to purchase from a QF at a fixed price years into the future, and that the utility can either buy the power or buy the commodity and should be indifferent between the two. (Tr. Vol. 4 at 101, 104, 118). DEP's recent April 5, 2017 natural gas forward transaction procured equivalent gas to approximately 50 MW of solar QF generation at a six percent lower levelized price than the forward market commodity price used in DEC/DEP's rates filed in November. Witness Snider also identified that PURPA allows the QF the option to select pricing at the time energy is delivered if the QF believes the future spot price will be higher than the transactable forward market. (Tr. Vol. 4 at 102, 119).

During examination by Public Staff, Witness Snider agreed that NYMEX and the Intercontinental Exchange are exchange markets where shorter term natural gas futures are traded. However, he explained that the commodity market has evolved where long-dated future natural gas trading is occurring through bilateral transactions with numerous financial institutions, and DEC/DEP's experience is that a very liquid, long-dated market exists where quotes and transactions with multiple counter-parties can occur at a market price 10 years into the future. (Tr. Vol. 4 at 99-100, 117, 120). Witness Snider testified that DEC/DEP's continued and consistent reliance on 10 years of forward market data in their last four regulatory filings, including IRP and biennial avoided cost filings, as well as the April 5, 2017 10-year forward market transaction has demonstrably demonstrated a liquid and transactable market. (Tr. Vol. 4 at 108-109, 117).

During examination by DEC/DEP, Witness Hinton conceded that he did not have experience and had not investigated the bilateral forward market transactions discussed by DEC/DEP Witness Snider, and suggested that the bilateral forward market price may be an accurate price but at lesser volume than an exchange trade on the Intercontinental Exchange or NYMEX. (Tr. Vol. 8 at 163, 168-170). He also agreed that DEC/DEP had consistently relied upon 10 years of forward marked data for both IRP and biennial avoided cost filings since Sub 140. (Tr. Vol. 8 at 167). Witness Hinton also agreed that the Public Staff's recommendation to rely upon DEC/DEP's fundamental forecast would significantly increase the levelized avoided energy price paid for QF power compared to the most recent 10-year forward market purchase completed by DEP on April 5, 2017. (Tr .Vol. 8 at 219-221).

Discussion and Conclusion

The Public Staff's investigation generally found that DEC/DEP and DNCP's inputs into their respective avoided energy cost calculations were reasonable with one exception. The sole issue challenged by the Public Staff is DEC/DEP's reliance on 10 years of forward market natural gas commodity price data before transitioning to pricing based upon DEC/DEP's long-term fundamental natural gas commodity forecast data in year 11.

In the 2014 Sub 140 Phase II proceeding, the Commission recognized the changing nature of the natural gas market and advised the Utilities that recognition of these changing markets is appropriate in the context of both IRP and biennial avoided cost proceedings. *Sub 140 Phase II Order* at 27. In that proceeding, DEC/DEP first proposed to rely upon 10 years of forward market natural gas pricing in calculating long-term avoided energy rates. However, at that time, DEC/DEP's most recent 2014 biennial IRPs had relied upon only 5 years of forward market data. In requiring DEC/DEP to recalculate their avoided energy rates using commodity price forecasts utilized in their 2014 IRPs, the Commission advised the Utilities as follows:

> To the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts, it is appropriate to require that these changes should be made in the Utilities' biennial integrated resource plans (IRPs), and the same approach should be used in their biennial avoided cost filings for that same year.

Sub 140 Phase II Order at 7 (Finding of Fact 9); 28. Since the Sub 140 Phase II proceeding, DEC/DEP have consistently relied upon the same methodology in their 2015 IRP updates as well as their 2016 biennial IRPs as well as this proceeding to determine future natural gas commodity pricing. DEC/DEP have now repeatedly obtained transactable quotes to establish 10-year forward market natural gas pricing to support their 2015 and 2016 IRPs and have also now obtained both transactable quotes as well as entered into a 10-year forward market transaction in support of their biennial avoided cost rates. The Commission finds that DEC and DEP have taken appropriate steps to follow the Commission's prior guidance regarding methodological consistency between their IRPs and future avoided cost rate calculations.

More significantly, however, the Commission finds that DEC/DEP have presented compelling testimony regarding the accuracy and appropriateness of their reliance on 10 years of forward market data in setting their Schedule PP-H 10-year and 15-year avoided energy rate calculations. The Public Staff's primary concerns related to liquidity and accuracy of forward natural gas commodity pricing out longer than 5 years in to the future. Public Staff Witness Hinton testified that his investigation of natural gas trading on the Intercontinental Exchange trading platform did not find liquid forward exchange market-based transactions out longer than 5 years in to the future. However, Witness Hinton also testified that he had not investigated the liquidity of 10-year bilateral transactions with financial institutions relied upon by DEC/DEP Witness Snider in determining the current transactable forward market price of natural gas nor did he dispute the price accuracy of DEP's recent 10-year purchased forward gas contract, executed April 5, 2017. (Tr. Vol. 8 at 163, 168-170). The Commission finds DEP's recent forward market-based transaction to be compelling evidence of both the liquidity and accuracy of the 10-year forward gas market pricing. Notably, Witness Snider also testified that this levelized price transacted-for purchased gas is approximately 6% lower than the forward market prices used in establishing DEC/DEP's November 2016 proposed avoided cost rate and approximately 20% lower than blended 10-year prices recommended by Public Staff Witness Hinton. The Commission agrees with DEC/DEP that the lagging nature or "staleness" of fundamental commodity pricing forecasts over the past few years in the face of rapidly changing natural gas markets has contributed to a systematic over-statement of DEC/DEP's avoided costs that should be remedied going forward, especially in light of the current economic and regulatory circumstances discussed in this Order.

The Commission also finds DEC/DEP's reliance on transactable forward market price data to be more consistent with PURPA's objectives that customers be held indifferent between the utility purchasing QF power or generating or purchasing power from another source. 16 U.S.C.S. § 824a-3(b). In enacting Section 210 of PURPA, Congress directed that rates for QF purchases shall not exceed the utility's incremental cost of alternative electric energy, which is "the cost to the electric utility of the electric energy which, but for the purchase from [the QF] such utility would generate or purchase from another source." 16 U.S.C.S. § 824a-3(d). DEC/DEP have presented evidence in both Sub 140 and now in this proceeding that the 10-year forward natural gas market is reasonably liquid and transactable, such that DEC/DEP can derive a forward market price for natural gas that could be purchased and then used to generate alternative electricity to buying QF power. Further, in this proceeding, DEP has now actually transacted in the forward market to contract for 2,500 MMBtu/day through a 10-year forward position extending through 2026. As Witness Snider testified, the April 5, 2017 natural gas forward position contractually commits DEP to purchase natural gas fuel that will allow DEP to generate electricity equivalent to a 50 MW block of QF solar.

The Commission also agrees with Witness Snider that setting avoided energy rates based on natural gas commodity prices higher than the forward market would potentially create arbitrage opportunities where natural gas cogenerators could procure fuel at the lower forward market price and then sell power at the higher avoided energy rate. There is also no evidence in the record to explain how DEP/DEC would be prudent in transacting to purchase long-dated natural gas fuel (which is the equivalent of long-dated QF power) at higher fundamental forecast-derived prices in the face of a reasonably liquid and transactable forward market at a lower price. Accordingly, the Commission finds that reliance on fundamental forecast-derived natural gas commodity pricing that is higher than transactable forward-market derived natural gas commodity pricing would be inconsistent with the customer indifference principle under PURPA and would result in avoided cost rates that exceed the incremental costs DEC/DEP would otherwise incur to generate or buy alternative power, which would not be just and reasonable to DEC's and DEP's customers as required by PURPA. 18 C.F.R. § 292.304(a).

The Commission also notes that the FERC's regulations implementing PURPA do not require QFs to contract to sell power based upon current forward market price of natural gas if they perceive a fundamental forecast of future natural gas commodity prices (whether DEC/DEP's, DNCP's, or the EIA forecast data highlighted by NCSEA Witness Johnson) may be more accurate and that future prices will exceed the current forward market price of natural gas. In addition to the option of selling "as-available" energy, a QF that commits to deliver energy over a future specified term also has the option of fixing avoided energy rates either prior to the beginning of the specified term or at the time the energy is delivered by the QF to the utility. 18 C.F.R. § 292.304(d)(2)(i)-(ii). Therefore, if the QF believes that the higher fundamental forecast-derived avoided cost rates will prove to be more accurate than the current forward market, then the QF has the right under PURPA to elect to obtain DEC/DEP's actual avoided energy costs at the time the energy is delivered.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that DEC/DEP and DNCP have each carried their burden to show that their respective methodologies to calculate their longer-term avoided energy rates for DEC/DEP Schedule PP-H and PPH-1, respectively, and DNCP Schedule 19-FP are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 6-8

The evidence supporting these findings of fact is found in DEC/DEP's Joint

Initial Statement, the direct and rebuttal testimony of DEC/DEP Witnesses Bowman and Snider, Public Staff Witness Hinton, SACE Witness Vitolo, and NCSEA Witness Johnson.

In the Joint Initial Statement, DEC/DEP indicated that they had calculated their avoided capacity costs to account for each utility's relative need for additional generating capacity as determined by their respective IRPs. Witness Bowman and Witness Snider both testified that PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for capacity and energy provided by the QF, the utility would be forced to generate or purchase elsewhere to serve its customers. If the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, then the QF should not be compensated for providing that benefit. In support of her testimony, Witness Bowman cited *City of Ketchikan*, a FERC decision that held that while a utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should include only payments for energy or capacity that the utility can use to meet its total system load.[12] She also cited N.C. Gen. Stat. § 62-156(b)(2), which states that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity which could be displaced." (Tr. Vol. 2 at 356). Witness Bowman additionally acknowledged that the Commission had cited FERC's *Hydrodynamics* decision[13], as supportive of its previous determination that the Utilities should not include zeros in the early years when calculating avoided capacity rates. She distinguished *Hydrodynamics* from the circumstances of this proceeding, however, by noting that

[12] *City of Ketchikan, Alaska*, 94 FERC ¶ 61,293 (2001) ("*Ketchikan*").
[13] *Hydrodynamics,* 146 FERC ¶ 61,193 (2014) ("Hydrodynamics").

Hydrodynamics pertained to a limit on installed capacity purchases by a utility and did not pertain to a utility proposal to recognize a capacity value only in years where the utility's IRP showed a need for such capacity. (Tr. Vol. 2 at 365-67).

Witness Snider also recommended that the Companies' relative need for incremental generating capacity should be accounted for in calculating its avoided capacity rates. Prior to the year in which the next generation unit is needed to serve system load, the utility does not have a capacity need to avoid. Thus, Witness Snider explained, the calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need. Witness Snider then confirmed that the first capacity need for both Companies occurs in the 2022-2023 timeframe, as shown their 2016 IRPs. (Tr. Vol. 2 at 220-21). He also clarified that QFs under the standard offer tariff will receive capacity payments in years prior to the Companies' first capacity need because the QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs. In sum, with these proposed adjustments, Witness Snider believed that DEC/DEP's customers were paying capacity payments that were equal to the economic value of an associated avoided capacity cost. (Tr. Vol. 2 at 222-23).

Public Staff Witness Hinton testified that, contrary to the Public Staff's position in prior avoided cost proceedings, he believed that under the current circumstances, making capacity payments to QFs only when additional capacity is needed on the system is now appropriate. Witness Hinton first explained that the theory underlying the peaker method is that if the utility's generating system is operating at the optimal point, then the cost of a peaker (a combustion turbine, or "CT") plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. While Witness Hinton continued to support application of the peaker methodology and did not take the position that the current level of QF generation had led to a severe deviation from optimality, he did highlight the growing likelihood of severe and persistent deviations from optimality if a substantial number of the solar facilities in the Utilities' interconnection queues are built. He also testified that the rapid increase in solar generation in DEP's service area has contributed to planned reserve margins over the next three years between 25% and 27%, and that future substantial imbalances in capacity may continue to challenge the utilities' least cost planning. Witness Hinton explained that while capacity value is normally recognized under the peaker method from the first day of QF operation, regardless of the utilities' needs for additional capacity, the practical reality of the addition of significant quantities of solar generation, especially in the DEP service area, challenges this assumption and warrants a departure from a traditional application of the peaker method. Witness Hinton also explained that by restricting the payment for capacity until the IRP established a capacity deficiency will minimize risk to ratepayers while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market. (Tr. Vol. 8 at 25-31).

SACE Witness Vitolo and NCSEA Witness Johnson opposed DEC/DEP's proposal to make no avoided generation capacity payments in years when their respective IRPs did not show an actual need for capacity. They both recommended that the Commission maintain its decision from the Sub 140, Phase 1 proceeding. Witness Vitolo indicated that doing so was a deviation from the peaker methodology. He cited evidence offered in the Sub 140 proceeding tending to show that the buildout of large-scale utility capacity is “lumpy” in character and therefore utilities build far more generation than is required in a subsequent year, which results in ratepayers paying more for generation capacity than is needed until demand catches up with the addition. (Tr. Vol. at 47-50). NCSEA Witness Johnson echoed Witness Vitolo’s arguments regarding the “lumpiness” of utility generation additions. He indicated that utilities build large plants because of the economies of scale. Thus, if the utilities need to add capacity at the rate of 100 MW per year, it will not add a 100 MW plant every year. Instead, it will add a 600 MW plant in a single year and, five or six years later, add another 600 MW plant. Witness Johnson testified that the economic theory underlying the peaker method was that long-run capacity payments exist in every year, not absent in some years and present in others. Thus, the long-run cost of capacity is the same, even when no capacity is planned. As such, Witness Johnson concluded that because the utility is allowed to recover its capacity costs during “zero” years, just after a “lumpy” new plant has been added, to avoid discrimination, the QF should be treated the same and be paid for capacity even in “zero” years, even if the QF has the effect of pushing the reserve margin higher than required. (Tr. Vol. 7 at 289-96).

In his rebuttal testimony, Witness Snider countered Witness Johnson’s claim that the Companies’ proposal to account for capacity needs in calculating avoided capacity rates was discriminatory toward QFs. He pointed out that Witness Johnson mistakenly assumed that utilities “overbuild,” resulting in excess capacity that is fully recoverable. Instead, Witness Snider explained, a large generation unit is selected in a resource plan because it is the most economic resource option for consumers. When building larger units, the Companies achieve economies of scale and operating efficiencies that provide a more economic and efficient solution than smaller increments of generation. Smaller increments of generation that put the utilities at their minimum reserve margin targets are not economically optimal for customers, especially when the utilities cannot control and dispatch the generating resource being built. Witness Snider acknowledged that the IRP and CPCN processes often result in periods of reserves in excess of reserve targets, but this selection of a larger resource is done after careful consideration of all the costs and benefits of smaller scale generation versus larger scale generation. Under any circumstances, Witness Snider concluded, it harms customers to pay for QF capacity that is not actually avoiding a capacity need.

On cross-examination, Witness Snider explained that DEC/DEP's proposal was consistent with the peaker method, which does not require that payments be made for capacity when no capacity is needed. Witness Snider further explained that including zeros for years in which the utility does not have an avoidable need for capacity results in avoided cost rates that compensate the QF for the full cost of a CT, plus the system marginal cost in the first year of need for capacity. (Tr. Vol. 3 at 64-65). Witness Snider also described an example of integrated resource planning for DEC/DEP's own generation in practice when DEC had zero need for capacity. Witness Snider acknowledged that the Lincoln County CT did not appear in DEC's IRPs prior to requesting Commission approval through its CPCN proceeding. He explained, however, that DEC recognized it wanted to build capacity early so DEC essentially gave the Lincoln County CT zero capacity value in the first years until DEC had a need. It still had to be the most prudent and economic option for customers in order to justify it before the first year of need. (Tr. Vol. 3 at 69).

Discussion and Conclusions

The Commission agrees with DEC/DEP Witnesses Bowman and Snider and Public Staff Witness Hinton that the avoided capacity cost calculation methodology including the peaker method should account for the relative need for generating capacity. The Commission finds that DEC/DEP's customers should not be obligated to pay for capacity value in years where there is no need for additional capacity.

As an initial matter, the Commission agrees with Witnesses Bowman and Snider that one principal aspect of PURPA is that QFs should be fairly and reasonably compensated for the incremental capacity and energy costs that, but for the capacity and energy provided by the QF, the utility would be required to generate or purchase elsewhere to serve its customers. PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need. Both *Order No. 69* and subsequent FERC decisions have reinforced this point, specifically *Ketchikan.*[14] In *Ketchikan*, the FERC determined that while the utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should only include payment for energy or capacity that the utility can use to meet its total system load.[15] North Carolina law also contemplates this concept in that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity *which could be displaced.*"[16] The Commission finds that Witness Snider's approach to calculating avoided capacity seeks to effectuate this concept in practice by providing avoided capacity credits to QFs based upon the actual capacity being avoided

[14] *Ketchikan*, 94 FERC ¶61,293 at 18 (2001)..
[15] *Id*.
[16] N.C. Gen. Stat. § 62-156(b)(2) (emphasis added.).

by the purchase of power from the QF.

The Commission acknowledges that it concluded differently when reviewing a similar proposal in Sub 140 Phase I, in part based upon its interpretation of the FERC's decision in *Hydrodynamics*. The Commission notes, however, that *Hydrodynamics* did not pertain to a utility's proposal to recognize a capacity value only in years where the utility's IRP showed a need for capacity. Instead, *Hydrodynamics* pertained to a limit on installed capacity purchases by a utility from wind QFs. Upon review, the FERC found that a 50 MW cap on QF-provided capacity prevented certain wind QFs from receiving any fixed, long-term compensation for capacity. Citing its decision in *Ketchikan*, the FERC stated in *Hydrodynamics* that avoided cost rates need not include the cost for capacity when the utility's demand or need for capacity is zero. The FERC concluded, however, that based upon the record before it, that cap on installed capacity did not have a "clear relationship" to the utility's "actual demand" for capacity. In the current proceeding, however, as explained by DEC/DEP Witness Snider and supported by the Public Staff's Witness Hinton, the Companies' IRPs clearly provide that they do not have an actual demand for capacity until the 2022-2023 timeframe. (Tr. Vol. 2 at 221, Tr. Vol. 8 at 30-31). Thus, 'DEC/DEP's proposal to not include value for capacity until the first year they each respectively need it has a "clear relationship" to the utility's actual demand. Therefore, the Commission concludes that its determination in this matter is consistent with both *Ketchiken* and *Hydrodynamics*.

The Commission is not persuaded by SACE Witness Vitolo and NCSEA Witness Johnson that inclusion of no capacity value in avoided capacity rates when the utilities do not show a need for capacity is discriminatory under PURPA. Moreover, the record in this proceeding shows that the utilities add or procure generation under very different circumstances and recover their costs for that generation very differently than QFs. The Commission agrees with Witness Snider that utility capacity additions are selected after careful consideration of all the costs and benefits of smaller scale generation over larger scale generation. Additionally, the Commission does not accept that because a utility may have a long-term capacity need, the utility is required to pay for capacity over the contract term. Put simply, the Commission believes that the FERC has indicated that PURPA was not intended to force a utility and its customers to pay for capacity that they do not need. To do so would violate PURPA because it would result in the utility making payments in excess of its avoided costs. The Commission further agrees with Public Staff Witness Hinton that restricting the payment until the IRP has established a capacity deficiency that will minimize the overpayment risk to ratepayers, while providing a reasonable level of financial compensation for avoided cost and send a better price signal to the market.

Based on the foregoing, the Commission finds and concludes that DEC and DEP may calculate their avoided capacity rates recognizing capacity value starting in the first year of actual need as shown in the Companies' IRPs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-10

The evidence supporting these findings of fact is contained in the direct and rebuttal testimony of DEC/DEP Witness Snider, the testimony of Public Staff Witness Hinton, the testimony of SACE Witness Vitolo, the testimony of NCSEA Witness Johnson, and the testimony presented at the evidentiary hearing.

Witness Snider testified that the Companies had commissioned Resource

Adequacy Studies that were presented in the 2016 IRPs. The high penetration of solar resources that have connected to the Companies' transmission and distribution systems in the past 2-3 years, along with the high volume of solar resources currently in the interconnection queue, was one driver of the studies; the significant load response to cold weather experienced in 2014-2015 winter periods was the other. (Tr. Vol. 2 at 209).

Witness Snider testified that, in the past, the Companies' annual peak demands were projected to occur in summer. In addition, the Companies' generating fleets, especially gas-fired CTs and combined-cycle units, have greater output during winter periods compared to summer periods. Thus, summer load and resources have driven the timing need for new resource additions, and a summer reserve margin target provided adequate reserves in both the summer and winter periods and was sufficient for overall resource adequacy. (Tr. Vol. 2 at 210).

Witness Snider explained, however, the load and resource balance has changed dramatically in the past two to three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. He further explained that solar resources contribute significantly more to the summer afternoon peak than they contribute to winter morning peak. Therefore, Witness Snider stated, the 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. As such, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load and resources now drive the timing and need for new capacity additions. (Tr. Vol. 2 at 210).

Witness Snider explained that the Companies increased their minimum planning reserve margin target in the 2016 IRP due to the surging solar penetration and significant winter load response. (Tr. Vol. 2 at 210-11). Solar resources contribute approximately 45% of their nameplate rating at the time of the summer peak, which occurs in the afternoon hours. He noted that the Companies' winter peaks occur in the early morning hours around 7:00 am when solar has no output. The Companies' 2016 IRP reflect a 5% capacity contribution from solar for winter resource planning purposes. Thus, as solar resources increase, the Companies' summer reserve margins increase compared to winter reserves. Witness Snider explained that higher solar penetration is one of the drivers of the shift to winter capacity planning and why the Companies must now plan new resource additions to satisfy minimum winter reserve margins. Planning to a 17% winter reserve margin with growing summer resources will result in an increasing summer reserve margin over time. Witness Snider demonstrated also that the disparity will continue to grow as solar penetration increases. (Tr. Vol. 2 at 216-17).

Witness Snider next explained that 2016 resource adequacy studies showed that approximately 80% or more of the loss of load risk now occurs during the winter period and about 20% during the summer period. This 80/20 winter/summer seasonal weighting was incorporated into the Companies' avoided cost rates in this Docket. (Tr. Vol. at 217-18).

Public Staff Witness Hinton testified that the Public Staff had concerns that the proposed seasonal factors may shift an excessive emphasis toward the winter periods. He agreed that the Companies had experienced significant winter peaks in 2014 and 2015, but he believed that the significant shift of avoided capacity values to winter periods was premature at this time. Witness Hinton testified that DEC/DEP's shift from summer to winter peaking should not diminish consideration of the summer peak, which remains significant. He recommended that DEC/DEP adjust the seasonal weighting to 40% for summer and 60% for non-summer and that the Companies continue to monitor seasonal capacity needs to better inform future seasonal allocation decisions. (Tr. Vol. 2 at 40-42).

SACE Witness Vitolo testified that he also had concerns about the Loss of Load Expectation study that the Companies used for weighting their summertime and wintertime capacity values. He believed it overemphasized “atypical” recent weather experienced in 2014-2015 winters. He also criticized the report because it did not focus on 36 years of historical weather data, but looked at only 5 years instead. Doing so overstated the possibility of reliability challenges in the wintertime as compared to summertime, which has been the case historically. Witness Vitolo recommended instead that the Commission direct DEC and DEP to weigh its summertime capacity at 80% for years 2017 and 2018 in setting avoided capacity rates. (T. Vol. 7 at 54-55).

NCSEA Witness Johnson presented testimony regarding the historic hourly load data for DEC and DEP for the period 2006-2015 to show that the most extreme peaks (86.5%) occurred during the months of June through September, while the remaining 13.5% occurred during the months of December through February. He indicated this data was inconsistent with the Companies’ proposal to allocate 80% of the capacity costs to a broadly defined non-summer period starting in October and ending in May. (Tr. Vol. 7 at 307-15).

Witness Snider responded to these concerns in his rebuttal testimony by explaining that winter capacity planning is distinct from winter peaking, and by highlighting the impact of the addition of solar resources on that planning, DEC and DEP must still "plan" on a winter peak reserve margin criteria as a result of existing and anticipated solar on the system. A summer reserve margin target will no longer ensure adequate reserve capacity in the winter, as winter load and resources now drive the timing need for new capacity additions, as described in the Companies' respective 2016 IRPs. This transition to winter planning, therefore, was essential to ensuring that adequate reserves will be available throughout the year as required to provide acceptable resource adequacy. Witness Snider supported his argument by demonstrating that during the last 5 years, DEC's annual peak has occurred in winter in two out of five years and DEP's annual peak has occurred in winter four out of five years. (Tr. Vol. 2 at 287-88). Based on the 2016 IRPs, the Companies project that DEP's annual peak will occur in the winter for each year of the planning horizon. DEC, however, will be summer peaking until around 2027, when the peak is projected to occur during winter. For both Companies, the winter peaks are projected to grow at a greater rate than summer peaks. Furthermore, Witness Snider reported that the Companies have experienced significant load response to recent winter weather and are continuing to refine the summer and winter peak demand forecasting process. (Tr. Vol. 2 at 287-88).

Witness Snider also disputed Witness Hinton's statement that DEC and DEP were modeled as winter peaking in the 2015 Resource Adequacy Studies. He clarified that DEP's projected winter peaks exceed summer peaks, but DEC's summer peaks exceed winter peaks until 2027. The studies were based on 2019, when DEP is winter peaking but DEC is still summer peaking. Witness Snider emphasized, however, that regardless of when the peaks occur, the Resource Adequacy Studies showed a need for both Companies to shift to winter capacity planning. (Tr. Vol. 2 at 289). Witness Snider further disagreed with Public Staff Witness Hinton's recommendation that the seasonal weighting should be adjusted to 40% for summer and 60% for non-summer for the same reasons. He indicated that the Public Staff was overly focused on the relationship between the Companies' summer versus winter peak demands. Witness Snider projected that additional solar resources will only exacerbate the winter loss of load expectation ("LOLE") concentration. He concluded that the Public Staff's recommendation will also send the wrong pricing signals to developers. (Tr. Vol. 2 at 293-94).

Witness Snider also rebutted Witness Johnson's assertion that DEC/DEP's hourly load data did not support the Companies' seasonal weighting by pointing out that Witness Johnson only considered historic load data and not impacts to reserve capacity in his recommendations. Witness Snider agreed with Witness Johnson that the Companies experience significant summer loads, but he highlighted that summer peaks occur late in the afternoon when solar has some energy contributions as compared to winter where very little solar is available at the time of peak. As a result, summer peak loads are net of solar output compared to winter peak loads. Witness Snider gave two examples of how solar resources actually reduce summer peak loads. First he described the summer and winter peaks for DEC in 2015, a cold winter year. In that year, the winter peak was about 1,200 MW greater than the summer peak. However, once 3,000 MW of solar is added, it results in a winter peak that exceeds the summer peak by 2,400 MW. Additionally, Witness Snider described the impact of solar on summer and winter peaks in 2016, a mild winter year. For that year, the summer peak exceeded the winter peak by about 900 MW. The addition of 3,000 MW of solar, however, results in a winter peak that exceeds the summer peak by about 300 MW. Thus, high penetrations of solar have a dramatic impact on summer versus winter loads. Moreover, there is a greater uncertainty in winter loads as demonstrated during recent winter periods. Witness Snider concluded that this uncertainty coupled with the severe winter load and resource conditions have the greatest impact on system reliability and LOLE. (Tr. Vol. 2 at 289-92).

Witness Snider also responded to Witness Vitolo's criticism of the Resource Adequacy Studies. Contrary to Witness Vitolo's assertion that the Resource Adequacy Studies only included 5 years of weather and load data in its analysis, they included 5 years of weather and load data to develop weather and load relationships that could be applied to all 36 historic weather years that were included in the study. The modeling was done on all 36 historic weather years, not just the last 5. Witness Snider indicated that the Companies will continue to commission new studies as significant changes occur that may impact study assumptions and results. (Tr. Vol. 8 at 294-96).

Finally, Witness Snider testified that although this change in seasonal weighting is important, it has a minimal impact of approximately +/- 1% on the avoided capacity payments for solar QFs. For baseload QFs, it has no impact. (Tr. Vol. 8 at 296-97).

Discussion and Conclusions

The Commission finds and concludes that the record in this proceeding supports DEC and DEP weighting their capacity payments between the winter and summer peak seasons as 80% winter and 20% summer. The Commission further finds that even though the proposed weighting has minimal impact on avoided capacity payments to QFs in this proceeding, it is an important issue because it reflects a significant shift in seasonal loss of load risk and sends the appropriate price signal to QF developers.

Throughout this proceeding, the Commission has heard extensive testimony on how the unprecedented influx of solar resources in North Carolina affects the Companies' operations and planning. With respect to this issue, Witness Snider has sufficiently demonstrated how this influx of solar has a significant impact on summer versus winter peak demands net of solar output. Witness Snider has also effectively highlighted how winter load volatility is significantly greater than summer load volatility. This winter load volatility combined with the impact of solar capacity have resulted in a significant shift of loss of load risk to the winter period. The Commission agrees that the seasonal capacity weighting should be based on seasonal loss of load risk.

The Commission further agrees with the testimony of Public Staff Witness Hinton, NCSEA Witness Johnson and DEC/DEP Witness Snider that the summer peak demands remain significant. However, the Commission does not agree with Public Staff Witness Hinton that the Companies' proposed seasonal factors may shift an excessive emphasis toward the winter peaks. The Commission instead agrees with Witness Snider's rebuttal testimony that a summer reserve margin will no longer ensure adequate reserve capacity in the winter, as winter load and resources now drive the timing for new capacity additions, as described in the Companies' 2016 IRPs. The Commission further agrees that, based on this evidence, the transition to winter planning, through the use of a winter reserve margin target is essential to sure that adequate reserves will be available throughout the year as required to provide acceptable resource adequacy. Thus, the Commission finds that the Companies are appropriately planning to maintain the reliability of their generation systems in winter, based on the influx of solar facilities' contribution to summer peaks and the load response experienced during the recent winter periods. The Commission is additionally persuaded by Witness Snider's testimony and the Companies' Resource Adequacy Study results that demonstrate 80% or more of the loss of load risk is projected to occur in the winter period and the concentration of LOLE in the winter will be further exacerbated as more solar is added to the systems.

The Commission is unpersuaded by Witness Vitolo's criticisms of the Companies' Resource Adequacy Studies regarding the use of historical weather data. As Witness Snider testified, the Resource Adequacy Studies did not only include five years of weather and load data as asserted by Witness Vitolo, but rather the recent temperature and load relationships were applied to 36 historic weather years that were included in the study. The Commission is likewise not persuaded by Witness Johnson's argument that historic summer peak load data does not support the Companies' seasonal weightings. The Commission finds that high penetrations of solar have a significant impact on summer versus winter loads net of solar contributions. The associated impact on reserves and LOLE is dramatic.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that the DEC/DEP seasonal capacity weighting change to 80% winter and 20% summer is appropriate and should be implemented in calculating avoided capacity cost rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this Finding of Fact is contained in DEC/DEP's Joint Initial Statement, the direct and rebuttal testimony of DEC/DEP Witness Snider, Public Staff Witnesses Hinton and Metz, NCSEA Witness Johnson, SACE Witness Vitolo, and the rebuttal testimony of DNCP Witness Petrie.

DEC/DEP's Joint Initial Statement modified the current 1.2 PAF multiplier used to calculate DEC/DEP's Schedule PP avoided capacity rates to a 1.05 PAF multiplier for all QFs other than run-of-river hydro without storage.[17] DEC/DEP stated the current higher PAF of 1.2 results in unjustifiably increased avoided capacity costs being paid to QFs and ultimately paid by customers. DEC/DEP acknowledged that this Commission has previously reviewed adjusting the PAF in the Sub 140 proceeding and determined that a PAF of 1.2 for QFs other than run-of -river hydro was appropriate. However, DEC/DEP requested that the Commission revisit this decision due to changes in economic and regulatory circumstances.

DEC/DEP Witness Snider recommended that the PAF multiplier for non-hydro facilities be reduced from 1.20 to 1.05 to align the PAF with the operational characteristics of a CT. Witness Snider testified that the PAF is intended to make up for a QF's unavailability during the on-peak period when QFs are paid for capacity by increasing the rate the QF is paid during peak hours to account for hours in which it does not operate. Witness Snider acknowledged that DEC/DEP's resources are sometimes unavailable, and it follows that the QFs replacing those resources should not be penalized for the same level of unavailability. Witness Snider testified that when using the peaker methodology to calculate avoided cost rates, the resource a QF is replacing is a CT. He then explained that DEC's and DEP's CT fleet performs at greater than 95% starting reliability, and as such, no PAF greater than 1.05 is warranted. (Tr. Vol. 2 at 222-24).

Witness Snider acknowledged that this Commission declined to adopt a similar

[17] As discussed elsewhere in this Order, DEC/DEP's Schedule PP-H maintains the current 2.0 PAF for run-of- river hydroelectric facilities in accordance with the Stipulation of Settlement entered into between DEC/DEP and the North Carolina Hydroelectric Group, as approved in Docket No. E-100 Sub 140. *See Sub 140 Phase I Order* at 56.

proposal to modify the PAF to 1.05 in the 2014 Sub 140 proceeding. He noted that this Commission determined that arguments presented in that proceeding to modify the PAF were insufficient "at that time," as this Commission found "widespread QF development under the existing framework without adverse impacts to ratepayers." Witness Snider testified that since Sub 140, both DEC and DEP have experienced an unprecedented surge in solar QFs exposing customers to $1 billion in overpayments for energy and capacity. He testified that the approximately $1 billion in overpayments only accounts for QFs that are currently delivering power and does not include approximately 1,100 MW (of 5 MW and less QFs) that are in development or under construction and remain eligible for the avoided cost rates that were calculated in Sub 140 or Sub 136. (Tr. Vol. 2 at 224-25). He also testified that DEC/DEP are unaware of any other jurisdiction except DEC's and DEP's stipulated avoided cost rates in South Carolina (which are derived from the rates calculated in Sub 140) that have recently explicitly or implicitly provided for a PAF multiplier in setting avoided capacity rates. (Tr. Vol. 2 at 225).

Public Staff Witness Hinton provided a brief history of the PAF, stating that in the early stages of PURPA implementation, the Commission approved a capacity credit adjustment based on the utilities' reserve margin of 20%, which was subsequently replaced with the PAF. The Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive capacity payments that the Commission had determined constituted the utility's avoided capacity costs. More specifically, according to Witness Hinton, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate on all peak hours throughout the year in order to receive the full capacity payment to which it is entitled. (Tr. Vol. 8 at 36-38).

Witness Hinton disagreed with DEC/DEP's proposal to adopt a PAF of 1.05, explaining he disagreed with Witness Snider's reliance on the DEC/DEP CT fleet's greater than 95% availability factor. Witness Hinton argues against using the starting reliability of a CT to establish the PAF because the fixed costs of a peaking unit are just a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. Instead, Witness Hinton recommended that if a QF's availability is similar to that of the utility's baseload fleet, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. (Tr. Vol. 8 at 38-39).

Public Staff Witness Metz also testified that the PAF has been utilized in past calculations of administratively determined avoided cost rates to account for the reality that no generator can operate 100% of the hours of the year, or even 100% of the on-peak hours of the year. (Tr. Vol. 8 at 125). He explained that while he agreed that a 1.2 PAF may no longer be appropriate, he did not agree with Witness Snider that the appropriate PAF should match the reliability of a CT. He explained the Public Staff's view that while the peaker methodology uses a CT as a proxy for the pure capacity value of generation versus the energy value, it is not meant to imply that all QF capacity calculations should be based on the characteristics of a CT. (Tr. Vol. 8 at 126).

Witness Metz supported the Public Staff's proposal to establish a PAF based upon an average of broader plant availability factor for DEC, DEP, and DNCP, taking into account monthly baseload power plant performance filings, industry data and making certain assumptions based upon historical capacity factor data when current data was not available for particular units. He relied upon data and assumptions for a six year historical period 2011-2016 to derive availability factors for DEC of 88.24%, DEP of 86.91%, and DNCP of 83.85%. He then calculated a simple average of the three utilities' historical six year availability factors to arrive at an overall average of 86.33%. This was equivalent to a 1.16 PAF, which the Public Staff recommended be adopted for all three utilities' avoided capacity calculations in this proceeding. (Tr. Vol. 8 at 127-128).

NCSEA Witness Johnson testified that the issue in dispute with regards to the PAF is not the number of hours a CT is available each year. Under the peaker method, according to Witness Johnson, it is more appropriate to focus on availability data for all types of units, including baseload coal units and combined cycle units. NCSEA Witness Johnson explained that in the peaker method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units. Thus, according to Witness Johnson, the availability of other types of generating units must be considered. (Tr. Vol. 7 at 298-301).

Furthermore, Witness Johnson stated that while the calculation of the PAF can be disputed, the key point is that QFs are supposed to be treated in a non-discriminatory manner, consistent with the treatment afforded the Utilities. Achieving a reasonable degree of consistency is also important because QF rates are supposed to leave customers financially indifferent between purchases of QF power and the construction and rate basing of utility-built resources. According to Witness Johnson, retail customers are paying for all of the Utilities' generating units, including ones that only operate a few hours of the year, and units that are not available when needed during the peak hours, due to scheduled maintenance and other factors. This consistency should be viewed from the perspective of the entire life cycle of the unit, not just the first few years after it is built when reliability is at its peak and maintenance requirements are low. As units age, more maintenance may be required, more outages may occur, reliability may decline, and it may no longer be cost-effective to operate the unit 24 hours a day all year long. Thus, in order to meet the standards of ratepayer indifference and non-discrimination, according to Witness Johnson, it is necessary to remember that customers are paying the full ownership-related costs of DEC/DEP's generating units, regardless of how few hours they produce electricity during any given year, while the QFs only receive capacity payments when the QF producing electricity. (Tr. Vol. 7 at 300-02).

Witness Johnson also argued that reducing the PAF to 1.05 would cause solar generators not to receive full payment of avoided capacity costs because they are incapable of generating electricity during 95% of the on-peak hours due to the fact that many on-peak hours occur before the sun rises or after the sun sets. (Tr. Vol. 7 at 301).

SACE Witness Vitolo testified that DEC's and DEP's reasoning for reducing the PAF is incorrect for two reasons. First, he argues the resource the QF is replacing is not a CT. The peaker method assumes that the utility's fleet is in equilibrium and therefore the quantitative result is not biased by the choice of one particular technology over another. The only specific role for a combustion turbine in the peaker method is to estimate the avoided capacity cost for a new unit. There is no expectation that the QF will avoid the utility procurement of a specific generator technology or type. Second, Witness Vitolo suggests in any given hour, the QF could be displacing a peaker unit, a mid-range unit, or even a baseload unit. (Tr. Vol. 7 at 43).

Witness Vitolo stated that rather than looking at the average performance, it is appropriate to look at the worst performing company owned generator, and if that generator is considered used and useful, then a QF with a similar availability should also be considered to be operating in a reasonable manner, and therefore allowed to recover the utility's full avoided cost. Witness Vitolo pointed out that DEC's and DEP's own reporting to the Commission shows many units in its generating fleet are available considerably less than 95% of the time. DEC's and DEP's availability reporting is in line with DNCP, which has stated that 15% is a reasonable allowance for the unavailability of a baseload generating unit. (Tr. Vol. 7 at 43-44).

Witness Vitolo stated that DEC, DEP, and DNCP made an identical proposal to reduce the PAF in the 2014 Sub 140 proceeding, and that the Commission denied their arguments to revise the PAF as not sufficient at that time. Witness Vitolo recommended the Commission maintain its current policy requiring the Companies to use a 1.20 PAF for non-hydro renewable QFs because it better aligns with the expected availability of units in a utility fleet. (Tr. Vol. 7 at 44-45).

In rebuttal testimony, Witness Snider testified that while he agreed that a generic QF should not be held to a standard that requires 100% availability during peak hours to receive full avoided capacity payments, he reiterated his view that the objective of the PAF should be to ensure that a QF operating with a reliability equivalent to that of an avoided CT receives the full capacity value of the CT. He also analyzed the Public Staff's and intervenors' positions, finding that it also would be reasonable under the peaker method to view the "on-peak" reliability of baseload generation resources on the Companies' systems as equivalent to a reasonable expectation of QF availability. He explained that both metrics, when properly applied, support a PAF of 1.05 as an appropriate availability adjustment to the QF capacity rate. (Tr. Vol. 2 at 276).

Specific to the QF being required to operate at the reliability equivalent of a CT, Witness Snider explained that the avoided unit has a forced outage rate that can impact its availability during on-peak periods and thus affect system reliability and the reserve margin needed by DEC/DEP to provide reliable service. Thus, establishing a PAF that places the QF and avoided unit on the same basis in terms of their impact on system reliability is appropriate. Because the appropriate measure of reliability for a CT peaking unit is its starting reliability, and DEC/DEP's CT fleet performs at a starting reliability of above 95%, Witness Snider reiterated that it would be appropriate to establish the PAF at 1.05 as a conservative measure to ensure that QFs receive fair capacity payment compensation, but that anything greater would represent a subsidy given to smaller QFs and subject customers to unfair, unjust, and unreasonable rates that exceed the costs actually being avoided. (Tr. Vol. 2 at 277).

In responding to the Public Staff's PAF recommendation, Witness Snider explained that the Public Staff's focus on unit availability is appropriate, but their calculation has a fundamental flaw that leads to a substantial overpayment. Public Staff Witnesses Hinton and Metz testified that the annual average availability factors for certain DEC, DEP, and DNCP baseload units was about 86% from 2011-2016. Witness Snider argued that focusing on annual availability rather than just the on-peak availability incorrectly includes planned maintenance outages such as nuclear refueling outages when calculating baseload unit availability. Importantly, Witness Snider noted that QFs receive their full capacity payment based on on-peak availability only and have no obligation to produce in off-peak hours to earn a capacity payment. Witness Snider stated that planned maintenance is typically conducted during off-peak periods when demand is low. As such, to be consistent, non-biased baseload availability metrics should be analyzed from an on-peak perspective only. He testified that it obviously would not be prudent utility operating practice to schedule a nuclear unit refueling outage during peak demand periods. Similarly, in Witness Snider's view, using the entire annual availability factor for the Companies' generating fleet is not relevant to the intended purpose of the PAF which applies only to unit availability during on-peak periods. (Tr. Vol. 2 at 278-79).

In response to NCSEA Witness Johnson's testimony that utilities are not held to a 95% reliability standard, Witness Snider testified that if adjusted for off-peak refueling outages and solely examining the fleet's performance during peak summer and winter months, DEC/DEP's baseload fleet's on-peak availability factor is well in excess of 95%. Witness Snider stated that accepting the Public Staff's assertion that 86% availability is just and reasonable in setting a PAF implies that during peak periods it would be reasonable for the Companies to have 5,000 MW of generation unavailable during any given peak hour. If this Commission believes the PAF should be based on system availability as opposed to the availability of the CT, Witness Snider testified the appropriate metric is system resources' Equivalent Forced Outage Rate ("EFOR"). According to Witness Snider, EFOR represents the reliability of a unit or generation fleet during periods between maintenance intervals and is therefore a better indicator of reliability during peak demand periods. Witness Snider concluded DEC/DEP EFOR data from 2016 leads to a similar conclusion as CT starting reliability data, a PAF less than or no greater than 1.05 is appropriate to fairly pay QFs for avoided capacity during on-peak periods. (Tr. Vol. 2 at 280-82).

In response to Witness Johnson's testimony that a 1.05 PAF would require a solar QF to produce at full capacity during 95% of the on-peak hours to receive full avoided capacity costs, Witness Snider testified that if a solar QF was truly dispatchable, then the solar QF could negotiate a demand rate that allowed the QF to receive capacity payments based upon performance consistent with other dispatchable capacity resources purchased outside of PURPA. (Tr. Vol. 2 at 282-83). Witness Snider also noted that given the broad definition of on-peak hours under Option B, a typical solar QF is being compensated for almost 40% of the cost of a CT, while only providing 5% of the capacity value a CT would actually provide. (Tr. Vol. 2 at 283).

In his rebuttal testimony, DNCP Witness Petrie testified that DNCP's position is that capacity payments should not be made to proposed distribution-connected QFs in DNCP's service territory since capacity is not being avoided. For this reason, DNCP did not propose any adjustment to the PAF. However, Witness Petrie testified that if this Commission were to determine DNCP was avoiding capacity, a PAF of 1.05 is appropriate. Witness Petrie stated that since the peaker method determines avoided costs based on the installed cost of a peaking CT unit, it is logical to use the peak hours of availability for that type of resource to determine the PAF. Witness Petrie agrees with DEC/DEP Witness Snider in acknowledging the Commission's determination of the PAF in prior dockets, but circumstances have changed and utility ratepayers are now being adversely impacted. Witness Petrie testified that NCSEA Witness Johnson's reasoning for a high PAF was not compelling. Witness Petrie stated that Witness Johnson's statement that solar generators are incapable of operating during 95% of the peak hours because they occur before the sun rises and after it sets is precisely why a solar QF should not be entitled to the full avoided cost of a CT because it is not available. Witness Petrie also agrees with DEC/DEP Witness Snider that the availability factor used to determine the PAF should be based on a CT and not the generation fleet as a whole. (Tr. Vol. 5 at 267).

During the hearing, Witness Snider emphasized that both the on-peak reliability of a CT and the availability of the entire system during on-peak periods supported a 1.05 PAF. (Tr. Vol. 3 at 71, 109-11). He explained that focusing on the on-peak availability presented a more appropriate apples-to-apples comparison of utility generating unit availability and QF availability. This is because QFs are compensated for 100% of their capacity value during the approximately 25% of annual hours that are on-peak hours and the QF has the ability to be offline the other 75% of the hours in a year and still receive their full capacity payment. Witness Snider argued that the Public Staff's focus on baseload unit availability is appropriate if the metric used is analyzing on-peak availability, such as through the EFOR, to assess whether the utility's baseload units were available when needed for peak, such as on a polar vortex morning or that hundred degree summer afternoon, or just a hot day or a cold day in the winter. Witness Snider testified that focusing on the on-peak availability is absolutely critical to establishing an equivalent apples-to-apples basis in the real world when looking at utility-generator availability and then comparing it to how the QF is being compensated for capacity. (Tr. Vol. 4 at 124-125). He also explained in response to questions from Commissioner Brown-Bland that he was unaware of other jurisdictions that paid a pure capacity multiplier like the PAF, and that reevaluating the PAF was appropriate given the unprecedented surge in solar QFs. Witness Snider also emphasized DEC/DEP's support for the on-peak EFOR metric to develop an apples-to-apples comparison is different than the arguments used to support the 1.05 PAF in Sub 140. (Tr. Vol. 5 at 114-15).

On cross examination by DEC/DEP, Witness Metz explained that the Public Staff had made a significant change in this proceeding from prior proceedings in evaluating the PAF by focusing on unit availability factor versus capacity factor. (Tr. Vol. 8 at 186). He also agreed that solar QFs are being compensated for capacity based upon their availability to deliver during on-peak periods. (Tr. Vol. 8 at 186). Finally, Witness Hinton agreed that the focus of QF capacity value is based upon the QF's ability to deliver capacity on-peak in order to offset other capacity needs, and that it is appropriate to establish a PAF multiplier based upon analysis of the utility's generating units' on-peak availability. (Tr. Vol. 8 at 186).

<u>Discussion and Conclusion</u>

In the *Sub 140 Phase I Order*, the Commission upheld its prior determination in the 2004 avoided cost proceeding that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed costs of any avoided generating unit under the peaker method. *Sub 140 Phase I Order* at 56. However, the Commission did not expressly find this CT availability factor metric to be irrelevant. Instead, at that time, the Commission elected to maintain the long-established 1.2 PAF, finding there had been widespread QF development under the existing framework without adverse impacts to utility ratepayers.

In this proceeding, both the Public Staff and DEC/DEP agree that a PAF multiplier should continue to be offered, while both of these parties have also evolved the manner in which they have analyzed the appropriate metrics to support a PAF. The Public Staff has testified that they have made a significant change to prior practice by relying upon utility baseload and intermediate generating unit availability factor data versus capacity factor data as in past proceedings. DEC/DEP Witness Snider has reiterated his analytical support for a 1.05 PAF in two ways. First, he presented the peak availability of DEC/DEP's CT fleet. Then, in rebuttal to the Public Staff, Witness Snider also supported the on-peak EFOR of DEC/DEP's respective baseload and intermediate fleets to show that a 1.05 PAF provides a QF the reasonable equivalent opportunity to have outages during the peak period during which QFs recover their full capacity costs.

This Commission finds and concludes that a 1.05 PAF is more reasonable and appropriate in this proceeding for a number of reasons. First, the Commission finds that both the availability of the avoided CT as well the broader fleet availability provide support for a 1.05 PAF. Regarding CT availability, the fact that the CT is a proxy for any avoided generating unit under the peaker method does not mean that this metric should be discarded as irrelevant, and so the Commission gives it some weight. The evidence in the record also shows that DEC/DEP, the Public Staff, and NCSEA Witness Johnson agree that analyzing broader fleet unit availability is appropriate, but that the Public Staff and DEC/DEP disagree on whether annual or on-peak availability is the appropriate metric. Based upon the extensive evidence in the record, the Commission agrees with DEC/DEP that analyzing on-peak availability provides a more appropriate and "apples-to-apples" comparison for establishing a PAF to allow a QF a reasonable opportunity to recover its avoided capacity value. The rationale for valuing capacity during "on-peak" hours – and for paying QFs for the capacity value they deliver during peak periods – is to recognize the utility's greater need for capacity and generator availability to deliver energy during peak periods in order to ensure reliability when system load is greater. As DEC/DEP Witness Snider explains, utilities' plan system reserve margins to meet on-peak capacity needs and logically also plan for generator maintenance outages during off-peak periods when loss of load risk is very low. Disregarding the fact that the utilities build or purchase capacity primarily to meet peak needs versus annual needs and, in relation, plan for outages during non-peak periods, would result in a significant increase in utility's reserve margin requirements and a commensurate significant increase in costs to consumers to build or buy greater amounts of capacity in order to provide reliable service. (Tr. Vol. 3 at 280). Witness Snider explains that this higher reserve margin and increase in costs would be the net real world result of the Public Staff's annual 86% availability factor equivalency argument. It is also undisputed that QFs do not have to produce a single MWh in off-peak hours during the year to receive their full capacity payment. Accordingly, establishing a capacity performance multiplier that takes into account the utility's generating unit availability during the non-peak hours where the QF does not have to deliver power under the current rate design in order to receive its full capacity payment does not seem reasonable or appropriate. Similar to the utility, the QF can plan for outages during these non-peak periods and still be viewed as 100% available and receive its full capacity value.

The Commission also is sensitive to the potential for adverse ratepayer impacts of continuing to pay an unreasonably high PAF capacity payment multiplier for largely nondependable and non-dispatchable utility-scale QF solar capacity in light of current economic and regulatory circumstances discussed earlier in this Order. While DEC/DEP and the Public Staff recognize that the avoided cost rates being evaluated in this proceeding are "generic" avoided cost rates available to all QF technologies, the reality over the past few years is that the PAF multiplier has almost exclusivity been applied to incent development of solar QF generators in North Carolina. (Tr. Vol. 3 at 282; Tr. Vol. 8 at 187). For example, Witness Bowman testified that of the 3,323 MW of proposed QF generation under development in DEP that is not yet under contract, only 5.8 MW was non-solar. Based upon the recent significant levels of solar QF development under the standard offer, and the potential that significant solar QF development will continue under the new standard offer rates approved in this Order, the Commission no long finds that adverse impacts to utility ratepayers is being avoided under the prior PAF multiplier approved by the Commission. The Commission also notes that DEC/DEP's testimony was uncontroverted that North Carolina is the only jurisdiction that applies a pure capacity multiplier similar to a PAF, which seemingly has contributed to the significant solar QF growth in North Carolina versus other jurisdictions. (Tr. Vol. 3 at 225-226; Tr. Vol. 5 at 114).

Based on the foregoing, the Commission finds and concludes that a PAF of 1.05 is appropriate and should be adopted by DEP and DEC for purpose of calculating their Schedule PP avoided capacity rate design.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-17

The evidence supporting these findings of fact is found in DEC/DEP's Joint Initial Statement, the testimony and exhibits of DEC/DEP Witnesses Bowman and

Freeman, the rebuttal testimony of DNCP Witness Gaskill, the testimony of NCSEA Witness Harkrader, and the testimony of Public Staff Witnesses Lucas and Hinton.

DEP/DEC Witness Bowman testified that the current standard to establish a LEO, as approved in the 2014 Sub 140 proceeding requires the QF developer to take the following actions: (1) self-certify with the FERC as a QF; (2) obtain a CPCN from the Commission to construct the generator; and (3) indicate its intent to make a commitment to sell the facility's output under PURPA via the use of an approved Notice of Commitment Form. However, Witness Bowman also testified that the current process is increasingly imposing unjust and unreasonable purchase obligations on the Companies' customers without actually obligating the QF to sell to the utility. (Tr. Vol. 3 at 361-62).

DEP/DEC Witness Freeman, who manages both power contracting and distribution interconnection activities for DEC and DEP, also testified to his recent experience that the commitment to sell purportedly being made by QFs who submit the Notice of Commitment Form is not meaningful or binding on the QF. Witness Freeman explained that the commitment to sell power under the current LEO standard is being made early in the development process when the QF (i) has no concrete information on the feasibility, cost, or timing of interconnection; (ii) is not ready, willing, and able to sell power; and (iii) has not begun PPA negotiations with the utility. Witness Freeman explained that this is not consistent with PURPA's intent that a QF must make a legally enforceable commitment to sell – either through executing a PPA or under a non-contractual LEO where the utility refuses to enter into a contract – in order to obligate the utility and its customers to purchase the QF's output. (Tr. Vol. 2 at 436-37).

Witness Freeman described some of the unique provisions of the North Carolina

Interconnection Procedures (NCIP) approved by the Commission in May 2015 that impact whether a QF can make a reasonably informed commitment to sell early in the interconnection and QF development process. He highlighted changes to the study process including elimination of the initial feasibility study so that the System Impact Study is now the first study completed, during which the feasibility, grid impacts, and preliminary ballpark cost to interconnect the generator are analyzed. He noted that as interconnected solar capacity has increased on DEP's rural distribution system, certain proposed points of interconnection cither may not be feasible to interconnect additional solar without adversely impacting power quality and reliability or the proposed generator must be significantly modified (i.e., a reduction in nameplate generator capacity) during the study process to make interconnection to the local distribution system feasible. Increasingly, significant system upgrade costs are likely to be required, as the average upgrade cost for utility-scale generators exceeded $400,000 in 2016. (Tr. Vol. 2 at 438, 443).

Witness Freeman also explained the interdependency-driven interconnection processing under NCIP Section 1.8, which prioritizes studying generators whose proposed points of interconnection are not impacted by upgrades required to interconnect lower-queued generators. Currently, there are over 150 "On Hold" interconnection requests in DEC's and DEP's North Carolina interconnection queues and 33 different substations where more proposed generators (A, B, C, and D) have submitted an interconnection request for study than can even be accommodated by the substation size, transmission, and/or distribution systems. Witness Freeman also identified how the interim interconnection agreement and "dwell period" between the System Impact Study and Facilities Study are designed to allow QFs to continue with project development work, but emphasized that QFs are not required to make any binding commitments to proceed with the generator during the study phase of the interconnection process. (Tr. Vol. 2 at 439-441).

Witness Freeman emphasized that the first meaningful commitment by a QF developer under the Section 4 Full Study interconnection process occurs where the interconnection customer executes the interconnection agreement (IA) and financially commits to construction of system upgrades so projects later in the study queue (and the utility processing the studies) can rely on the required system upgrades being constructed. He explained that DEC and DEP have also treated the 60 calendar day period provided in the NCIP for payment of upgrades as an informal due diligence period where the interconnection customer may terminate the IA without liability if the QF elects not to pay for upgrades under the IA and to terminate the project. (Tr. Vol. 2 at 441-42).

Witness Freeman also testified to his recent experience that two to four years could pass between a Sub 140 "LEO date" established early in the QF interconnection and development process and the point in time that a QF begins delivering power to customers. This extended period heightens the risk and likelihood that the LEO-committed avoided cost rates no longer align with DEC/DEP's then-existing avoided costs, effectively assigning the risk of stale and inaccurate avoided costs to DEC/DEP's customers. (Tr. Vol. 2 at 444).

Witness Freeman explained that DEC and DEP initially proposed modifications to the current Notice of Commitment Form in DEC's and DEP's Joint Initial Statement Exhibit 5, which was intended to modify the current Notice of Commitment Form to require a utility-scale QF developer proceeding through the Section 4 full study process to make some indicia of commitment by executing and returning a Facilities Study Agreement after the dwell period, thereby committing the project to a detailed engineering and construction Facilities Study. (Tr. Vol. 2 at 449). However, Witness Freeman then explained that DEC and DEP modified their recommendation and now support the Commission transitioning the current LEO standard to formalized contracting procedures between larger QFs and the utilities, which will more appropriately align the establishment of a legally enforceable commitment to sell with the date upon which a QF actually agrees in a PPA to commit itself and becomes obligated to deliver power over a specified term. Witness Freeman explained that similar contracting procedures have been adopted in other jurisdictions with significant PURPA activity, including Oregon and Idaho, where a LEO commitment to sell is tied to the QF's commitment to deliver power under a PPA. For example, Witness Freeman explained that a LEO is deemed to arise in Oregon where a QF signs a final draft of an executable PPA that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date. He explained that adopting similar contracting procedures could resolve the Companies' concerns about the growing harm to customers of stale avoided cost rates, while also providing QFs certainty as to the process for negotiating a definitive PPA. This proposal would also better ensure that the QF developer and not the Companies' customers is taking on the risk of the QF's non-performance at the time the QF's "commitment to sell" is made. Witness Freeman emphasized that customers should be protected from the risk of the QF's potential non-performance by including reasonable and appropriate liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform) in negotiated PPAs for large QFs. (Tr. Vol. 2 at 450-52). If the QF and the utility cannot agree to a PPA, the QF could also file a complaint or petition for arbitration with the Commission. (Tr. Vol. 2 at 454).

Witness Freeman also explained the expedited Fast Track study process for smaller generators, (Tr. Vol. 2 at 444), and testified that DEC and DEP supported a streamlined LEO form for small QFs 1 MW or less that are eligible for the standardized avoided cost rates and terms and conditions. The streamlined form would consist of: (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3 Interconnection Request, which the Company deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QF's output to DEC or DEP under then-approved standard avoided cost rates. (Tr. Vol. 2 at 452).

Public Staff Witness Lucas testified that the Public Staff agreed with Witness Freeman's LEO standard proposal for small QFs 1 MW or less that are eligible for the utilities' standard offer. (Tr. Vol. 8 at 95). However, for larger QFs not eligible for the standard offer, the Public Staff did not agree with DEC's and DEP's modified proposal to tie the establishment of a LEO to execution of the PPA. Instead, the Public Staff recommended the Commission maintain the current LEO standard with two additional requirements: (1) the QF must be a Project A or Project B in the interconnection queue, as described in Section 1.8 of the NCIP; and (2) the LEO would not be established until the earlier of the QF's receipt of the utility's System Impact Study or 105 days after the

QF submits a complete interconnection request to the Company. Witness Lucas explained that projects designated as Project C status or below should be ineligible to establish a LEO because only projects designated as A or B are evaluated in the interconnection study process, and until the project begins progressing through the study process, the project owner has little or no information regarding whether it is technically or economically feasible to interconnect at its requested point of interconnection. Witness Lucas also explained that under the timeframes in the NCIP, a utility should complete the System Impact Study for a Project A or Project B within 105 days of interconnection request submission, assuming all timeframes in the NCIP are followed. Upon receiving the System Impact Study results, a QF owner should have information on the feasibility, costs, and time required for its proposed interconnection, and therefore be in a better position to evaluate the viability of the project and commit to building the facility than at the beginning of the interconnection process. (Tr. Vol. 8 at 96-97).

Witness Lucas testified that data produced by DEC and DEP in discovery suggested that the current average time required to complete a System Impact Study exceeded 105 days, especially for larger QFs 5 MW or 20 MW in size, and further suggested that tying the LEO to the NCIP timeframes provides an incentive to utilities to move projects through the interconnection process in a more timely fashion, which would help ensure that the utility's payments to a QF reflect current avoided costs. (Tr. Vol. 8 at 98, 101). Witness Lucas also suggested that he believed the Public Staff's proposal was more consistent with the FERC's recent *FLS Energy* decision, where FERC held that an administratively-established LEO standard that required a QF to have executed and returned an IA to the utility allowed the utility to control whether and when a LEO exists and was inconsistent with PURPA.[18] (Tr. Vol. 8 at 99).

Witness Lucas also identified that the Public Staff agrees with DEC's and DEP's concerns about the current Notice of Commitment Form resulting in "stale" rates that are no longer representative of the utility's current avoided costs at the time the QF begins delivering power, and suggested that other proposed PURPA policy changes recommended by Public Staff Witnesses Hinton and Metz would help address part of this concern. However, Witness Lucas also testified that in the event avoided cost rates begin to increase, a QF may instead wish to delay its establishment of a LEO, or even allow a previously executed Notice of Commitment to expire in order to establish a new LEO at the higher rates. In this case, a change in the LEO date could result in customers losing the benefit of the lower rates to which the QF had previously committed, and even potentially allow gaming of rates by a QF at customers' expense. The Public Staff proposes that the LEO form be modified to include a provision that limits a QF that withdraws its Notice of Commitment from being able to establish a new LEO for two years from the date of the withdrawal, and instead limit the QF to the utility's "as available" energy rates during that time. (Tr. Vol. 8 at 101-02).

Public Staff Witness Hinton testified that the Public Staff generally agrees with Witness Freeman's testimony regarding the establishment of reasonable contracting procedures that improve the transparency and efficiency of the negotiated PPA process. Witness Hinton recommended DEC and DEP provide additional details regarding its proposal, and specifically highlighted his support for certain standards including providing for specific timeframes for both parties to provide information and responses; providing for a standardized contract form with clear delineation of any specific changes

[18] *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at 23 (2016) ("FLS Order").

or points of negotiation clearly identified; providing for the utility to deliver indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and be able to seek financing; and providing an opportunity for either party to seek informal resolution of disputes or to petition for arbitration with the Commission. (Tr. Vol. 8 at 62-63).

NCSEA Witness Harkrader testified that the LEO standard should be revised to allow the QF to provide a Notice of Commitment Form to the purchasing utility after 105 days have lapsed from the interconnecting utility's receipt of the QF's interconnection request, which is the time established under the NCIP for the utility to complete the System Impact Study process. Witness Harkrader expressed concern that DEC/DEP's initial proposal requiring a QF to progress through System Impact Study and commit to proceed to a detailed Facilities Study would give control over the timing of the establishment of the LEO to the utility, which, although not a lawyer, she asserted is inconsistent with PURPA. Witness Harkrader also argued that QFs make numerous commitments in the early stages of the development process, including finding a suitable site for the facility, negotiating site control with the landowner, completing environmental surveying and permitting, securing of land use approvals, securing of regulatory approvals, and the initiation of the interconnection study process. (Tr. Vol. 7 at 382-85). Witness Harkrader also responded to DEC's and DEP's concerns about stale rates by stating that current delays in the interconnection study process are typically caused by long utility study timelines and are not caused by the QF. (Tr. Vol. 7 at 385-86).

In rebuttal testimony, Witness Freeman noted that the Public Staff does not specifically respond to or disagree with DEC's and DEP's core concerns that the purpose of a LEO under PURPA is to allow a QF to make a legally enforceable commitment to sell power – either through executing a PPA or under a non-contractual LEO should the utility refuse to enter into a contract – in order to obligate the utility and its customers to purchase the QF's output. Witness Freeman testified that the Public Staff's proposed LEO standard for larger QFs will not actually require QFs to make a meaningful or binding commitment (i.e., take on the risk of non-delivery of power) in order to obligate the Companies' customers to buy the QF's power under PURPA. Allowing QFs to administratively establish a LEO 105 days after submitting an interconnection request or becoming a Project A or Project B essentially continues the current policy of providing QFs the right or option to sell at avoided cost, but creates no obligation that the QF will actually build the generator or deliver power to the Companies. (Tr. Vol. 2 at 461-62). He also noted that the QFs at issue in FERC's *FLS Order* had already executed PPAs at the time they alleged LEOs were established, which he viewed as consistent with DEC/DEP's position and proposed contracting procedures. (Tr. Vol. 2 at 466-67). Witness Freeman also rebutted NCSEA Witness Harkrader's testimony regarding developers' commitments of time and financial resources during the early stages of QF development process by explaining that these are not the commitments contemplated by FERC's regulation and that a LEO should arise under PURPA only where the QF commits itself to deliver power to the utility over a specified term. (Tr. Vol. 2 at 463).

Witness Freeman also responded to NCSEA's and the Public Staff's testimony that current delays in the interconnection study process are within the utility's control. He emphasized that the level of proposed utility-scale solar on the DEP distribution system is unprecedented across the country, and that approximately 785 new requests to interconnect a combined 6,700 MW of utility-scale solar have been submitted to DEC and DEP since January 1, 2014. Of these projects, 28% have either withdrawn from the interconnection process or canceled their project, suggesting the speculative nature of the early QF development process and, specifically, of establishing a LEO proximate to submitting the interconnection request. However, Witness Freeman agreed that DEC and DEP must ultimately manage and control the interconnection study process to ensure all requests to interconnect new generators to the distribution and transmission systems are studied in a non-discriminatory manner that assures long-term system safety, reliability of service, and power quality for all customers. (Tr. Vol. 2 at 465).

Witness Freeman's rebuttal testimony also presented a "Notice of Intent to Negotiate a PPA" form in DEC/DEP Freeman Rebuttal Exhibit 2. Section four of this form presented contracting procedures for large QFs negotiating a PPA. Witness Freeman testified that the proposed contracting procedures are commercially reasonable and will improve the transparency and efficiency of the negotiated PPA process by establishing clear milestones and a process for good faith negotiations between the QF and utility. He also explained that the contracting procedures modify the process for a large QF to make a legally enforceable commitment to sell by focusing on the QF's commitment to enter into a PPA as establishing its obligation to deliver energy or capacity over a specified term. Under the contracting procedures, the decision to make such a commitment is completely within the QF's control, and only where the QF and the utility cannot agree on the terms and conditions of the PPA would the Commission need to get involved to determine whether a non-contractual LEO has been established. Prior to the QF making a commitment to sell by entering into a PPA, the utility will provide non-binding indicative avoided cost pricing that may be used by the QF developer to make determinations regarding project planning, financing, and feasibility of the proposed QF project. This approach mitigates the risk of stale avoided cost rates as the QF will be provided indicative pricing information needed to evaluate developing the QF, but will not “lock in” avoided cost rates until it actually makes a commitment to deliver power to the utility over a specified term by executing a PPA. Witness Freeman also suggested that the Companies’ PPA would continue to include a 60 calendar day “post-execution due diligence period,” providing the QF reasonable additional time to ensure it is prepared to make a legally enforceable commitment to sell power over the term specified in the PPA. (Tr. Vol. 2 at 470-71).

Exhibit 1 to Witness Freeman’s rebuttal testimony presented a revised Notice of Commitment Form for small QFs 1 MW or less that are eligible for the utilities’ standard offers. He asserted that this proposed streamlined form was reasonable and appropriate for these smaller QFs because the standard Schedule PP rates, terms, and conditions are fixed for a two-year period. (Tr. Vol. 2 at 468). The modified standard offer Notice of Commitment Form was consistent with the proposal presented in his direct testimony as supported by Public Staff Witness Lucas. (DEC/DEP Freeman Rebuttal Exhibit 1; Tr. Vol. 2 at 469).

Witness Freeman requested the Commission direct DEC/DEP to take input from the Public Staff, DNCP, and other interested parties on the large QF Notice of Intent to Negotiate Form and contracting procedures presented in Freeman Rebuttal Exhibit 2 and to submit any refinements to the proposed contracting procedures as a post-hearing filing.

(Tr. Vol. 2 at 469).

DNCP Witness Gaskill testified in his rebuttal testimony that he supported DEC/DEP's proposed LEO changes and shared many of the concerns presented by DEC/DEP Witnesses Bowman and Freeman. He testified to DNCP's experience that the current process allows a QF to establish a LEO before it is in a position to truly commit to develop the project and deliver power in a timely manner. (Tr. Vol. 5 at 200). Witness Gaskill explained that continuing a LEO policy that effectively allows a QF to establish a put option price, but has not obligated the QF to actually deliver power to the utility has two significant implications, both of which unjustly harm customers. First, it impairs adequate utility system planning because DNCP does not know how much QF power will ultimately be constructed and delivered. Second, the current process has created a situation where the LEO, and thus avoided cost prices, are significantly outdated by the time the QF actually completes construction and begins delivering output. Witness Gaskill also testified that DNCP would work with DEC and DEP, the Public Staff, and other stakeholders on any modifications to the current Notice of Commitment Form and DEC/DEP's proposed contracting procedures. (Tr. Vol. 5 at 201; Tr. Vol. 6 at 79-80).

At the hearing, Witness Freeman explained that the contracting procedures presented in his Rebuttal Exhibit 2 do not require a QF to complete the System Impact Study phase of the interconnection process to begin the negotiation process, and that a QF only has to be a Project A or Project B to commence negotiations similar to the Public Staff's LEO proposal. (Tr. Vol. 5 at 68).

During examination by Commissioner Brown-Bland, Witness Freeman testified that DEC's and DEP's proposal under the proposed contracting procedures to establish a

LEO was completely in control of the QF. (Tr. Vol. 5 at 68, 104). He further reiterated that the interconnection process in North Carolina is a "living lab" in light of the unprecedented development of 5 MW distribution connected utility scale solar projects, and that DEC's and DEP's initial LEO proposal recognized that a firm commitment to sell could not be made until the QF has a clear idea of its costs to develop the project, including interconnection costs. (Tr. Vol. 5 at 107-08). Recognizing that roughly 30 percent of QFs withdraw from the interconnection process, Witness Freeman explained that it does not make sense for QFs to establish a LEO early in the development process when they are not making a meaningful commitment to sell. Therefore, DEC's and DEP's contracting procedures place the responsibility on the developer to decide when to truly make a binding commitment to deliver energy to the utility. (Tr. Vol. 5 at 107-08). Witness Freeman also explained that if a QF establishes a LEO and then fails to deliver power, then this uncertainty, especially in the aggregate of 1,000 MW or 2,000 MW, challenges the utility's system planning and fuel procurement optimization, which can harm the utility's customers. (Tr. Vol. 5 at 110-11).

During examination by Commissioner Bailey, Witness Freeman explained that the liquidated damages included in DEC/DEP's negotiated PPA when a QF makes an enforceable commitment to sell equates to roughly one year's worth of capacity costs projected to be paid under the PPA. (Tr. Vol. 5 at 117). Witness Freeman also explained that liquidated damages would only apply to large QFs above 1 MW and were not included in the small QF standard offer contracts. (Tr. Vol. 5 at 69).

During examination by DEC/DEP, Public Staff Witness Lucas conceded that under the Public Staff's LEO proposal, the utility is committed to buy from the QF at the time of the LEO, but the QF is not actually committed to deliver energy until it executes a PPA. Prior to that time, the QF is purportedly making a commitment to sell power without actually committing to build the generator at all. (Tr. Vol. 8 at 206-07). Witness Lucas further testified that if a QF wants to make a meaningful commitment to deliver power to the utility, the QF would do so by executing a PPA. (Tr. Vol. 8 at 208).

During examination by DEC/DEP, NCSEA Witness Harkrader similarly confirmed that QF projects are currently submitting Notice of Commitment Forms and establishing LEOs under the process approved in Sub 140 early in the QF development process before entering into material contracts to build the generators, before procuring panels or other equipment, and before obtaining financing to complete construction of the project. (Tr. Vol. 7 at 422-24). Witness Harkrader further explained that QFs prefer not to take on the contractual risk of entering into a PPA to deliver power on a specified date until the interconnection study process is complete and the QF is advised by the utility regarding the timing for completion of interconnection construction under the IA. (Tr. Vol. 7 at 428).

Discussion and Conclusions

It is uncontroverted in this proceeding that all QFs have the right under the Commission's implementation of FERC's PURPA regulations to sell power to utilities pursuant to a legally enforceable obligation. Specifically, 18 C.F.R. § 292.304(d) provides that QFs shall have the option to either sell energy on an as-available basis or

> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.

18 C.F.R. § 292.304(d)(2). The meaning of the LEO concept was addressed in Order No. 69, where the FERC explained that the "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility." *Order No. 69*, 45 Fed. Reg. at 12,224.

The issue presented by DEC/DEP's proposed modifications to the current LEO standard for small QFs and request for approval of detailed contracting procedures focuses on what actions QFs in North Carolina must take or "incur" to create a "legally enforceable obligation for the delivery of energy or capacity over a specified term," which then obligates the utility and its ratepayers to purchase power from the QF. This determination is squarely within the Commission's authority to either establish a process and/or standards to be applied for QFs to establish a LEO or to evaluate such issues on a case-by-case basis. *See New PURPA Section 210(m) Regulations, Order No. 688-A*, 119 FERC ¶ 61,305 at ¶¶ 136, 139 (2007); *see also Power Res. Group, Inc. v. PUC*, 422 F.3d 231, 239 (5th Cir. Tex. 2005) (". . . defining the parameters for creating a LEO is left to the states and their regulatory agencies").

<u>Streamlined LEO Form for Small QFs Eligible for Standard Offer</u>

Witness Freeman testified that a streamlined LEO form is reasonable and appropriate because the Utilities' standard offer rates, terms, and conditions are fixed for a two-year period. The streamlined form presented in DEC/DEP Freeman Rebuttal Exhibit 1 reflects that the standard offer, as proposed by the respective Utilities and approved by the Commission in this Order, applies to QF generators 1 MW or less, and provides for an administratively-established LEO where the QF completes the following steps in the development process: (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3 Interconnection Request, which the Company deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QF's output to DEC or DEP under then-approved standard avoided cost rates. The Public Staff and DNCP generally supported this streamlined Notice of Commitment Form in concept, and no parties opposed or requested changes to the form presented in Witness Freeman's rebuttal testimony during the evidentiary hearing.

The Commission agrees with DEC/DEP that maintaining an administratively efficient LEO standard and procedure is reasonable and appropriate for smaller QFs that are eligible for the Utilities' respective standard offers. Specifically, a brightline LEO standard is appropriate for QFs eligible for the standard offer because the LEO date for these small QFs is only determinative of the vintage of biennially-established standard offer rates and terms and conditions for which a QF qualifies. The Commission's approval of a streamlined process for these small QFs to notify the utility of its intent (even if it is not necessarily a binding commitment) to sell is also consistent with the streamlined Report of Proposed Construction and expedited interconnection study procedures available to smaller QFs 1 MW or less.

The Commission also finds the Public Staff's proposal to limit a QF that withdraws its Notice of Commitment Form from being able to establish a new LEO for two years from the date of the withdrawal to be reasonable and appropriate. During this period, the QF would continue to be eligible for to the utility's "as available" energy rates.

The Commission finds that the streamlined Notice of Commitment Form submitted as DEC/DEP Freeman Rebuttal Exhibit 1 should be approved subject to modification to incorporate the Public Staff's recommendation, as discussed further below.

Proposed Contracting Procedures and LEO Standard for Large QFs

Prior to the 2014 Sub 140 biennial avoided cost proceeding, the Commission has generally applied a two-prong test for establishing a LEO, which required that a QF generator must: (1) have made a commitment to sell the facility's output to a utility pursuant to PURPA; and (2) have received a CPCN for the construction of the facility. *See, e.g.*, *Order on Pending Motions* at 2-3, Docket No. E-100, Sub 74 (Feb. 13, 1995) (requiring a QF to have obtained a CPCN under North Carolina law and to be "ready, willing, and able to sign a contract" to establish a non-contractual LEO); *Order on Arbitration* at 8-9, Docket No. E-2, Sub 966 (Jan. 26, 2011) (where QF already has CPCN, "when [the QF] committed itself to sell its output over a specified term" is determinative of when the LEO arose). In Phase 1 of the Sub 140 proceeding, DNCP raised concerns that additional guidance was needed to implement the "commitment to sell" prong of the LEO standard in order to avoid disputes between utilities and QF developers as to the date when the LEO arose. *See Sub 140 Phase II Order*, at 48. Accordingly, DNCP advocated for adoption of a form through which QFs could clearly show their intent to sell their output to a utility, thereby setting the date that a LEO is established. *Id.* at 48. Subsequently, in Phase II of the Sub 140 proceeding, DNCP proposed a form for purposes of establishing a LEO date and, after receiving input from DEC/DEP, the Public Staff and other parties, the Commission approved the currently-operative Notice of Commitment Form as well as the current LEO standard. The current mandatory brightline LEO standard requires a QF developer to (1) have self-certified with the FERC as a QF; (2) have made a commitment to sell the facility's output to a utility pursuant to PURPA via the use of the approved Notice of Commitment Form; and (3) have received a CPCN for the construction of the facility. *Id*, at 51-52. The *Sub 140 Phase II Order* also held that any changes to the approved LEO Notice of Commitment Form should be submitted to the Commission for approval. *Id*., at 52.

In support of modifying the current process for establishing a LEO in this proceeding, DEC/DEP Witnesses Bowman and Freeman describe their recent experience since the Notice of Commitment Form was approved in 2015 that significantly larger QFs up to 80 MW are now establishing LEOs early in the development process when the QF (i) has no concrete information on the feasibility, cost, or timing of interconnection; (ii) is not ready, willing, and able to sell power; and (iii) has not begun PPA negotiations with the utility. Based upon this experience, DEC's and DEP's primary concern is that these larger QFs (i.e., QFs not eligible for the utilities' respective Schedule PP standard offers) are establishing LEOs at the time a CPCN is granted without making any meaningful or binding commitment to deliver power over a future term. Accordingly, DEC/DEP explain these QFs are not accepting any risk or obligation to complete development of the QF generator or to deliver power as of a future date when the "commitment to sell" is purportedly made. Witness Freeman explained that approximately 30 percent of generators that initiate the interconnection process ultimately withdraw, and that the growing costs and complexity of interconnecting additional utility-scale solar generators to the DEP and DEC distribution and transmission systems makes an alleged commitment to sell made early in the development process not meaningful to the utility nor binding on the QF. DEC/DEP Witness Freeman and DNCP Witness Gaskill also emphasized how the current LEO standard is effectively creating a "put option" that provides QFs the right to sell at the Utilities' then-existing avoided costs two to four years ahead of when the QF may begin delivering power, resulting in increasingly stale and inaccurate avoided cost rates if and when a QF begins delivering power under a future negotiated PPA.

In support of its proposed contracting procedures, DEC/DEP advocate for evolving the current brightline LEO standard toward a process primarily focused on establishing a legally enforceable commitment to sell through a PPA that would bind the QF to deliver power over a specified term and bind the utility and customers to purchase that power as of the QF's committed delivery date. DEC/DEP further assert that the Notice of Intent to Negotiate Form provides a reasonable and transparent procedure for larger QFs to control the timing of making a legally enforceable commitment to sell by negotiating a PPA with the utility. They also emphasize that the proposed modified process assures the QF developer, and not the Companies' customers, takes on the risk of the QF's non-performance at the time the QF's "commitment to sell" is made by including reasonable and appropriate liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform) in the negotiated PPA agreed to between the QF and utility. DEC/DEP also identified other jurisdictions with significant PURPA activity that have established similar contracting procedures as the main process for a QF to establish a LEO and commitment to sell power, such that a Commission-established non-contractual LEO need only arises where the utility refuses to enter into a negotiated contract or the parties otherwise cannot agree on PPA terms and conditions. No party presented evidence that the LEO standards proposed by NCSEA or the Public Staff were consistent with the PURPA implementation regime in any other States.

Based upon the foregoing, the Commission finds that it is reasonable and appropriate to modify the current process by which large QFs above 1 MW commit themselves to deliver energy and capacity to the utilities in North Carolina under PURPA by adopting the Notice of Intent to Negotiate Form and proposed contracting procedures substantially in the form presented in DEC/DEP Freeman Rebuttal Exhibit 2. As further addressed below, the Commission's approval of this contracting procedure form and process shall be subject to a 30 calendar day period for the Public Staff, DNCP, and other interested parties to provide input into the proposed contracting procedures.

Under this contracting procedures process, QFs can initiate PPA negotiations upon obtaining a CPCN, and becoming a Project A or Project B in the interconnection study process, after which time DEC/DEP will provide QFs with non-binding indicative avoided cost pricing that may be used by the QF developer to make determinations regarding project planning, financing, and feasibility of the proposed QF project. At this point in the process, the QF is not obligated to build the generator and deliver power over a specified term and the utility is not obligated to purchase power from the QF. Section four of the form then provides a clear step-by-step process for QFs to proceed from initial notification of intent to sell through the negotiation process of a definitive and mutually binding PPA. Until the QF makes a legally enforceable commitment to deliver power through a PPA, the contracting procedures provide that the utility shall update its indicative avoided cost every 60 calendar days until the QF's reasonably proposed in-service date is equal to or less than 180 days in the future. This assures that the utility's forecasted avoided costs will be as accurate as possible up to the time the QF makes a binding commitment to deliver power. Should a QF elect to enter into a PPA at the time they obtain a CPCN and commence the interconnection study process, the contracting procedures provide the QF the right to make such a legally enforceable commitment to sell power; however, if this decision is made hastily by the QF in attempting to get a project on-line prior to completing the interconnection study process, customers are protected through liquidated and/or termination damages pursuant to the terms of the PPA. DEC/DEP highlight that its standardized negotiated PPA terms and conditions also allow QFs a 60 calendar day post-execution due diligence period, which provides the QF reasonable additional time to ensure it is prepared to make a legally enforceable commitment to sell power as of the delivery date and over the term specified in the PPA.

DEC/DEP and DNCP have presented uncontroverted testimony in this proceeding that the current brightline LEO standard approved in the Sub 140 proceeding is allowing large QFs to establish a legally enforceable obligation that is not binding on the QF. It is clear from the evidence that large QFs up to 80 MW are establishing LEOs under the current standard as of the time a CPCN is issued, which occurs very early in the QF's interconnection study process and likely multiple years before the QF will be constructed and capable of delivering power. For the approximately 150 "on hold" utility scale solar projects in DEC's and DEP's interconnection queues, this LEO commitment is also potentially being made well before the interconnection study process even commences pursuant to Section 1.8 of the NCIP. It was also clear from the Public Staff's testimony during the hearing that QFs are not necessarily committing to build the generator at all as of the time they are asserting a legally enforceable commitment to sell power. Further, NCSEA's testimony suggests that some QFs are making a speculative commitment to sell power prior to entering into the material contracts that are required to finance the project or to procure panels and other equipment needed to construct the proposed generator. The Commission finds the current situation, while well-intentioned by the parties and the Commission in Sub 140 Phase II, to be irreconcilable with PURPA's requirement that QFs must make a legally enforceable commitment to sell power to then obligate the utility and customers to purchase its output; such a non-binding and illusory commitment to sell is simply not consistent with the LEO concept, as established by FERC's regulations.

The Commission finds that the meaning of a "legally enforceable obligation" under PUPRA's regulations is meant to establish a mutually-binding arrangement primarily through a contract or, should a utility attempt to circumvent its purchase obligations by "refusing to enter into a contract with a [QF]," then through a non-contractual legally enforceable obligation. *Order No. 69*, 45 Fed. Reg. at 12,224. The FERC affirmed this view in its 2009 *J.D. Wind* declaratory order, explaining that "a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, *but binding*, legally enforceable obligations." *J.D. Wind 1, LLC*, 129 F.E.R.C. ¶ 61,148 at 25 (2009) (emphasis added). While the FERC has provided limited additional guidance as to the affirmative requirements to establish such a non-contractual, but binding LEO, the FERC has provided some guidance regarding its views of when a state's LEO standard may be inconsistent with PURPA.[19] For example, requiring a QF to obtain a fully-executed PPA counter-signed by the utility as a condition precedent to a legally enforceable obligation was held not to be consistent with PURPA as it would allow the utility to circumvent its PURPA obligations by refusing to sign the PPA. *Cedar Creek Wind LLC*, 137 FERC ¶ 61,006 at 32 (2011) ("*Cedar Creek*"). Further, if a utility has refused to negotiate a contract, the FERC has stated that a non-contractual LEO may arise prior to the memorialization of a contract to writing and that imposing a requirement that a QF must have filed a "meritorious complaint" prior to a LEO would also be inconsistent with PURPA and "create practical disincentives to amicable contract formation." *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187 at 40 (2013) ("Grouse Creek"). Finally, the FERC recently expressed its view that a brightline standard requiring a QF to tender an executed IA to the utility would allow the utility to control whether and when a LEO exists, which is inconsistent with PURPA and FERC regulations as "the establishment of a [LEO] turns on the QF's commitment, and *not* on the utility's actions." *FLS Energy*, 157 FERC at 24 (2016) (emphasis in original).

The Commission finds that DEC/DEP's proposed contracting procedures are consistent with this guidance from the FERC as to the meaning of its regulations as well as the Commission's own view of the LEO standard under the FERC's regulations. Notably, in each of these cases, the QF had already undertaken extensive PPA

[19] The Commission notes that it is up to the Commission, not the FERC, to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under North Carolina law. *W. Penn Power Co*., 71 FERC ¶ 61,153 at 61,495 (1995); *see generally Portland Gen. Elec. Co. v. FERC*, 854 F.3d 692 (D.C. Cir. 2017) (explaining the advisory nature of the FERC's non-binding declaratory orders addressing States' implementation of PURPA).

negotiations and, in some cases, had executed and returned a final PPA to the utility at the time the QF asserted that a non-contractual LEO arose. *Cedar Creek*, 137 FERC at 38-39 (describing extensive PPA negotiations between QF and utility and highlighting QF's execution of final draft PPA prior to date QF asserted non-contractual LEO arose); *Grouse Creek*, 142 FERC at 14-15, 37 (describing extensive PPA negotiations and agreement on all material terms such that QFs had "unequivocally committed themselves to sell to the utilities" as of the date FERC held the non-contractual LEO arose); *FLS Energy*, 157 FERC at 4 (asserting that utility and QFs had reached agreement on all material terms of PPAs and QFs had tendered PPAs back to utility as of the date the non-contractual LEO arose). Consistent with these decisions, DEC/DEP's proposed contracting procedures are primarily focused on establishing a clear path toward amicable contract formation between the QF and the utility, while protecting the utility's ratepayers from avoided cost obligations prior to the time the QF is ready, willing, and able to commit to deliver power to the utility. Based upon the clear step-by-step process established in the procedures, the QF will control whether and when to enter into a PPA. Finally, should a utility not adhere to the procedures or otherwise refuse to negotiate with the QF in good faith, the contracting procedures protect the QF's rights to sell power under PURPA by expressly providing that QFs may petition the Commission through an arbitration proceeding to determine the utility's avoided cost rates at the point in time that a non-contractual LEO arose.

While the Commission is establishing the LEO policy most appropriate for North Carolina based upon the current economic and regulatory circumstances in this state, the Commission also notes that other states have recently established or affirmed LEO standards consistent with the contracting procedures process approved herein. For example, in May 2016, the Oregon Public Utility Commission adopted a LEO standard based upon a contracting procedures process, finding that "a LEO exist[s] when a QF signs a final draft of an executable standard contract that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date." *In the Matter of Public Utility Commission of Oregon Staff's Investigation into Qualifying Facility Contracting and Pricing*, Order No. 16-174 at 27; Docket No. UM 1610 (May 13, 2016). The Idaho Public Utilities Commission has also recently approved similar standardized contracting procedures and LEO standards for the utilities in that state. *In the Matter of the Application of Idaho Power Company for Approval and Implementation of Schedule 73, Cogeneration and Small Power Production*, Order No. 33197, Idaho Public Utilities Commission Case No. IPC-E-14-24 (Dec. 29, 2014); *In the Matter of the Application of Avista Corporation for Approval of Proposed Revisions to Schedule 62*, Order No. 33048 at 5-6, Idaho Public Utilities Commission Case No. AVU-E-14-03 (May 30, 2014).

Other states have also approved LEO standards for larger QFs that are notably more conservative than the standard approved by the Commission in this Order. The New Mexico Public Service Commission recently upheld its existing regulation requiring a QF to be already constructed and physically interconnected to the utility's system to establish a LEO. *See Waste Water and Power Production Limited, LLC v. Public Service Company of New Mexico*, New Mexico Public Service Commission Case No. 11-00466-UT (Aug. 3, 2016). Notably, FERC did not declare the New Mexico LEO standard to be inconsistent with its regulations. *See Waste Water and Power Production Limited, LLC*, 158 FERC ¶ 61,015 (2017) (Issuing notice of intent not to act in response to petition for FERC enforcement). Other jurisdictions such as Texas and Tennessee have similarly approved LEO standards that effectively require a QF to be constructed to establish a non-contractual LEO. *Power Res. Group, Inc. v. PUC*, 422 F.3d 231(5th Cir. Tex. 2005) (upholding Texas regulation requiring QF to be capable of delivering power within 90 days to establish non-contractual LEO as being consistent with PURPA); *Mid-South Cogeneration, Inc. v. Tenn. Valley Auth.*, 926 F. Supp. 1327 (E.D. Tenn. pp 1996) (finding that no LEO arose under Tennessee law for an unbuilt QF that was neither bound nor ready, willing, and able to deliver power to Tennessee Valley Authority). In contrast, no jurisdiction known to the Commission has approved a LEO standard similar to the standard proposed by NCSEA and the Public Staff.

As the Commission has approved DEC/DEP's proposed contracting procedures, the Commission does not find NCSEA's and the Public Staff's recommendations to modify the current non-contractual Notice of Commitment Form for larger QFs to be reasonable or appropriate. As discussed above, the evidence in this proceeding is clear that large QFs up to 80 MW are not making an unequivocal commitment or in any way binding themselves to sell power to the utilities under the current Notice of Commitment Form. The Commission does not find a standard where a QF can walk away without obligation to be consistent with the LEO concept established in PURPA. *See Armco Advanced Materials Corp. v. Pa. Pub. Util. Comm'n*, 135 Pa. Commw. 15, 33 (Pa. Commw. Ct. 1990) (a LEO should not arise when "the QF has not yet obligated itself to deliver power and remains free to walk away from the negotiations without liability").

As such, the Commission also does not adopt the Public Staff's and NCSEA's proposed modifications to the current Notice of Commitment Form that a QF may establish a LEO 105 days after submitting a completed interconnection request. The evidence presented by DEC/DEP, the Public Staff, and NCSEA all emphasized the critical importance of completing System Impact Study in order to obtain preliminary ballpark information on the cost and timing required to interconnect a proposed QF generator. The Commission agrees with DEC/DEP that it is increasingly improbable in light of the current level of utility-scale solar QF development and the growing cost and complexity of the interconnection process that a QF will have the information necessary to make a meaningful commitment to sell early in the interconnection process. However, under the contracting procedures process approved by the Commission, to the extent that a QF obtains a CPCN and seeks to make a legally enforceable commitment to sell over a specified term prior to completing the interconnection study process, making such a commitment would be 100% in the QF's control, *i.e.*, the QF can elect to take on the risk and responsibility of delivering power over a specified term by executing a PPA. In this circumstance, the QF, not the utility and customers, should take on the risk that the QF will not meet its future obligations to deliver power over a specified term and the QF developer would be held contractually accountable through the liquidated and/or termination damages provisions of the PPA if it should fail to meet its contractual obligations.

The Commission also notes that DEC/DEP have specifically incorporated the Public Staff's proposed LEO requirement that a QF generator be a Project A or Project B under NCIP Section 1.8 as a threshold requirement to commence PPA negotiations or otherwise establish a LEO under the contracting procedures.

Conclusion

The Commission has carefully considered the evidence presented by the parties and finds and concludes that DEC/DEP's proposed contracting procedures should be approved subject to an opportunity for input on the Notice of Intent to Negotiate Form by the Public Staff, DNCP, and other interested parties. After considering such input, DEC, DEP, and DNCP shall either jointly or individually file with the Commission a proposed final Notice of Intent to Negotiate Form and contracting procedures within 30 days of this Order.

The Commission also recognizes that QFs between 1 MW and 5 MW may have submitted the Sub 140 Notice of Commitment Form since the utilities filed avoided cost rates on November 15, 2016, anticipating that they would have administratively established a LEO under the prior process approved by the Commission in Sub 140. The Commission finds that these QFs should now be subject to the contracting procedures process and should adhere to the step-by-step negotiation process established in the Notice of Intent to Negotiate Form to proceed toward executing a PPA with the utility. However, the Commission also finds it reasonable for these 1 MW to 5 MW QFs transitioning to the negotiated PPA process to be allowed additional time to initially evaluate the utility's avoided costs and terms and conditions. Therefore, the Commission finds and concludes that any QF that previously submitted a Sub 140 Notice of Commitment Form prior to the date of this Order and now submits a Notice of Intent to Negotiate Form within 90 days of this Order shall be eligible for the utility's avoided costs as of the date a LEO was asserted under the Sub 140 Notice of Commitment Form.

For any QF that meets these requirements, the utility shall also not update its avoided cost for a period of 180 days from the date of this Order if the QF proceeds to enter into a PPA within that period.

The Commission also approves DEC/DEP's modified Notice of Commitment Form for small QFs under 1 MW that are eligible for the Utilities' respective standard offer contracts. The Commission finds that the proposed streamlined standard offer LEO form presented in DEC/DEP Freeman Rebuttal Exhibit 1 should be modified to incorporate the Public Staff's recommendation related to a QF potentially withdrawing its LEO, as discussed above. DEC, DEP, and DNCP shall either jointly or individually file with the Commission a proposed modified Notice of Commitment Form within 30 days of this Order. Upon final Commission approval of the streamlined LEO form and the Notice of Intent to Negotiate Form, the Utilities shall place the forms and information on their websites that clearly shows how both small QFs eligible for the Utilities' respective standard offers as well as large QFs may establish LEOs and commit to sell power to the utilities.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-19

The evidence supporting this Findings of Fact is found in DEC/DEP's Joint Initial Statement, the testimony and exhibits of DEC/DEP Witnesses Bowman and Holeman, and the testimony of Public Staff Witness Metz, NCSEA Witness Johnson, and the testimony presented by Witness Holeman during the evidentiary hearing.

DEC/DEP's Joint Initial Statement proposed to amend the standard offer terms and conditions applicable to purchases of electricity from QF generators under Schedule PP and Schedule PP-H in order to more clearly define the circumstances that are considered an "emergency condition" during which DEC and DEP may curtail energy injections from QFs into the utility's electric system. DEC/DEP explained that under FERC's regulations, absent contractual agreement otherwise, a QF selling power pursuant to a long-term contract may be curtailed and purchases discontinued only during "system emergency" conditions. (See DEC/DEP Ex. JIS at 20). DEC/DEP's amended terms and conditions propose to expressly include any circumstance that requires imminent action by DEC/DEP to comply with North American Electric Reliability Corporation (NERC)/SERC Reliability Corporation (SERC) regulations or standards as an emergency condition. (See DEC/DEP Ex. JIS at 30, Ex. No. 4 at ¶ 14). DEC/DEP Witness Bowman testified in support of these amended terms and conditions. (Tr. Vol. 3 at 359).

DEC/DEP Witness Holeman testified extensively regarding DEC's and DEP's independent BA responsibilities to manage system operations and maintain compliance with mandatory NERC/SERC reliability regulations within their separate BAAs. (Tr. Vol. 2 at 62-65). Witness Holeman explained the history of NERC's current regime of over 100 mandatory and enforceable reliability standards, which evolved out of EPACT 2005's response to the catastrophic 2003 northeast blackout. Witness Holeman testified that he is directly responsible for ensuring DEC/DEP's ongoing compliance with the NERC reliability standards. (Tr. Vol. 2 at 84-85).

Specific to DEP's growing experience managing the increasing levels of unscheduled or uncontrolled and non-dispatchable solar QF energy being injected into the BA, Witness Holeman explained how DEP and DEC will be increasingly challenged to maintain compliance with the mandatory NERC BAL-001, BAL-002, and BAL-003 reliability standards. The "BAL" standards are designed to enhance the reliability of each

Interconnection by maintaining frequency within predefined limits every 30 minutes under all conditions, and effectively mandate every BA to balance generation resources to load demand within the BA during each 30-minute reporting period. Witness Holeman specifically highlighted that the BAL-001-2 standard was updated effective July 1, 2016, and now requires BAs to provide reserves for restoring resource-to-demand balance within 15 minutes following a sudden loss of a designated load following generating unit or disturbance event on the BA. He testified that a BA's failure to comply with the BAL reliability standards could result in system emergencies and reliability failures such as unscheduled power flows, unnecessary and automatic firm load shedding, or in a worst-case scenario, cascading outages across the Interconnection. (Tr. Vol. 2 at 85-87).

Witness Holeman further described how DEP's system operators currently have no dispatch control and no day-ahead planning control over the variable energy injections into the BA from solar QF generators. He also explained that by 2018, the DEP system is projected to have 2,200 MW of solar generation injecting unscheduled and unconstrained energy into the BA, and DEP system operators will increasingly be required to manage reliability in a reactive operational mode, with very limited forecast situational awareness of these variable and intermittent solar energy injections into the BA. (Tr. Vol. 2 at 91).

Witness Holeman presented examples of how the growing levels of unscheduled solar QF energy being injected into the DEP BA is requiring system operators to manage both operationally excess and deficit in energy situations to maintain proper frequency in order to avoid potential BAL Standard violations. If the BA experiences too much unscheduled solar QF energy relative to real time load, the system operator must ramp down load following generating resources to the LROL of its Security Constrained Unit

Commitment, which, if exceeded, can then require DEP to mitigate operationally excess energy in order to maintain proper frequency. Growing solar QF energy injections can also increase the risk of a deficit in energy relative to real-time demand in the BA, causing frequency to drop below the scheduled frequency. For example, if a change in weather or other event suddenly caused large volumes of solar QF energy to drop off the system, or in the late afternoon period as the solar energy drops off, and DEP was unable to ramp up its load-following generating resources fast enough, or if DEP were to lose a sizable network generating resource, then there would be a deficit of energy on the DEP system. Under these conditions, Witness Holeman explained that DEP's system would be operating with compromised reliability and be at risk of violating the BAL-001 standard if the BA operated in these conditions for greater than 30 minutes. (Tr. Vol. 2 at 87-89). Witness Holeman testified that these excess and deficit energy reliability impairments are directly correlated with significant amounts of unscheduled solar generation being injected into the BA, without the BA operator having operational control over the facilities. The ability to curtail solar QFs, as provided in the amended terms and conditions, will provide some measure of improved operational control during a potentially imminent system emergency situation. (Tr. Vol. 2 at 92-93).

Public Staff Witness Metz testified to the Public Staff's investigation of the growing operational challenges DEP and DEC are facing to maintain compliance with the mandatory BAL-001, BAL-002, and BAL-003 standards. He testified that the BAL standards help to ensure reliability of each Interconnection, and that violation of any of these standards for more than 30 consecutive minutes constitutes a system emergency, which could damage generators, lead to load shedding, and, in the worst case scenario, collapse the system across the entire Eastern Interconnection. (Tr. Vol. 8 at 114-16). Witness Metz agreed with Witness Holeman's concerns about solar QFs causing energy over- and under-supply that, in turn, can cause over- and under-frequency events and potential violation of the BAL standards. He testified how these events can increasingly pose system operational challenges as the BAs seek to maintain the proper amount of contingency reserves that can be ramped up and ramped down in real time to meet resulting demand/supply imbalances. Witness Metz concluded that continued growth in unconstrained and non-dispatchable generation will only serve to exacerbate current system challenges. (Tr. Vol. 8 at 116-19).

Specific to DEC/DEP's proposed amendment to the standard offer terms and conditions to clarify the utility's curtailment rights in a system emergency,[20] Witness Metz testified that QFs may be curtailed under FERC's regulations in a system emergency, and should treated on a nondiscriminatory basis to other customers of a similar class with similar load characteristics with regard to interruption of service. Witness Metz stated that an imminent violation of any of the BAL Standards would constitute a system emergency under FERC's regulations. In order to ensure that a decision by a utility to curtail QFs is made due to system emergency conditions and on a non-discriminatory basis, Witness Metz explained that the Public Staff is in discussions with DEC/DEP about filing its QF curtailment guidance documents with the Commission along with establishing curtailment events reporting requirements. (Tr. Vol. 8 at 120-24).

NCSEA Witness Johnson testified to his concerns based on Witness Holeman's

[20] While not at issue in the standard offer terms and conditions, Witness Metz also identified that DEC and DEP currently include "dispatch down" provisions, which is a form of curtailment, in their negotiated contracts, which may occur during emergency and non-emergency conditions without compensation up to contractually specified limits. (Tr. Vol. 8 at 120-121).

testimony that DEC and DEP might start declaring a system emergency when solar energy is displacing some of Duke's less flexible generating resources. He suggested that it would be unfair to QFs to allow Duke the option to declare an emergency and stop paying QFs for their energy when the sun is shining and system load happens to be low. He suggested that this situation is both anti-competitive and forces the solar power producers to shoulder too much risk, since there is no limitation specified on how often the "emergency" can be declared, or how much revenue a QF will lose. Witness Johnson also suggests that allowing Duke to curtail solar QFs during a system emergency creates the impression that the system operational problems are being caused by the solar QFs, which, in his view, is not true because DEC and DEP could have built fewer plants with long ramping times, and instead built more quick start combustion turbines and combined cycle plants, with their more rapid ramping and greater operational flexibility. NCSEA Witness Johnson testified that DEC and DEP should investigate other options instead of system emergency curtailments, including further analysis of how DEC's and DEP's pumped storage capacity is managed or the potential for DEC and DEP to negotiate "take or pay" contracts with solar QFs. Specific to the take or pay concept, Witness Johnson suggested that there is potential for operational benefits from paying solar facilities, if some of the solar energy is effectively discarded rather than used and some of the capacity is held back in reserve, to be instantly ramped up and sent to the grid. Witness Johnson qualified his recommendation that these and other potential operational capabilities would be available only during times when the sun is shining, of course. (Tr. Vol. 7 at 323-28).

In his rebuttal testimony, DEC/DEP Witness Holeman provided additional testimony about the impacts to system reliability and risks of non-compliance with NERC's reliability standards, including the more rigorous operating contingency requirements to be imposed on BAs in the upcoming BAL-002 standard, to become effective for enforcement January 1, 2018. Witness Holeman also highlighted the very steep up- and down-ramping requirements that DEP's load following generating units will face as 2,200 MW of solar QF penetrations come online in 2018, as well as the high likelihood of operational curtailments of QFs that will be required in real time to ensure compliance with NERC's reliability standards and to avoid risks to reliable electric service, as additional QFs continue to come online. (Tr. Vol. 2 at 99-110). Witness Holeman also explained the risks and limits of the hourly, as-available non-firm, curtailable transmission paths underlying the Joint Dispatch Agreement between DEC and DEP, which he emphasized is not a tool for DEP and DEP system operators to use to manage balancing, regulating, or operating reserve requirements. Witness Holeman rebutted NCSEA Witness Johnson's recommendation that it was feasible for the DEP BA to rely on the DEC BA's pumped storage assets to manage DEP's system reliability long-term operational commitments and NERC reliability obligations. (Tr. Vol. 2 at 110-12, 141). Witness Holeman also testified that DEC and DEP are currently in the process of developing an operating procedure document for the management of system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis, and committed to share the document with the Public Staff as soon as it is completed and to file such procedures with the Commission after discussions with the Public Staff.

Witness Bowman rebutted Witness Johnson's recommendation that the

Commission mandate DEC and DEP to enter into take or pay arrangements with QFs that results in customers paying for QF solar power that is simply "discarded" or not used to meet system load. She testified that Witness Johnson provides no evidence that any other public service commission has ever approved a take or pay contract in its implementation of PURPA, and that mandating such a proposal in North Carolina based upon current economic and regulatory circumstances would be completely unjust and unreasonable. Witness Bowman also cited to FERC's Order No. 69 to explain that nothing in PURPA requires customers to pay QFs for unused or unneeded energy or capacity. (Tr. Vol. 3 at 417).

During examination by Commissioner Brown-Bland during the hearing, Witness Holeman testified to his 31 years of experience as a system operator and emphasized the significant challenge facing DEP and DEC system operators in the planning horizon under the current operational tool set to ensure system reliability and security as the 2,200 MW of QF solar projected to be online in early 2018 will be the largest aggregate generating resource in the Carolinas. Witness Holeman also highlighted the need for fair, non-discriminatory operating procedures that will provide DEP more centralized operational control to better manage the intermittency and uncertainty increasingly caused by the growing levels of utility scale solar. (Tr. Vol. 2 at 164-66, 173).

Discussions and Conclusions

Based upon the extensive and largely uncontroverted testimony presented by DEC/DEP Witness Holeman and Public Staff Witness Metz regarding DEC's and especially DEP's current operational experience integrating QF solar as well as the growing NERC reliability standard compliance challenges anticipated in the near future, the Commission finds that DEP's and DEC's proposed amended terms and conditions are reasonable and appropriate and should be approved.

For the first time in a biennial avoided cost proceeding, DEC and DEP have presented extensive testimony regarding their obligations under the complex regulatory regime imposed under mandatory and enforceable NERC reliability standards to ensure reliable bulk power system operations, as well as the challenges that DEC's and especially DEP's system operators are experiencing today, and will increasingly experience in the future, as additional QF solar capacity is projected to be installed and unscheduled solar energy is injected into the BAs. Public Staff Witness Metz also testified to the complex system operational challenges associated with the integrating QF solar, and concluded on behalf of the Public Staff that continued growth in unconstrained and non-dispatchable QF solar generation will only serve to exacerbate current system challenges in operating the DEP and DEC BAs. It is also uncontroverted in this proceeding that significant future solar QF growth is forecasted in DEC and DEP in the near future, with 2,200 MW of utility-scale solar projected to be installed in the DEP BA by early 2018. Accordingly, the Commission finds that it is appropriate to provide DEC and DEP the contractual tools needed to more effectively integrate utility-scale solar consistent with the State's obligations to implement PURPA.

The FERC's regulations implementing PURPA specifically provide that a public utility can discontinue or curtail purchasing energy and capacity from QFs during light loading periods and when the utility is confronted with system emergency conditions. *See* 18 C.F.R. § 292.304(f); 18 C.F.R. § 292.307(b). In a "light loading" scenario, a utility may curtail output and discontinue purchases from a QF where "due to operational circumstances, purchases from [QFs] will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself." 18 C.F.R. § 292.304(f)(1) (2016). In order to avoid paying for curtailed QF energy during a light loading period under this section, the utility must have notified each affected QF in time for the QF to cease delivering energy or capacity to the electric utility in accordance with applicable state law or regulation. 18 C.F.R. § 292.304(f)(1) (2016). Notably, however, while this provision aligns with PURPA's intent to only obligate utilities and customers to pay the incremental cost of alternative energy the utility would otherwise generate or purchase from another source, FERC has held that curtailment during light loading periods should only be applied to QFs selling energy on an as-available basis. *Idaho Wind Partners 1, LLC*, 140 FERC ¶ 61,219 at 39 (2012). In the context of curtailment for system emergency conditions, a public utility may discontinue both purchases from and sales to QFs where the purchase from the QF would contribute to such emergency and where the discontinuance of sales to QFs is implemented on a nondiscriminatory basis. 18 C.F.R. § 292.307(b)(1)-(2). FERC's regulations define a "system emergency" as a condition on the utility's system "which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property." 18 C.F.R. § 292.101(b)(4).

The Commission has not previously had an opportunity to consider the system emergency curtailment provision as part of North Carolina's implementation of PURPA, but notes the earlier discussion in this Order that the State's utilities are faced with new and unique economic, regulatory and system operational circumstances related to the recent significant growth in utility-scale QF solar under PURPA. Based upon the record and testimony presented, the Commission agrees with DEC/DEP and the Public Staff that where the Utilities' system operators are operating their load-following generating fleets at the LROL and are confronted with circumstance that requires imminent action by DEC/DEP to comply with mandatory NERC/SERC reliability standards, including but not limited to the BAL standards, that this reasonably constitutes a system emergency where curtailment of QF generators contributing to the emergency condition is warranted.[21]

DEC/DEP have testified that the Companies are currently developing operating procedure to manage system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis, and have committed to share this document with the Public Staff and to then file such procedures with the Commission. The Commission finds that establishing non-discriminatory and transparent system emergency curtailment operating procedures is reasonable, and that DEC/DEP should file its planned system emergency curtailment operating procedures within 30 days of the date of this Order.

The Commission also rejects NCSEA Witness Johnson's recommendations that DEC and DEP seek to better manage the complex operational challenges associated with the growing levels of operationally excess QF solar energy through reliance on DEC's pumped storage resources utilizing the non-firm JDA. As explained by Witnesses Bowman and Holeman during the hearing, DEP and DEC continue to operate as separate BAs and utilities, and each is responsible for its own independent resource planning and

[21] While not directly at issue in this proceeding, the Commission also finds DEC/DEP's inclusion of dispatch down and similar contractual provisions in the non-standard offer PPAs with larger QFs to be reasonable and encourages the utilities to continue to evaluate requiring enhanced contractual rights that will more effectively provide utility system operators scheduling and operational control rights over deliveries of energy by QFs to assure continued reliable electric service in North Carolina.

operations, as directed under the Commission's June 29, 2012 *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, in Docket Nos. E-2, Sub 998 and E-7, Sub 986, approving the merger of Duke Energy and Progress Energy Corporation.[22] (Tr. Vol. 2 at 141; Tr. Vol. 3 at 39). As DEC/DEP Witness Holeman and Public Staff Witness Metz testified, the JDA is an opportunistic, economic, incremental-cost energy transfer tool, which relies on hour-by-hour, as-available, non-firm, curtailable transmission and does not reduce availability of firm transmission for long-term wholesale transactions of other network transmission customers. (Tr. Vol. 2 at 113, 124; Tr. Vol. 8 at 252). While DEP has been able to successfully manage the growing levels of operationally excess energy experienced during a limited, but growing, number of hours in 2016 and now in 2017 using the JDA's economic energy transfer capabilities, both Witness Holeman and Public Staff Witness Metz testified that relying on the JDA poses significant system operational risks of transmission curtailment and was not designed as a long-term solution to manage operationally excess QF solar energy. (Tr. Vol. 2 at 113-14, 124, 141; Tr. Vol. 8 at 125).

Based on the record in this proceeding, the Commission appreciates the efforts DEC's and DEP's system operators are undertaking to manage the new and unprecedented challenges associated with integrating the growing levels of unscheduled solar QF energy into the DEP and DEC BAs to ensure continued reliable and cost-

[22] *See, e.g.,* DEC/DEP Regulatory Condition No. 4.1, which provides that "DEC and DEP acknowledge that the Commission's approval of the merger and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA never being interpreted as providing for:

(a) A single integrated electric system
(b) A single BAA, control area, or transmission system
(c) Joint planning or joint development of generation or transmission
(d) DEC or DEP to construct generation or transmission facilities for the benefit of the other
(e) The transfer of any rights to generation or transmission facilities from DEC to DEP to the other, or
(f) Any equalization of DEC's and DEP' production costs or rates."

effective electric service is maintained for North Carolina ratepayers. Should DEC or DEP determine that new generation or transmission resources or capabilities are needed to effectively manage this solar energy challenge, the Public Utilities Act provides that these public utilities may petition the Commission for a certificate to build additional resources. Otherwise, the Commission finds that the Utilities and their system operators are best suited to make the system planning and real-time BA management and operational decisions needed to reliably and cost-effectively integrate utility-scale solar into North Carolina's electric grid and to maintain compliance with NERC reliability standards.

The Commission also finds NCSEA Witness Johnson's recommendation that the Utilities consider entering into "take or pay" contracts with solar QFs to be unjust and unreasonable to DEC's and DEP's customers and inconsistent with the system emergency curtailment provisions under PURPA. As noted above, only during limited circumstances under the 18 C.F.R. § 292.304(f) light loading curtailment provisions where the QF actually provides energy and capacity to the utility after the utility has failed to provide notice in time for the QF to cease delivering electricity would any payment be owed to the QF. That section is not applicable, however, to the system emergency curtailment provision in 18 C.F.R. § 292.307(b), which provides explicitly that a public utility may discontinue "purchases" form a QF during system emergencies. The Commission also agrees with DEC/DEP Witness Bowman that FERC clearly expressed in *Order No. 69* that PURPA does not require utilities to pay for energy and capacity in excess of their system needs.

> "A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system

> load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, ***the purchase rate should only include payment for the energy or capacity which the utility can use to meet its total system load***. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale."

Order No. 69, 45 Fed. Reg. at 12,219.

Accordingly, Witness Johnson's recommendation that the Commission consider requiring the utilities to enter into take or pay contracts must be rejected as unjust and unreasonable and inconsistent with PURPA.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 20-21

The evidence supporting these Findings of Fact is contained in DEC/DEP's Joint Initial Statement.

In their Joint Initial Statement, DEC and DEP filed Schedules PP-H and PPH-1, respectively, in which they set forth avoided cost rates for run-of-river QF hydro facilities without storage that were 5 MW and less. The avoided cost rates on those Schedules reflected the terms and conditions of the Hydro Stipulation, which was filed on June 24, 2014, in Docket No. E-100, Sub 140. The Hydro Stipulation provided that, because of the state policy supporting small hydro facilities and the relatively small and finite amount of small hydro capacity in the state, DEC and DEP would continue to use the then-approved 2.0 PAF to calculate the avoided cost rates for small hydro QFs of 5 MW or less and that small hydro QFs of 5 MW or less, otherwise eligible for power purchase contracts with DEC or DEP, would have the option of contract terms of 5, 10, and 15 years, with the same hour options that small hydro QFs had in 2014 under DEC's Schedule PP-H and DEP's Schedule CSP-29. In addition, the Stipulation provided that DEC and DEP would include and incorporate the foregoing in their proposed avoided cost rates and proposed standard terms and conditions pertaining to small hydro QFs filed at the Commission until December 31, 2010.

The Commission approved the Hydro Stipulation in its *Sub 140 Phase I Order*. *Sub 140 Phase I*, at 56. No party introduced any evidence disputing that the avoided cost rates shown on DEC's PP-H and DEP's PPH-1 were inconsistent with the Hydro Settlement, and no party introduced any evidence indicating that the Commission should reconsider its prior approval of the Hydro Stipulation. Therefore, based on the foregoing, the Commission finds that Schedule PP-H and PPH-1 are consistent with the Hydro Stipulation and should be approved.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 22

The evidence supporting this Finding of Fact is found in DEC/DEP's Joint Initial Statement and the testimony of DEC/DEP Witnesses Bowman and Freeman.

Witness Bowman testified that DEC/DEP's Joint Initial Statement proposed a clarification to Section 1(e) of the Companies' respective Schedule PP and PP-3 terms and conditions to expressly limit the transfer and/or assignment of the standard offer PPA by a Seller QF to any person, firm, or corporation that is party to any other standard offer PPA under which it sells or seeks to sell power to the Companies as a QF, if that party is located within one-half mile of the original Seller QF. Consistent with DEC's and DEP's existing standard offer, Schedule PP is not available to a QF owned by a customer or affiliate or partner of a customer who sells power to DEC/DEP from another QF of the same energy resource located within one-half mile, as measured from electrical generating equipment, unless the combined capacity is equal to or less than 1 MW (previously 5 MW). Witness Bowman testified that these amendments to the Terms and

Conditions are intended to prevent evasion of this geographic restriction through subsequent consolidation of ownership of QFs after their PPAs under the standard offer have been executed. During the hearing, Witness Bowman explained that the purpose of this clarification to DEC/DEP's standard offer terms and conditions was to avoid gaming of the standard offer, and explained that if a QF developer wants to build a facility or buy a facility within one-half mile then the developers certainly have the opportunity to enter into a negotiated contract. (Tr. Vol. 4 at 18). She did, however, admit, that DEC/DEP did not have any evidence that developers had deliberately attempted to evade this restriction by subsequent consolidation. (Tr. Vol. 4 at 15). Witness Freeman testified that DEC and DEP have seen QF projects change ownership now as many as five times, and that his understanding was that the intent of this provision is that if a QF developer purchased a standard offer project within one-half mile of another standard offer project owned by that developer, then the standard offer PPA would be terminated and the QF would be subject to a negotiated PPA to sell its output.

The Commission finds that this proposed clarification to DEC/DEP's respective Schedule PP terms and conditions is reasonable and appropriate, and is consistent with the original intent of this provision to avoid QF developers from developing or, in this case, owning after commercial operation, multiple standard offer QFs that would exceed the nameplate eligibility of the approved standard offer tariff. The Commission does not find it reasonable or appropriate to allow the existing half-mile restriction on ownership in DEC/DEP's standard terms and conditions to be evaded through subsequent consolidation of QF ownership after their PPAs under the standard offer have been executed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-24

The evidence supporting this Findings of Fact is contained in the direct and rebuttal testimony of DEC/DEP Witness Snider, the testimony of Public Staff Witness Hinton, and the testimony of NCSEA Witness Johnson.

Witness Snider testified that while he designed and supported generic avoided cost rates under the peaker method to apply to all QFs eligible for the standard offer, the recent high penetrations of QF solar resources as well as proposed solar QF projects under development had caused DEC/DEP to more specifically evaluate the impact of solar QFs on DEC/DEP's planning and reliability. He described DEC/DEP's 2016 resource adequacy studies and recent shift to winter planning, emphasizing that the load and resource balance has changed drastically in the past two-to-three years, driven in large part by the high penetration of solar. (Tr. Vol. 2 at 209-10, 216). He also noted that DEC/DEP may need to consider the ancillary services impact of high levels of must-take solar when considering additional generation resources to satisfy winter reserve margin requirements, and to ensure adequate system ramping capability and operational flexibility. (Tr. Vol. 2 at 209-210). Witness Snider also noted that the generic avoided capacity rates filed in this proceeding tend to over-compensate solar QFs in excess of the capacity actually avoided due to the broad on-peak hour definitions under Options A and B of Schedule PP. Witness Snider explained that DEC/DEP intended to evaluate these solar-specific issues in the context of negotiated PPAs with larger QFs and in the next biennial proceeding. (Tr. Vol. 2 at 218-19).

Public Staff Witness Hinton recommended the Commission consider a solar-specific adjustment to avoided energy rates in this proceeding. Witness Hinton cited a study conducted by Crossborder Energy and introduced by NCSEA in the 2014 avoided cost proceeding ("Crossborder Study"), analyzing whether the typical diurnal solar profile has a higher value than a flat block of power utilized in the peaker method for generic QFs, in light of the fact that solar output to some extent may coincide with higher cost off-peak hours relative to other off-peak hours. Witness Hinton stated that the Public Staff had agreed with NCSEA's Witness Tom Beach in Sub 140 with regard to the potential positive impact on off-peak energy rates of a solar specific profile. Witness Hinton also testified that in the Sub 140 Phase I proceeding, the Public Staff conducted discovery where DEP, DEC, and DNCP had estimated that the off-peak energy rates under Option B would increase between 8% and 10% if the definition of off-peak hours was aligned with the load profile of solar QFs. While Witness Hinton acknowledged that the Commission declined to accept NCSEA's and the Public Staff's recommendation in Sub 140 Phase I, he explained the Public Staff believes that this concept deserves further consideration, suggesting that the energy provided by solar facilities during off-peak daylight hours has value that is not currently fully recognized and properly allocated in off-peak avoided energy rates. (Tr. Vol. 8 at 78-79).

Witness Hinton further explained that the existing PROSYM and PROMOD production models that generate the avoided energy rates over 8,760 hours a year are best suited to a QF that can generate energy during all of the on-peak and off-peak hours of the day and night. A 24-hour dispatched QF generally has its lowest marginal costs during the late night hours and early morning hours when base load plants with the lowest marginal costs are operating. Witness Hinton suggested that while he believed this was appropriate for a landfill gas QF, it is inappropriate for solar facilities whose generation helps avoid a utility's marginal production costs during daylight hours when the marginal costs are generally higher. He reported that the Public Staff had conducted a preliminary analysis of the PJM DOM Zone LMPs and DEC's and DEP's day-ahead lambdas, and found that the 8% to 10% range proposed in the Sub 140 proceeding continues to be a reasonable estimate of this added benefit. Based on this analysis, Witness Hinton recommended that DEC, DEP, and DNCP submit a separate avoided energy rate for solar that more accurately reflects the marginal costs for solar QF generation during daytime hours. (Tr. Vol. 8 at 80).

NCSEA Witness Johnson testified that in proposing to retain their existing on-peak and off-peak hours, the Utilities are proposing to continue to use very broad time periods. He expressed concern that if the Utilities continued to resist adopting technology-specific rates, other small power producers, such as wind, methane from landfills, hog or poultry waste, and non-animal biomass could be penalized for problems resulting from solar energy. Witness Johnson recommended that the Utilities be required to propose changes to more precisely tailor their QF rates or improve price signals to incent solar providers to operate at different times. (Tr. Vol. 7 at 303-05).

In rebuttal, Witness Snider testified that, given the large increase in solar QFs in the DEC/DEP territories, evaluating solar specific avoided cost rates for larger QFs is appropriate. Witness Snider additionally believed that advancing a solar-specific rate in a standard offer filing in a subsequent avoided cost proceeding may be appropriate. With respect to the factors that the Commission should consider regarding a solar QF's specific characteristics and impact on energy value, Witness Snider explained that generic QF rates under the peaker method apply to any PURPA QF eligible for the standard offer, and the energy value assumes an equal amount of generic QF generation is available in every hour. Witness Snider noted that generation must be available and dispatchable to meet the dynamic needs of the consumer, which change minute-to-minute. A utility system can only accommodate a finite amount of intermittent generation that does not follow load. The net impact of a large amount of this type of generation on a given system results in the need for additional operating reserves and other operating adjustments. Witness Snider further stated that DEC/DEP were not including the cost of these additional operational adjustments in the calculation of the filed standard offer rates for small QFs in this proceeding. However, he emphasized that the costs for such additional operations are a growing concern and should be analyzed for larger QFs. (Tr. Vol. 2 at 261).

Witness Snider outlined how the Companies would implement a solar-specific energy rate if directed to do so. He explained that to calculate the energy specific portion of the avoided cost rates for solar QFs, the Companies would perform two production cost runs – one with, and one without, 100 MW of free solar generation using a general diversified solar profile. He testified that the use of a solar-specific profile could better represent the actual system marginal energy benefits associated with incremental solar generation as opposed to the generic energy rate that assumes equal production in all hours. (Tr. Vol. 2 at 262).

Witness Snider disputed Public Staff Witness Hinton's claim, however, that solar off peak rates would increase between 8% and 10% due to the diurnal profile of solar coinciding with higher off peak hours. Witness Snider testified that DEC/DEP had analyzed producing an avoided energy rate under the traditional peaker method, but altered to include only a daylight hours solar load shape using a free 100 MW solar load profile to generate the associated energy, rather than a constant 100 MW as traditionally used in calculating the standard offer energy rate design. Based on this analysis, a solar-specific energy rate that more precisely calculates the energy value of incremental solar based on the load characteristics of a solar resource would result in avoided energy rates that on an annual average would be approximately 10% lower than the rates solar QFs are receiving under the generic small QF standard offer that assumes constant energy production around the clock. (Tr. Vol. 2 at 263).

Witness Snider then discussed the factors that led to a lower avoided energy cost rate using a solar-specific profile. First, he noted that the non-coincident nature of the solar shape with DEC/DEP's loads contributes significantly to the lower rate. He pointed to his Figures 7 and 8 in his rebuttal testimony. (Tr. Vol. 2 at 265-66). Figures 7 and 8 illustrate that peak load typically occurs between 7 AM and 8 AM in the winter (January) and between 4 PM and 5 PM in the summer (July). The peak for solar output typically occurs between 1 PM and 2 PM in the winter and between 2 PM and 3 PM in the summer. Witness Snider highlighted that on winter mornings, solar generation starts providing energy to the system just as load is decreasing. During winter evening hours, solar output begins to decline just as load is rebounding. He then explained that solar aligns better with load in the summer, but solar output still begins to decline as system demand is growing toward the afternoon peak. Witness Snider pointed out that solar resources are only available on a varying basis in approximately 55% of all hours in the year. In addition, solar generation only moved in the same direction as load about half those hours while moving in the opposite direction the other half. Figures 7 and 8 show that solar is moving in the opposite direction of customer demand during critical peak hours when energy demand is peaking. (Tr. Vol. 2 at 264-66). Witness Snider then explained Figures 9 and 10 in his rebuttal testimony, which show that as more solar is added to the system, the more non-coincident the solar shape becomes versus the load profile. (Tr. Vol. 8 at 266-68).

Witness Snider further testified that because a solar profile is not coincident with load, it lacks coincidence with the DEC/DEP's highest marginal cost hours in both winter and summer. Witness Snider's Figures 11 and 12 illustrated that solar is not producing at high levels during the Companies' highest system marginal costs. These Figures also depicted that solar is not fully available during the Option B on-peak hours for non-summer months. Witness Snider testified that the current energy rate structure, which provides solar with a rate based on a flat 100 MW load profile, effectively over-credits solar QFs for energy during the on-peak hours. (Tr. Vol. 268-69).

With respect to the capacity value of solar, Witness Snider stated that DEC/DEP would strive to align the capacity rate paid to solar with the amount of avoided capacity that the solar resource will produce. To that end, the Companies would account for the unique characteristics of a large-utility scale solar-specific QF on the system outside of the standard QF rate offering. Witness Snider noted that a solar QF is intermittent, non-dispatchable, and not capable of following customer load. Moreover, Witness Snider continued, during high demand periods, solar is ramping up when peak loads are declining and declining when customer demand is increasing. (Tr. Vol. 8 at 271).

Witness Snider concluded that, as NCSEA Witness Johnson had suggested, using a solar-specific load profile to calculate negotiated QF rates along with a potential change in subsequent biennial avoided cost proceedings will provide more precise price signals to QFs that reflect the specific characteristics of the QF as envisioned by PURPA. (Tr. Vol. 2 at 271).

During the hearing, Witness Snider testified on cross-examination by Cypress Creek that DEC/DEP view it as appropriate to include costs associated with solar QFs in negotiated PPAs that they do not include in standard offer PPAs. Witness Snider explained that the currently proposed avoided cost rates in the standard offer are technology agnostic, but that it may be appropriate with the larger QFs to account for the specific characteristics of that QF. He clarified that DEC/DEP were not proposing to include an ancillary service charge in the standard rates in this proceeding as the Companies had proposed in Sub 140, Phase I, but he noted that it would be appropriate to consider evaluating including such ancillary costs outside of the standard offer. (Tr. Vol. 4 at 21-22). In responding to examination by the North Carolina Attorney General's Office, Witness Snider explained that PURPA contemplates a solar-specific rate, wherein the attributes of that specific technology are included in the rate can be appropriate. Witness Snider also noted that the amount of capacity that a utility could actually avoid building as a result of a generic QF is very different from how much capacity a solar QF avoided. Witness Snider concluded that the standard offer rates, as filed, still paid very well for capacity, even though very little capacity will actually be avoided through additional solar QFs. Thus, Witness Snider indicated that if DEC/DEP adopted technology-specific avoided cost rates, those are areas that will need to be addressed for large QF negotiations to more appropriately value the QF's capacity and energy. (Tr. Vol. 4 at 53-54).

Discussion and Conclusions

As previously discussed by the Commission in this Order, the economic and regulatory circumstances associated with the significant solar QF development in North Carolina necessitates evolving the Commission's implementation of PURPA at this time. While the Commission's determinations in this proceeding are focused on the methodological and policy considerations that support just, reasonable and non-discriminatory standard offer rates, the significant ongoing growth in PURPA-driven utility scale solar development in excess of the standard offer also presents new challenges and issues for the Utilities and the Commission to analyze.

In its original rulemaking *Order No. 69*, FERC explained that standard rates for purchase may differentiate among QF technologies on the basis of supply characteristics, while also recognizing that administrative efficiency of setting generic standardized avoided costs that do not take into account the specific characteristics of these small QFs is appropriate even if a deviation in value from true avoided costs results.

> [FERC] is aware that the supply characteristics of a particular facility may vary in value from that average rate set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction cost associated with administration of the program would likely render the program uneconomic for this size of [QF].

Order No. 69, 45 Fed. Reg. at 12,223. In describing the avoided costs rates to be paid to larger QFs, FERC also emphasized that a QF's capacity and energy supply characteristics could be taken into account in analyzing whether the QF provided capacity value and in calculating the incremental energy value to be avoided by the QF. *Id.* at 12,224 (describing the specific capacity value considerations of wind, solar, and biomass QFs). FERC also established through 18 C.F.R. § 292.304(e) specific factors that could affect the rates for purchases from QFs, while emphasizing that the selection of a methodology setting avoided costs is best left to the State Commissions charged with implementing PURPA's must-purchase provisions. *Id.* at 12,226. As the Commission has already noted in this Order, FERC recently reiterated in the *Windham Solar* decision the appropriateness of including factors such as the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity in establishing avoided cost rates, which FERC also recognized could be lower for purchases from intermittent QFs than for purchases from firm QFs. *Windham Solar*, 157 FERC at ¶6 (2016).

Based on the record in this proceeding, the Commission declines to accept Witness Hinton's recommendation that DEC and DEP be required to submit a separate avoided energy rate for solar QFs that more accurately reflects the avoided marginal costs from solar generation in the daylight hours. As Witness Hinton notes, the Commission reviewed this issue in Sub 140 Phase I, and similarly rejected this proposal on the grounds that it "isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources." *Sub 140 Phase I Order* at 62. The Commission adopts the same conclusion here. The Commission also disagrees with Witness Hinton's assertion that this issue is more of a modeling or allocation issue than a solar integration one.

The Commission, however, finds merit in the recommendations of Witnesses Hinton, Johnson, and Snider, that it is appropriate based upon current economic and regulatory circumstances to evaluate solar-specific avoided costs for larger QFs, including the need to provide stronger, more precise on-peak and off-peak price signals in the QFs tariffs to encourage solar QFs to provide more of their power when it is most valuable. For example, Witness Snider provided an alternative method of calculating the energy value of solar more precisely, taking into account the load characteristics of a solar resource. These characteristics associated with solar-specific profile included the non-coincident nature of the solar production shape with DEC/DEP's load and the fact that solar is not producing at high levels during the Companies' highest system marginal costs periods. Witness Snider's testimony appeared to show that QFs with solar generation profiles were being over-credited for energy during on-peak hours. Moreover, Witness Snider highlighted solar's intermittency and the fact that it does not follow the Companies' intra-day load curve such that it may provide limited operational capacity value. The Commission agrees with Witness Snider that the culmination of all of these specific characteristics of solar QFs should be considered when developing solar-specific avoided costs to better meet the objectives of PURPA.

To that end, the Commission recognizes that PURPA provides utilities with the ability to consider factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity in establishing avoided cost rates for purchases from larger QFs, including solar QFs. The Commission expects the Utilities to evaluate these issues in developing avoided energy and avoided capacity rates for solar QFs and, as appropriate, other larger QFs that seek to sell power at avoided cost under PURPA. The Commission also directs DEC/DEP to consider evaluating a solar-specific standard offer rate design, accounting for the costs and benefits of solar production by small QFs 1 MW or less, in the next avoided cost proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 25

The evidence supporting this Findings of Fact is found in DEC/DEP's Joint Initial

Statement, the testimony and exhibits of DEC/DEP Witnesses Yates and Bowman, and the testimony of Public Staff Witnesses Hinton.

In its Joint Initial Statement, DEC/DEP requested the Commission initiate a separate proceeding, with interested stakeholders, to collaborate on the development of a renewable energy competitive solicitation procurement process for North Carolina.

DEC/DEP Witness Yates testified that DEC/DEP have been increasingly challenged to maximize the reliable and economic operation of the energy grid under the current PURPA regime as the utilities have minimal input on need, location, timing, or size of QF generation and no ability to dispatch and only limited emergency rights to curtail QF generators. (Tr. Vol. 2 at 27-28). Witness Yates highlighted DEC/DEP's desire to transition to a competitive bidding process for utility-scale solar to ensure the most attractive and cost-efficient projects are built and to allow DEC/DEP improved operational control of utility-scale solar through dispatch and curtailment rights. (Tr. Vol. 2 at 29).

DEC/DEP Witness Bowman also testified in support of transitioning away from the current uncontrolled PURPA standard offer-driven solar development business model and towards optimizing DEC's and DEP's solar procurement in a better managed and sustained way for the benefit of customers. She highlighted DEC/DEP Witness Holeman's growing operational concerns and explained that PURPA imposes operational limitations on DEC/DEP's management of QF resources by limiting the utility's ability to curtail its purchase of energy or capacity from a QF to a system emergency (absent contractual agreement otherwise). Without operational dispatch and contractual curtailment rights, she testified how system operators cannot readily manage the unconstrained solar power that they must take under PURPA. In contrast, Witness Bowman explained that improved curtailment and dispatch capability will be incorporated into PPAs procured through the competitive procurement, allowing system operators to better plan for, manage, and operate their systems. (Tr. Vol 3 at 364-66). The Companies envision a process that allows DEC and DEP to plan where the new solar generation is located, while offering longer term contracts and procurement of an established amount of solar MW as an incentive to add additional new solar installations in a thoughtful and managed process overseen by an independent third party. Witness Bowman stated that a competitive solicitation will lower costs for customers, provide improved operational controls, and open a new market for solar facilities outside of the current PURPA standard offer. (Tr. Vol. 3 at 366).

Public Staff Witness Hinton testified that the Public Staff supports the use of market-based approaches to determining the most cost-effective options for utilities to meet their customer's needs, as well as avoided cost rates, provided that the competitive bidding process is appropriately structured and an independent evaluator is utilized. (Tr. Vol. 8 at 63). Witness Hinton noted that the Public Staff had previously advocated that the Commission and the utilities utilize competitive bidding to a greater degree to meet future capacity needs and cited to competitive procurement process best practices developed by the National Association of Regulatory Utility Commissioners ("NARUC"). Witness Hinton also testified that competitive procurement processes were relied upon by Dominion, DEC and DEP in the 1990s for PURPA compliance, while, more recently, all three utilities had utilized RFPs for REPS compliance, voluntary renewable energy procurement, and complying with other mandates but had not requested approval of a Commission-recognized active solicitation for PURPA compliance purposes. (Tr. Vol. 8 at 63-64). The Public Staff's position is that if the Commission were to open a separate docket as requested by DEC/DEP to establish a competitive procurement process, then the RFP should incorporate the NARUC best practices, should be based on needs identified in the utilities' IRPs, and give equal consideration for all resources. (Tr. Vol. 8 at 64).

Discussion and Conclusion

DEC/DEP have requested that the Commission initiate a new proceeding pursuant to which those utilities would work with interested stakeholders to establish a competitive bidding process to procure energy and capacity from larger QFs not eligible for DEC/DEP's standard offer tariff. DEC/DEP emphasize this new procurement process would allow DEC/DEP to obtain more cost-effective solar energy resources and will provide better operational control through improved curtailment and dispatch capabilities. DEC and DEP effectively advocate for evolving the current PURPA framework in North Carolina away from the current process of negotiating non-standard PPAs with large solar QFs that are currently offering to provide non-dispatchable capacity and to deliver unscheduled energy at DEC/DEP's current Commission-approved avoided costs.

The Public Staff generally expresses support for a competitive procurement process tied to the capacity needs identified in the utilities' IRPs, emphasizing that all three utilities relied on competitive bidding to procure new capacity, including QF-sponsored capacity, at various times during the 1990s.

The Commission initially notes that the option to initiate a formalized competitive bidding process to procure a utility's next needed block of capacity has long been available to the electric utilities in North Carolina. *See, e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 6, 11, Docket No. E-100, Sub 57 (March 10, 1989) (recognizing VEPCO's competitive bidding process and directing non-hydro non-standard QFs desiring to sell capacity to participate in the bidding process). As QFs (along with non-QFs) would have an equal opportunity to offer capacity into such a competitive procurement process to meet the utility's incremental capacity needs, the Commission has previously held that a utility may refuse to negotiate with larger non-standard QFs during the time the utility has an "active competitive bidding process underway," which would be determined after motion by the utility and approval by the Commission. *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 26-27, Docket No. E-100, Sub 74 (Sept. 1, 1995). This view prevailed until the 2003 avoided cost proceeding, where the Commission evolved the options available to large QFs when a utility has a Commission-recognized active solicitation to include: (a) participating in the utility's competitive bidding process; (b) negotiating a contract and rates with the utility; or (c) selling energy at the utility's Commission-established variable energy rate. *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 5, 18-19, Docket No. E-100, Sub 96 (Oct. 29, 2003). Notably, in that proceeding, the Commission was confronted with unique circumstances where numerous existing PURPA contracts were expiring and certain parties disputed whether a near term capacity need existed and, relatedly, whether at least variable capacity payments should be required for these pre-existing QFs if they committed to deliver power for a two year period. *Id.* at 16. None of the utilities had an active competitive bidding process approved by the Commission in 2003, so the issue of whether a competitive bidding process and negotiated large QF rates should both be available was not squarely before the Commission. Since that time, the Commission's biennial avoided cost orders have generally recognized that utilities may initiate PURPA-compliant competitive bidding processes to meet its next incremental capacity need, but no utilities have initiated such a process to procure future capacity.

The Commission recognizes that DEC's and DEP's request to initiate a competitive procurement stakeholder process is intended to promote more sustainable and cost effective procurement of QF solar and other resources for the benefit of customers as well as to provide DEC/DEP's system operators more robust operational control over large solar generators than exists under the current PURPA framework in order to assure continued cost-effective and reliable electric service. At this time, however, the Commission is not inclined to open a new proceeding in light of pending legislation that would amend the Public Utilities Act to provide a competitive procurement framework for new renewable energy resources in DEC and DEP.[23] If a new competitive procurement framework is not established through legislative enactment in the near future, DEC and DEP may elect to formally petition the Commission to initiate such a proceeding or the Commission may do so on its own motion at that time.

The Commission also notes that DEC or DEP may also initiate a competitive bidding process to meet the utility's next general capacity need. As discussed above, initiating such a comprehensive competitive procurement process could also potentially

[23] Part II of 2017 H. 589, as passed by the North Carolina House of Representatives on June 7, 2017, would legislatively establish a framework for the competitive procurement of 2,660 MW of renewable energy between DEC and DEP, if ultimately enacted into law.

be used to satisfy the utility's incremental capacity requirement under PURPA, thereby requiring large QFs to bid into the competitive procurement in order to offer capacity to the utility while an approved competitive solicitation is underway. DEC/DEP may also continue to consider RFPs and other competitive procurements of solar and other renewable resources as cost-effective procurement options to meet North Carolina's REPS requirements or potentially other future renewable energy compliance obligations. Through that process, DEC and DEP may contract for more robust operational control over large solar generators than is provided for under the PURPA framework that exists today.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's and DEP's Schedule PP and Schedule PP-3, as discussed and modified in this Order, are approved to be offered to all non-hydroelectric QFs and hydroelectric QFs with storage capability contracting to sell 1 MW or less capacity. Schedule PP shall offer these QFs fixed long-term levelized capacity payments for a 10-year term as well as the following avoided energy rate options to be selected by the QF prior to beginning of the specified term (a) a fixed 2-year avoided energy rate to be updated in future biennial avoided cost proceedings by order of the Commission; or (b) the option to fix the current 2-year levelized avoided energy rate for the 10-year term. DEC and DEP shall file modified Schedule PP and PP-3 rates to reflect any amendments to the tariff that are necessary to provide QFs these options within 15 days of the date of this Order. The standard levelized 10-year rate 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.

2. That DEC's Schedule PP-H and DEP's Schedule PPH-1, as discussed in this Order, are approved to be offered to all hydroelectric QFs with no storage capability owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity.

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

may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

4. That DEC's and DEP's calculations of its avoided capacity rates are reasonable and appropriate and DEC and DEP shall be required to offer levelized avoided capacity rates that are calculated to pay QFs for avoided capacity starting only in the first year that each public utility's most recently filed IRP identifies a capacity need.

5. That the methodology utilized by DEC and DEP to calculate their avoided energy rates is reasonable and appropriate, including the manner in which DEC and DEP have relied upon natural gas and coal forward market price data and long-term fundamental forecasts of future commodity prices for purposes of calculating Schedule PP-H and Schedule PPH-1, respectively. DEC's and DEP's commodity price forecast methodology has been constructed in a consistent manner with those utilized in their most recently filed IRPs, and the Commission finds that the Utilities should continue to maintain reasonable consistency with regard to their reliance upon forward market price data and long-term fundamental forecasts between future IRPs for planning purposes and in future biennial avoided cost proceedings. The Utilities should also identify any future methodological changes to their reliance upon forward commodity market data and fundamental forecasts in a future IRP proceeding before those changes are proposed to be incorporated in future avoided cost calculations.

6. That DEC's and DEP's proposed modified Notice of Commitment Form for small QFs under 1 MW that are eligible for the Utilities' respective standard offer contracts is approved, subject to the Utilities incorporating the Public Staff's recommendation that a QF that withdraws its Notice of Commitment Form shall be

precluded from being able to establish a new LEO for two years from the date of the withdrawal. During this period, the QF would continue to be eligible for the utility's "as available" energy rates. DEC, DEP, and DNCP shall either jointly or individually file with the Commission a proposed modified Notice of Commitment Form for small QFs under 1 MW within 30 days of this Order incorporating this modification to the Form presented by DEC and DEP in this proceeding.

7. That DEC's and DEPs proposed contracting procedures for larger QFs are reasonable and should be approved subject to an opportunity for input on the Notice of Intent to Negotiate Form by the Public Staff, DNCP, and other interested parties. After considering such input, DEC, DEP, and DNCP shall either jointly or individually file with the Commission a proposed final Notice of Intent to Negotiate Form and contracting procedures within 30 days of this Order.

8. That QFs not eligible for the Utilities' respective standard offer tariffs, including any QFs between 1 MW and 5 MW that have submitted the currently-approved Notice of Commitment Form since the Utilities filed avoided cost rates on November 15, 2016, shall now be subject to the contracting procedures process approved in this Order and should adhere to the step-by-step negotiation process established in the Notice of Intent to Negotiate Form to proceed toward executing a PPA with the interconnecting utility. Any 1 MW to 5 MW QFs transitioning to the negotiated PPA process that previously submitted a Sub 140 Notice of Commitment Form between November 15, 2016, and the date of this Order and now submits a Notice of Intent to Negotiate Form within 90 days of this Order shall be eligible for the utility's avoided costs as of the date a LEO was asserted under the Sub 140 Notice of Commitment Form. For any QF that

meets these requirements, the utility shall also not update its avoided cost for a period of 180 days from the date of this Order if the QF proceeds to enter into a PPA within that period.

9. That upon final approval by the Commission, the Utilities shall place the modified Notice of Commitment Form for small QFs under 1 MW as well as the Notice of Intent to Negotiate Form and contracting procedures for large QFs on their websites in order to provide information to both standard offer and larger QFs regarding how to proceed to a PPA or otherwise establish a non-contractual LEO, as addressed in this Order.

10. That after discussions with the Public Staff, DEC and DEP shall file its planned system emergency curtailment operating procedures with the Commission within 30 days of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ____ 2017.

NORTH CAROLINA UTILITIES COMMISSION

M. Lynn Jarvis, Chief Clerk