DUKE ENERGY®

Kendrick C. Fentress
Associate General Counsel

Mailing Address:
NCRH 20/P. O. Box 1551
Raleigh, North Carolina 27602

o: 919.546.6733
f: 919.546.2694

Kendrick.Fentress@duke-energy.com

April 10, 2017

VIA ELECTRONIC FILING

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

Re: Rebuttal Testimony in Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities - 2016
Docket No. E-100, Sub 148

Dear Ms. Jarvis:

Enclosed on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC is the Rebuttal Testimony and Exhibits of Kendal C. Bowman, Glen A. Snider, John S. Holeman, III, and Gary R. Freeman in the above-referenced docket.

Portions of Mr. Snider's Rebuttal Testimony contain certain confidential information, including financial information used to develop the Companies' filed avoided cost rates, and business or technical information filed confidentially in support of the Companies' respective 2016 Integrated Resource Plans. Such information designated by the Companies as confidential qualifies as "trade secrets" under N.C. Gen. Stat. § 66-152(3). If this commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to ratepayers. The Companies respectfully request that the Commission treat the marked information as confidential and protect it from public disclosure pursuant to N.C. Gen. Stat. § 132-1.2. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

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

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's filing of Rebuttal Testimony and Exhibits of Kendal C. Bowman, Glen A. Snider, John S. Holeman, III, and Gary R. Freeman in Docket No. 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 10th day of April, 2017.

By: Kendrick C. Fentress

Kendrick C. Fentress
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
Tel: 919.546.6733
Kendrick.Fentress@duke-energy.com

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	)))))	REBUTTAL TESTIMONY OF KENDAL C. BOWMAN ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kendal Crowder Bowman. My address is 410 South Wilmington Street, Raleigh, NC 27601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President Regulatory Affairs and Policy North Carolina for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively the "Companies"), which are wholly owned subsidiaries of Duke Energy Corporation.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of the Companies on February 21, 2017.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. No, I am not.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to address the arguments made by other parties pertaining to the Companies' recommendations to evolve North Carolina's implementation of the Public Utility Regulatory Policies Act ("PURPA") to reflect the current economic and regulatory circumstances in the State. Specifically, I rebut the arguments made by North Carolina

Sustainable Energy Association ("NCSEA") Witness Ben Johnson and Witness Carson Harkrader that the Commission should not revise its current PURPA policies as applied to the standard terms and conditions at issue in this docket. I also rebut the testimony of Southern Alliance for Clean Energy ("SACE") Witness Thomas Vitolo and NCSEA Witnesses Johnson and Harkrader pertaining to the eligibility cap for standard avoided cost contracts by explaining that the Companies' proposed 1 megawatt ("MW") eligibility cap is consistent with PURPA and in the best interest of our customers. Along with Witness Gary R. Freeman, I respond to the Public Staff's request for additional information on the Companies' current and proposed process for negotiating power purchase agreements ("PPAs") with qualifying facilities ("QFs").

I also address other parties' arguments that the Companies' proposed 10-year standard offer PPA rate design, including the biennial updating of the avoided energy rate, should not be adopted in this proceeding. Specifically, I explain why adjusting the Companies' avoided energy rates every two years as part of a longer, fixed-term purchase agreement appropriately balances the need to encourage QF development with the risk of overpayments by our customers. However, I also propose a compromise "alternative option" that would allow small QFs eligible for the Companies' standard offer to fix the two-year energy rate for the full 10-year term as an interim solution while the Companies continue to evaluate the alternative options proposed by Public

Staff Witness John R. Hinton to mitigate long-term forecast risk of overpayment by customers between now and the next biennial proceeding.

I also provide legal justification for recognizing the avoided capacity value only in the years in which the Companies' integrated resource plans ("IRPs") show an actual capacity need, as well as the Companies' proposed modification to its terms and conditions to allow for non-discriminatory curtailment of QF energy during system emergencies. Finally, I address the Public Staff's recommendation for the Commission to direct the Companies to develop a separate avoided energy rate for solar QFs as not appropriate in the current proceeding, but a reasonable directive for consideration in the next biennial avoided cost proceeding if all avoided costs and potential benefits of incremental solar QF generation on the Companies' systems are taken into account.

II. THE RECORD IN THIS PROCEEDING DEMONSTRATES THAT NORTH CAROLINA IS AT A CROSSROADS WITH RESPECT TO CONTINUATION OF THE COMMISSION'S LONG-HELD PURPA POLICIES

Q. PLEASE REINTRODUCE THE COMPANIES' POSITIONS WITH RESPECT TO EVOLVING THE STATE'S IMPLEMENTATION OF PURPA TO BETTER MEET THE PUBLIC INTEREST.

A. The Commission's implementation of PURPA over the past decade has been designed to encourage development of QF generators, including utility-scale solar generators with a nameplate capacity of 5 MW or less, by requiring the Companies and Dominion North Carolina Power ("DNCP" and together with the Companies, the "Utilities") to offer standard 5-, 10-, and 15-year, long-term levelized fixed rate PPAs. In my prefiled direct testimony, however, I described the unprecedented surge in utility-scale solar QF generators, including hundreds of solar projects sized between 4 MW and 5 MW that have interconnected and are now selling energy to the Companies pursuant to Commission-approved long-term PURPA avoided cost rates. My prefiled direct testimony and the direct testimony of Companies' Witnesses Lloyd M. Yates, Glen A. Snider, John Samuel Holeman III, and Witness Freeman, detailed the Companies' experiences and challenges resulting from this explosive solar QF growth in North Carolina. We explained how this surge of solar development has resulted in, and will continue to result in, long-term financial impacts to our customers as solar QFs 5 MWs and less have "locked into" long-term fixed energy and capacity rates that are higher than the Companies' current avoided cost rates. Moreover, we discussed the Companies' growing experiences operating the DEC and DEP balancing authorities ("BA") in parallel with a rapidly-evolving PURPA-driven, increasingly solar-only, renewables environment and how the influx of intermittent solar QFs is challenging the Companies' ability to plan and operate their generation fleets, manage their transmission systems, and assure reliable power is delivered to our customers.

The Commission has recently stated that "the nature of these recurring, biennial proceedings has always required consideration of current economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation."[1] Today's economic and regulatory circumstances, which the Companies described in their Joint Initial Statement and prefiled direct testimony, justify a comprehensive review of the Commission's implementation of PURPA. The Companies' recommended modifications to the standard offer are a needed first step in a longer transition to a more "well-planned and coordinated" process that balances PURPA's goal of encouraging QF development with the dual challenges of integrating solar into our system and aligning the costs our customers are ultimately paying for solar QF power with the value they are receiving.

Q. DO THE PARTIES FILING TESTIMONY IN THIS PROCEEDING GENERALLY AGREE THAT THE UTILITIES HAVE EXPERIENCED RAPID AND EXPLOSIVE GROWTH IN SOLAR QF DEVELOPMENT?

A. Based upon my review of the testimony and comments filed in this proceeding, no party disputes that North Carolina has experienced a surge in solar QF development growth over the past few years. In addition to the Companies' experiences described in their testimony, DNCP Witness Scott Gaskill reported in his prefiled direct testimony that, since February 2014, distributed solar in DNCP's North Carolina service territory has also increased significantly.[2] The Public Staff, after its review and investigation into the

1 *Order Denying Motion* at 3-4, Docket No. E-100, Sub 148 (Jan. 18, 2017).

2 DNCP Gaskill Testimony, at 6-9.

Utilities' Initial Statements and direct testimony, similarly noted the recent "tremendous" and "unparalleled" growth in installed utility-scale solar capacity in DEC's and DEP's service territories.[3] NCSEA Witness Johnson also agreed that North Carolina has experienced "significant" growth in solar power production and highlighted that solar growth in North Carolina is occurring at a "substantial and more rapid" pace than in neighboring states.[4]

Q. DID THE PUBLIC STAFF CONCLUDE THAT THE RAPID GROWTH IN PURPA SOLAR GENERATION HAS IMPACTED AND WILL CONTINUE TO IMPACT OUR CUSTOMERS AND OPERATIONS?

A. Yes. As recognized by Public Staff Witnesses Hinton and Dustin R. Metz, the tremendous growth in "must take" energy from PURPA solar QFs in North Carolina has both: (i) increased the risk of potential overpayments by our customers; and (ii) posed challenges to meeting the Companies' obligation to provide safe, reliable, and economic service to customers, including complying with mandatory NERC BAL Standards.[5] As a result, the Public Staff agreed with several of the Companies' recommendations to evolve the Commission's long-held PURPA policies in light of the current economic and regulatory conditions.

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3 Public Staff Hinton Testimony, at 5, 7.

4 NCSEA Johnson Testimony, at 33, 34,

5 Public Staff Hinton Testimony, at 7; Public Staff Metz Testimony, at 6.

Q. DO ANY OTHER INTERVENORS SUPPORT EVOLVING THE COMMISSION'S LONG-STANDING PURPA POLICIES TO MEET THE RISKS AND CHALLENGES POSED BY THE RECENT SURGE IN QF SOLAR FACILITIES IN NORTH CAROLINA?

A. Notably, the North Carolina Electric Membership Corporation ("NCEMC"), a wholesale customer of the Companies that does not typically intervene in the Commission's biennial avoided cost proceedings, filed Comments in this proceeding. NCEMC is a generation and transmission cooperative responsible for the full or partial power supply requirements of 25 distribution cooperatives throughout North Carolina. According to its Comments, NCEMC serves more than 850,000 farms, homes, and businesses, and it purchases significant amounts of power from the Utilities. Because of these purchase arrangements with the Utilities, and the potential for "pass-through" to NCEMC of certain energy and capacity costs to comply with PURPA or to integrate QFs, NCEMC is concerned about the "undeniable" cost increases resulting from the influx of solar in North Carolina.[6] NCEMC also reported that it depends on the Utilities' bulk power services, especially their transmission services, to serve its customers in North Carolina. Thus, NCEMC also expressed concern that over-generation events in the DEP BA would potentially present significant reliability challenges, resulting in congestion at a transmission level that would threaten system reliability and

6 NCEMC Comments, at 7.

NCEMC's ability to reliably serve its customers' energy needs.[7] For these reasons, NCEMC urged the Commission to evolve its existing PURPA policies to avoid potentially allowing these increased costs and system impacts to continue.

Q. DO NCSEA AND SACE SUPPORT THE COMPANIES' PROPOSALS TO EVOLVE THE COMMISSION'S PURPA POLICIES TO ADDRESS THE CURRENT ECONOMIC AND REGULATORY CIRCUMSTANCES RESULTING FROM THE SURGE OF QF SOLAR FACILITIES?

A. No. While NCSEA Witness Johnson recognizes the recent, unprecedented solar QF development in North Carolina and acknowledges that North Carolina's PURPA experience is an outlier when compared to most other states, his testimony on behalf of NCSEA opposes nearly every aspect of the Companies' proposals to evolve the Commission's PURPA standard offer policies. SACE Witness Vitolo does not even mention the State's recent surge of solar QF development in his testimony. Instead, his testimony tends to urge the Commission to simply maintain the status quo by re-stating its previous avoided cost conclusions from the 2014 avoided cost proceeding.

7 NCEMC Comments, at 8.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ASSERTION THAT THE COMPANIES' PROPOSALS TO EVOLVE THE COMMISSION'S PURPA POLICIES ARE INTENDED TO "SLAM ON THE BRAKES" WITH RESPECT TO SOLAR DEVELOPMENT IN THIS STATE?

A. I do not agree at all. The Companies' proposed modifications to the standard offer in this proceeding are not intended to stop solar development in North Carolina, but instead are intended to be a necessary first step to continuing solar development in this State in a smarter, more sustainable way. Other longer-term steps may include the Companies' proposal to collaborate with interested parties to develop a competitive solicitation process to provide for sustainable growth in new solar resources, continuing to participate in the Interconnection Stakeholder discussions, and addressing additional PURPA policies for larger QFs in the near future.

The current PURPA policies, however, have resulted in uncoordinated and unrestrained growth of PURPA solar facilities in North Carolina in an unmanageable way. I discuss our specific proposed modifications in more detail later in my testimony, but I note here that the proposed modifications are specifically intended to address the two current and critical issues with respect to the continued surge in solar QFs that are 5 MWs and less: (i) the increased risk of overpayments for PURPA solar power by our customers; and (ii) the increasing challenges to reliably planning and operating the Companies' systems as additional QF solar is installed. As discussed in the

Companies' Joint Initial Statement, DEC and DEP have long-range PPAs with Commission-set avoided costs ranging from $55 to $85 per MWh, while the Companies' current avoided costs are closer to $35 per MWh. This disparity has resulted in our customers bearing an estimated $1 billion overpayment for PURPA power for the remaining lives of the applicable PPAs, which is the next 12-15 years. With respect to our systems' operations, PURPA requires the Companies to interconnect and purchase from QFs. The purchase is "must take," and the Companies currently have no ability to dispatch and only limited emergency rights to curtail QF generators under the PURPA construct. As Witness Holeman explains, this inhibits the Companies' ability to maximize the reliable and economic operation of the energy grid. In sum, as described in my direct testimony, the Commission has previously evolved its PURPA policies over the last 35 years in response to changing economic and regulatory circumstances. The Companies respectfully request that the Commission again exercise the broad discretion afforded to States under PURPA to assure the Companies' avoided cost rates are just and reasonable to our customers and the State's PURPA policies serve the public interest in light of the current economic and regulatory circumstances existing in North Carolina today.

Q. DOESN'T THE COMMISSION HAVE AN OBLIGATION TO ENCOURAGE QF DEVELOPMENT THROUGH PURPA AS ADVOCATED BY NCSEA WITNESS JOHNSON?

A. I agree that PURPA is intended to encourage QF development, but not at any and all costs. QF advocates often stress that the purpose of PURPA is to encourage development of QFs, as Witness Johnson has done in this proceeding, while downplaying PURPA's specific directive that the tariffs under which QFs sell power must also be "just and reasonable to the electric consumers of [the purchasing utility] and in the public interest."[8] Furthermore, PURPA is not intended as a means to make any and all QFs viable. Instead, as this Commission has previously recognized, PURPA specifically requires the Commission *to balance* the goal of encouraging QF development and the interests of the State's electric customers when it implements PURPA.[9] Moreover, PURPA is not intended to be an unlimited source of subsidy for QFs. Contrary to Witness Johnson's assertion, the Commission is not expected to treat avoided costs as a pricing "*floor*" for QF purchases.[10] Congress has made clear that rates paid to QFs under PURPA must be capped at the utility's respective avoided cost, and be just and reasonable to the utility's customers.[11] Thus, avoided costs provisions should

8 16 USC § 824a-3(b)(1).

9 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 11, Docket No. E-100, Sub 136 (Feb. 21, 2014).

10 NCSEA Johnson Testimony, at 21.

11 16 USC § 824a-3(b), (d).

operate as *a ceiling*, not an open-ended entitlement for QFs. As the U.S. Supreme Court has found, public service commissions implementing PURPA may even authorize payments to QFs that are below full avoided cost if the lower rate is still sufficient to encourage QF development.[12] The Companies are not suggesting that the Commission adopt rates below full avoided costs, however, this permitted result underscores Congress' intent and the legal limitations of PURPA. PURPA supports QF developers by ensuring they can interconnect and sell all of their output to utilities, but only if they can do so efficiently, i.e., at no incremental cost to the utility's customers.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S OPINION THAT THE IDENTIFIED OPERATIONAL RISKS AND CHALLENGES DO NOT NECESSITATE THE COMPANIES' PROPOSED MODIFICATIONS IN THE COMMISSION'S PURPA POLICIES FOR THE STANDARD OFFER?

A. No, I do not. Although Witness Johnson appears to at least acknowledge the operational issues caused by the influx of intermittent and unconstrained solar energy confronting our system operators, he effectively dismisses these challenges as mere "growing pains" in integrating more solar energy in North Carolina, and he rejects the Companies' proposed solutions.[13] As discussed above and further described by Witnesses Yates and Holeman, it is important

12 *Am. Paper Inst. v. Am. Electric Power Serv. Corp*., 461 U.S. 402, 416 (1983) ("[A]ny state regulatory authority . . . may apply to [FERC} for a waiver of the rule. A waiver may be granted if the applicant demonstrates that a full-avoided-cost rate is unnecessary to encourage cogeneration and small power production 18 C.F.R. Sec. 292.403.").

13 NCSEA Johnson Testimony, at 209.

for the Commission to understand how the State's implementation of PURPA will impact the rates customers pay and the way the Companies manage and operate their generating fleets and transmission and distribution systems for decades to come.

III. REDUCING THE ELIGIBILITY CAP FOR STANDARD RATES, TERMS, AND CONDITIONS TO 1 MW WILL MAKE AVOIDED COST RATES MORE ACCURATE AND WILL NOT BURDEN THE PARTIES OR THE COMMISSION

Q. PLEASE EXPLAIN THE PURPOSE OF THE COMPANIES' PROPOSAL TO LOWER THE SCHEDULE PP STANDARD OFFER TARIFF ELIGIBILITY CAP FROM 5 MW TO 1 MW.

A. As stated in my direct testimony, the purpose of this proposal is to ensure that the avoided cost rates offered to larger "utility-scale" QFs above 1 MW are based on a more precise and timely assessment of the costs that a particular QF allows the Companies to avoid. By lowering the eligibility threshold to 1 MW, the Commission will balance two competing objectives under PURPA. First, it enables the Companies to negotiate more precise avoided cost rates with more solar QFs, based on the most up-to-date data and taking the specific characteristics of the particular QF into consideration to mitigate the risk of customer over-payment for QF power. At the same time, however, this proposal also ensures that 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 avoided cost rates with the Utilities. Notably, a standard offer capped at 1 MW still "significantly encourages" small QF development over and above the standard offer requirements set forth in the Federal Energy Regulatory Commission's ("FERC") regulations.[14]

The record in this proceeding shows that the 5 MW threshold has served its intended purpose and has significantly encouraged QF development in North Carolina. As I generally described in my direct testimony, and as confirmed in the direct testimony of Public Staff Witness Hinton, more than 750 QF generators at or just below 5 MWs have obtained certificates of public convenience and necessity ("CPCN") in North Carolina since 2013, the vast majority of which are solar QFs desiring to sell power to the Utilities under PURPA.[15] Based on this unprecedented level of utility-scale solar, continued significant encouragement of solar development through this 5 MW threshold will cause unjust and unreasonable long-term PURPA purchase obligations on the Companies' customers. Transitioning to 1 MW at this time is necessary and reflects the current economic and regulatory circumstances.

Q. IS DECREASING THE MAXIMUM CAPACITY ELIGIBLE FOR STANDARD TARIFF RATES CONSISTENT WITH PURPA?

A. Yes. Neither NCSEA Witness Johnson nor SACE Witness Vitolo contend that the Companies' proposal violates PURPA or FERC's regulations implementing PURPA, which only require that standard contracts be offered

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14 18 C.F.R. 292.304(c)(2); *Order No. 69, FERC Stats. & Regs.*, *Preambles 1977-1981* P30,128 at 30,865. ("Order No. 69") (In approving subsection (c)(2) providing the option for standard offer purchase rates above 100 kW, FERC explained that "establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases.").

15 Public Staff Hinton Testimony, at 41 (aggregating approved CPCNs for 4 to 5 MW QFs from 2013 to 2016 equates to 753 new generators being certificated during this period.)

to QFs of 100 kW or less.[16] Moreover, as discussed in my direct testimony, the Commission has modified the eligibility threshold in the past, based on the economic and regulatory circumstances present at the time.[17] When the Commission first implemented the 5 MW eligibility threshold in 1985, the small power production industry was in its infancy in North Carolina. As discussed above, this significant encouragement is no longer required or appropriate.

Q. DID THE OTHER PARTIES FILING TESTIMONY IN THIS DOCKET AGREE WITH THE COMPANIES' PROPOSAL TO REDUCE THE ELIGIBILITY THRESHOLD?

A. The Public Staff agreed with both the Companies' and DNCP's proposals to adjust the eligibility threshold to 1 MW, based on the current economic and regulatory circumstances. NCSEA Witness Harkrader opposed the adjustment. NCSEA Witness Johnson, however, recommended only a slight adjustment to the threshold, and SACE Witness Vitolo recommended that the Commission simply maintain the status quo.

Q. WHAT WAS NCSEA WITNESS JOHNSON'S RECOMMENDATION?

A. Witness Johnson recommended adjusting the threshold from 5 MWs downward "perhaps to 3.75 or 4 MW" on the grounds that the Commission should be cautious and see how the market reacts before adjusting the

16 18 C.F.R. 292.304(c).

17 DEC-DEP Bowman Direct Testimony, at 10-13, 34.

threshold further or, alternatively, simply postponing this decision for another two years.[18]

Q. WHY IS A 1 MW ELIGIBILITY THRESHOLD MORE APPROPRIATE THAN A 3.75 MW OR 4 MW ELIGIBILITY THRESHOLD, AS WITNESS JOHNSON RECOMMENDS?

A. In the Companies' experience, a 1 MW eligibility threshold is 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. Furthermore, as discussed by Witness Freeman, the Companies' experience has been that solar projects at or below 1 MW are more likely to pass the Section 3 Fast Track process, which means that both the PPA and interconnection agreement could be obtained in a more standardized and streamlined fashion. Therefore, the Companies do not find Witness Johnson's limited support for this proposal credible and anticipate that this proposal would be more likely to perpetuate the unconstrained development of large numbers of QFs by well-capitalized, sophisticated solar developers under the Companies' standard offer tariff and PPAs, which is no longer in the public interest and would impose unjust and unreasonable costs on our customers.

18 NCSEA Johnson Testimony, at 219.

Q. PLEASE RESPOND IN GENERAL TO WITNESS VITOLO'S RECOMMENDATIONS TO MAINTAIN THE STATUS QUO WITH RESPECT TO THE ELIGIBILITY THRESHOLD.

A. Witness Vitolo makes his recommendations without reference to, or acknowledgement of, the current economic and regulatory circumstances resulting from the tremendous surge of solar QFs in North Carolina. These current economic and regulatory conditions, however, drive the Companies' proposals to modify the standard offer. As Public Staff Witness Hinton provides in his direct testimony, at this time, a 1 MW threshold better reflects current conditions and better protects the ratepayers from the risk of overpayment.[19]

Q. PLEASE RESPOND TO WITNESS VITOLO'S ASSERTION THAT ADJUSTING THE ELIGIBILITY THRESHOLD TO 1 MW WILL CAUSE SOLAR QFs TO FOREGO ECONOMIES OF SCALE AND BUILD SMALLER PROJECTS TO AVOID THE RISKS AND COSTS OF NEGOTIATION.

A. Witness Vitolo urges the Commission to retain the 5 MW threshold because it will allow QF developers to retain the economies of scale associated with developing a larger (5 MW) QF project and avoid the risk and cost of negotiations.[20] This will result in "lower costs overall," according to Witness Vitolo. I note, however, that the lower costs of QF development highlighted

19 Public Staff Hinton Testimony, at 44.

20 SACE Vitolo Testimony, at 9.

by Witness Vitolo refer to lower costs for QF developers and not our customers. Our customers do not benefit from these cost savings, because the rates paid to QFs (and borne by the Companies' customers) are based on the Companies' avoided costs, and not the cost incurred by the developers to construct the QF facility.

I would also propose that the Commission view Witness Vitolo's argument in the inverse as actually supporting the Companies' proposed reduction in the standard offer to differentiate between relatively small projects up to 1 MW and utility-scale developer-sponsored solar projects, which have, to date, been developed at 5 MWs to avail themselves of the standard offer. As I explained in my direct testimony, "disaggregating" potentially larger and more cost efficient utility-scale solar projects to meet the 5 MW standard contract threshold has caused numerous challenges, including the ongoing challenge of managing the interconnection of these generators to rural circuits on the Companies' increasingly saturated distribution systems as well as paying stale avoided cost rates to numerous larger QFs up to 5 MWs during a period of declining energy costs.[21] Eliminating the incentive to arbitrarily develop 5 MW solar projects may, in fact, improve economies of scale if solar developers transition to developing larger projects.

21 DEC-DEP Bowman Direct Testimony, at 37.

Q. HOW DO YOU RESPOND TO WITNESS VITOLO'S CONTENTION THAT THERE IS A SIGNIFICANT POWER IMBALANCE IN QFs' NEGOTIATIONS WITH UTILITIES?

A. As I stated in my direct testimony, utility-scale solar QFs are no longer being developed by small, fledgling project developers or "customer-owned QFs." Witness Vitolo does not acknowledge that the majority of utility-scale solar project developers are no longer unsophisticated, small developers. For example, my Figure 1 below demonstrates that six large power generation developers, which are participants in the energy supply industry across the United States, account for more than 65% of the standard offer projects in the Companies' combined interconnection queues between 1 MW and 5 MWs.

Figure 1

Upstream Project Developer Name	Projects under Development in DEP	Projects under Development in DEC	Total Projects under Development in Duke Interconnection Queues
Cypress Creek Renewables (includes legacy FLS Energy)	59	24	83
Strata Solar	53	8	61
ESA Renewables	25	15	40
Sunlight Partners	32	1	33
Headwaters Solar	17	13	30
GreenGo Energy (formerly NARENCO)	22	5	27
Total Top 6 Developers	**208**	**66**	**272**

Q. DO YOU AGREE THAT ADJUSTING THE ELIGIBILITY THRESHOLD WILL RESULT IN PROTRACTED AND COSTLY NEGOTIATIONS BETWEEN QFs AND THE UTILITIES?

A. No, I do not. As I stated in my direct testimony, the Companies have significant experience negotiating PPAs with solar QF developers, as developers are increasingly planning and developing larger QF projects up to 80 MWs in size over the past few years.[22] The Companies have developed more standardized PPA terms and conditions for larger QFs, effectively streamlining the process. The use of standardized terms means that negotiations do not have to start from scratch and ensures that QFs receive consistent treatment. Additionally, producing updated monthly avoided cost calculations for these negotiated PPAs has become routine. As Witness Vitolo states, the Companies require 25 hours, or just three business days, of staff effort to develop an updated avoided cost calculation and to negotiate an uncontested PPA.[23]

Q. HOW DO YOU RESPOND TO WITNESS VITOLO'S ASSERTION THAT NEGOTIATIONS WITH THE COMPANIES FOR A PPA CAN TAKE MONTHS?

A. Two parties are involved in every negotiation, and delays are not always caused by the Companies. Witness Vitolo supports his assertion by referring to a data request response that the Companies provided to SACE, asking for

22 DEC-DEP Bowman Direct Testimony, at 43.

23 SACE Vitolo Testimony, at 8.

the Companies to identify the dates of the legally enforceable obligations ("LEOs") and the execution dates for negotiated PPAs for QFs larger than 5 MWs. The request did not reflect, however, that under the Notice of Commitment form approved by the Commission in Docket No. E-100, Sub 140, "large" QFs have up to six months to execute a PPA after the Companies submit it to the QF for signature.[24] My understanding is that large QFs sometimes wait until that six months is close to expiring to execute a PPA with the Companies.

I would also emphasize, as noted by Public Staff Witness Hinton,[25] that the Companies intend to further streamline and standardize the PPA negotiation process to reduce the transaction costs and the time for negotiating PPAs with QFs. In Witness Freeman's direct testimony, the Companies have proposed contracting procedures that will foster transparency and efficiency in negotiating contracts with QFs, providing clear steps that the QF and utility will follow throughout the negotiation process towards execution of a PPA. Witness Freeman is now providing draft contracting procedures for the Commission's review and approval in his rebuttal testimony. The Companies believe that these procedures can be implemented quickly – with appropriate input from Public Staff and other interested parties – after the Commission issues a final order in this proceeding.

24 Notice of Commitment to Sell the Output of a Qualifying Facility to Duke Energy Carolinas, LLC, or Duke Energy Progress, LLC ¶ 6 (c).

25 Public Staff Hinton Testimony, at 46, 47.

Q. WHAT ADDITIONAL DETAILS CAN YOU PROVIDE TO THE COMMISSION WITH RESPECT TO CALCULATING AVOIDED COST RATES FOR LARGE QFs THAT ARE NOT ELIGIBLE FOR THE STANDARD OFFER RATES?

A. The Companies intend to continue to follow FERC and Commission guidance in negotiating PPAs with large QFs. FERC's regulations specifically provide that the following factors can be considered 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.[26] In addition, the Commission has directed the Utilities to negotiate with QFs in good faith and has listed specific issues 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;

26 18 C.F.R. 292.304(e).

- Capacity credits that reflect the need (or lack of need) for additional capacity at the time of 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 qualifying facilities;
- 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.[27]

In addition to this long-established guidance, the Commission has also more recently addressed the Companies' requirements when negotiating with large QFs in its *Order on Clarification* in Docket No. E-100, Sub 140 ("*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."[28] By taking into account the factors listed in the FERC's regulations and prior Commission orders, the Companies can more precisely tailor their avoided cost rates for QFs greater than 1 MW to 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.

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

28 *Order on Clarification*, at 3, Docket No. E-100, Sub 140 (March 6, 2015).

Q. DO THE COMPANIES INTEND TO INCLUDE THE COSTS OF ANCILLARY GENERATION SERVICES OR OTHER SOLAR INTEGRATION COSTS IN THEIR CALCULATIONS OF AVOIDED COST RATES FOR QFs THAT ARE NOT ELIGIBLE FOR THE STANDARD OFFERS?

A. The Companies believe that inclusion of these costs to calculate avoided cost rates for use in bilateral negotiations with QFs is appropriate and consistent with the FERC and Commission decisions discussed above. As part of bilateral negotiations with the Companies, the QFs may always request to review the inputs to DEC's or DEP's calculated rates; if a QF disagrees with the Companies' calculation of its avoided costs, the Commission has long provided that the parties are to negotiate in good faith and a QF may always file a complaint or petition the Commission to arbitrate the matter.

Q. WOULD THE COMPANIES OPPOSE THE COMMISSION ESTABLISHING A NEW PROCEEDING TO EVALUATE THE MANNER IN WHICH THE COMPANIES DETERMINE THEIR AVOIDED COSTS FOR LARGE QFs?

A. As discussed above, both FERC's regulations and prior Commission Orders have provided relatively clear guidance for the Companies to follow in developing their avoided cost rates for larger negotiated QFs. At this time, the Companies do not anticipate such a proceeding is required, as the Companies agree to identify the inputs to their avoided cost calculations for QFs as part of the negotiation process. However, if future arbitrations or complaints arise or the Commission otherwise determines that an additional formal or informal proceeding would be beneficial to resolve concerns regarding how the Companies calculate their avoided cost rates for large QFs, the Companies do not object.

IV. <u>THE COMPANIES' PROPOSED LONG-TERM LEVELIZED SCHEDULE PP RATE STRUCTURE PROTECTS CUSTOMERS FROM THE GROWING RISKS OF OVERPAYMENTS</u>

Q. PLEASE REINTRODUCE THE COMPANIES' PROPOSAL TO MODIFY THE SCHEDULE PP STANDARD OFFER CONTRACT TERM.

A. As discussed in the Companies' Joint Initial Statement and in my pre-filed direct testimony, the Companies' proposed Schedule PP has been modified to a single 10-year long-term avoided cost standard contract with fixed capacity rates, but with energy rates to be updated every two years as part of the Commission's biennial review of the Companies' avoided costs. As I, along with Witness Snider, explained in direct testimony, this proposal has been designed in light of current economic and regulatory circumstances to pay small QFs eligible for the standard offer a levelized capacity value over the full 10-year term, while mitigating the significant forecast risk of over- or under-projecting long-term commodity prices. Specifically, the biennial adjustment of the energy component will more closely align future avoided energy cost payments with the Companies' actual avoided cost of energy, whether that energy cost is increasing or decreasing, and is designed to protect customers from over-paying for avoided energy in future years where fuel commodity forecasts are not as certain.

Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES' PROPOSED REDUCTION OF THE SCHEDULE PP TERM TO 10 YEARS?

A. Yes. Public Staff Witness Hinton discusses this issue at pages 52-57 of his testimony and supports the Companies' proposed reduction of the Schedule PP term to 10 years, explaining "Due to the continued rapid pace of QF development in North Carolina, the Public Staff believes it is appropriate at this time for the Commission to consider a shorter-term structure for avoided cost rates."[29] Witness Hinton supports this recommendation by explaining that reducing the contract term will "serve to reduce the risk borne by ratepayers for overpayments over a longer term."[30] Indeed, Witness Hinton highlights the growing overpayment risk to customers multiple times throughout his testimony, emphasizing the "sheer volume of QF projects currently being developed in North Carolina from which the utilities are obligated to purchase the energy and capacity at avoided cost rates."[31]

Q. DO OTHER INTERVENORS SUPPORT THE COMPANIES' PROPOSED REDUCTION OF THE SCHEDULE PP TERM TO 10 YEARS?

A. NCSEA Witnesses Harkrader and Strunk, Cypress Creek Witness McConnell, and SACE Witness Vitolo all oppose the proposed reduction in the standard offer term to 10 years preferring the status quo be maintained. These

29 Public Staff Hinton Testimony, at 56.

30 *Id.*

31 Public Staff Hinton Testimony, at 7.

witnesses all generally allege that financing and development of QF projects will be more challenging under the Companies' proposal to reduce the standard offer term to 10 years. SACE Witness Vitolo also argues that the Commission should consider mandating the Companies to offer solar QFs fixed contracts of 20/25 years to match the recovery period of the respective utility's own solar PV assets.[32]

Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES' PROPOSAL TO RESET THE AVOIDED ENERGY RATE EVERY TWO YEARS IN FUTURE COMMISSION AVOIDED COST PROCEEDINGS?

A. No. Public Staff Witness Hinton expresses concern that "resetting energy rates every two years for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing difficult or impossible."[33]

Q. DO OTHER PARTIES SUPPORT THE COMPANIES' PROPOSAL TO RESET THE AVOIDED ENERGY RATE EVERY TWO YEARS IN FUTURE COMMISSION AVOIDED COST PROCEEDINGS?

A. Consistent with their opposition to reducing the standard offer to a 10-year term, NCSEA, SACE, and Cypress Creek also oppose the Companies' proposal to biennially reset the avoided energy rates in future Commission avoided cost proceedings.

32 SACE Vitolo Testimony, at 17.

33 Public Staff Hinton Testimony, at 58, 60.

NCSEA Witness Johnson raises concerns that QFs' revenue stream will become "highly unpredictable" and will depend not only on "the future course of volatile fuel prices" but also on "the outcome of litigated proceedings every two years."[34] NCSEA Witness Strunk and Cypress Creek Witness McConnell present similar views arguing that biennially resetting avoided energy rates every two years does not provide QF developers a reasonable opportunity to attract capital from potential investors. Witness Strunk suggests that "the proposed two-year energy price reset leads to a situation where lenders and equity investors will only be able to count on two (2) years of known energy revenues" such that "[a]ll energy revenues after the second year will be regarded by lenders and equity sponsors as risky and will be discounted accordingly."[35] Witness McConnell similarly argues that "[f]inancing parties would view a ten-year contract with a two year readjustment no more favorably than they would a two-year contract" which he alleges is not currently financeable.[36] Finally, SACE Witness Vitolo alleges that the Companies have not evaluated potential adverse impacts on the ability of solar QFs to obtain financing with energy rates recalculated every two years.

34 NCSEA Johnson Testimony, at 158.

35 NCSEA Strunk Testimony, at 15.

36 Cypress Creek McConnell Testimony, at 7.

Q. PLEASE RESPOND.

A. As discussed extensively in my direct testimony and the Companies' Joint Initial Statement, the combination of surging solar QF development and the recent deviation in market-based commodity costs compared to prior forecasts have resulted in customers being obligated for significant long-term over-payments compared to the Companies' current forecast of avoided costs. Witness Snider highlighted in our direct case that this overpayment could be as much as $1.0 billion over the term of existing PPAs for installed QFs, even before taking into account the approximately 1,100 MWs of proposed solar QFs in development that are eligible for the Commission's previous 2014 Sub 140 or 2012 Sub 136 standard offer avoided cost rates. Continuing existing policy or increasing the standard offer term, as proposed by SACE Witness Vitolo, would exacerbate the already significant overpayment risk for our customers in the future, which is no longer compatible with PURPA's mandate that avoided cost rates and policies shall be just and reasonable to utility customers and in the public interest.[37]

The Companies appreciate the Public Staff's recognition that reducing the standard offer term to 10 years, especially when combined with other modifications supported by the Public Staff, is reasonable and will serve to mitigate some overpayment risk in light of the current evolving economic and regulatory circumstances of surging solar QF development in North Carolina. However, the Companies continue to be concerned that long-term

37 16 U.S.C. §824a-3(b)(1).

overpayment risk associated with forecasted commodity pricing may result in payments in excess of the Company's future incremental cost of alternative energy, which is inconsistent with PURPA.[38] Mandating that customers be assigned this risk is simply not just and reasonable to customers and in the public interest based upon recent levels of QF development.

Q. HOW DO THE COMPANIES RESPOND TO ARGUMENTS THAT THEY DID NOT EVALUATE THE FINANCEABILITY OF THE PROPOSED STANDARD OFFER FOR SMALL SOLAR QFs?

A. The Companies 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 in order to determine whether to develop a project. As discussed in my prefiled direct testimony, the fact that North Carolina has experienced 60% of installed PURPA-driven solar generation nationally is clear evidence that continuing the status quo PURPA policies in North Carolina can result in significant additional QF solar development. Based upon current economic and regulatory circumstances, however, the Companies designed the Schedule PP avoided cost standard offer to provide reasonable encouragement of small QFs through a 10-year fixed avoided capacity rate while mitigating the risk of potential overpayment associated with long-term commodity forecasts. In presenting this proposal to the Commission, the Companies' focus was on mitigating the recently-experienced long-term overpayment risks to customers. Biennially resetting

38 16 U.S.C. §824a-3(d).

avoided energy cost rates based upon future avoided energy rates approved by the Commission every two years is a just and reasonable mechanism to accomplish this objective.

Further, as highlighted in my direct testimony and recognized by Public Staff Witness Hinton, the Companies evaluated the standard offer rates approved in other southeastern states, as well as reviewed how other states such as Idaho have responded to significant PURPA development in those jurisdictions.[39] Notably, only NCSEA Witness Johnson commented on how PURPA is being implemented across the country and throughout the southeast, effectively recognizing that North Carolina's implementation of PURPA has significantly encouraged unprecedented QF development compared to other states.[40] The other Intervenor witnesses have largely focused only on maintaining status quo policies in North Carolina.

Finally, I also note that FERC's PURPA regulations have long provided a method through 18 C.F.R. 292.302 for QF investors to evaluate the utility's longer-term need for capacity and forecasted cost of energy. This section of FERC's regulations requires the utilities to biennially file forecasted electric utility system cost data for both energy and capacity with the Commission. As explained by FERC in Order No. 69, this data can then be

39 Public Staff Hinton Testimony, at 58.

40 NCSEA Johnson Testimony, at 25-26.

used by QFs and their investors in evaluating the utility's future avoided costs.[41]

Q. DOES A STANDARD OFFER THAT INCLUDES BIENNIALLY RESETTING AVOIDED ENERGY RATES EVERY TWO YEARS PROVIDE QF DEVELOPERS A REASONABLE OPPORTUNITY TO ATTRACT CAPITAL FROM POTENTIAL INVESTORS?

A. In my current role at Duke Energy, I have not had occasion to become an expert on the contract terms and conditions that the financial community would deem "reasonable" or that are otherwise minimally necessary to allow for attraction of the capital needed to encourage QF development. My general understanding is that numerous factors 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, and the risk of the investment, amongst others, all come into play in determining whether an investment can attract debt and/or equity capital. Witness Hinton's comments that smaller QFs eligible for the standard offer may need greater certainty with regard to securing capital and return on investment than larger QFs seems reasonable.[42] I would also highlight that, unlike the cost-of-service-based rates of electric utilities like DEC and DEP, PURPA largely exempts QFs from state regulatory authority oversight of their rates and business operations so that neither the Companies, the Public Staff,

41 *Order No. 69*, *supra* note 14, at 19 (discussing 18 C.F.R. 292.302).

42 Public Staff Hinton Testimony, at 59-60.

nor the Commission has any clear insights into a QF developer's business or the level of profit deemed "reasonable" to attract equity capital.[43]

I am, however, aware that FERC recently issued a declaratory Order[44] in response to an enforcement petition by 26 solar QFs ("Windham Solar QFs") presenting its view (but not taking enforcement action) that the Connecticut Public Utility Regulatory Authority's ("PURA") implementation of PURPA was inconsistent with FERC's regulations because the purchasing utility's approved avoided cost tariff offered QFs only the ISO-New England real-time energy price. The Windham Solar QFs argued that offering this single real-time pricing energy-only rate was inconsistent with the QFs' right under 18 C.F.R. 292.304(d)(2) of FERC's regulations to commit to deliver power pursuant to a legally enforceable obligation based upon a forecasted avoided cost rate. In determining that the Windham Solar QFs had a right under PURPA to elect to sell power pursuant to a legally enforceable obligation at a forecasted avoided cost rate, the *Windham Solar Order* made three findings (only one of which is cited by intervenors in this case),

- FERC's 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 factors which include, among others, the availability of capacity, the QF's dispatchability,

43 *See* 18 C.F.R. § 292.601 (2017) (exempting QFs under 30 MW from most sections of the Federal Power Act); 18 C.F.R. § 292.602 (exempting QFs under 30 MW from the Public Utility Holding Company Act of 2005, 42 U.S.C. 16,451-63 and state laws and regulations on electric utility rates and financial and organizational regulation of electric utilities).

44 *Windham Solar, LLC*, 157 FERC ¶ 61,134 (2016) ("Windham Solar Order").

the QF's reliability, and the value of the QF's energy and capacity. (P. 6);

- QFs may be able to provide capacity to utilities in restructured power markets, such as ISO-New England, including the possibility of the utility offering QF capacity into the market. (P. 7);
- 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 legally enforceable obligation should be "long enough to allow QFs reasonable opportunities to attract capital from potential investors." However, FERC reiterated that its regulations do not specify a particular number of years for such legally enforceable obligations, meaning that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing State Commission. (P. 8, Fn. 13).

Q. SHOULD THE *WINDHAM SOLAR ORDER* MATERIALLY CHANGE THE COMMISSION'S ANALYSIS OF THE COMPANIES' PROPOSED STANDARD AVOIDED COST RATES OFFERED IN NORTH CAROLINA UNDER PURPA?

A. No, it should not. The Commission's mandate under PURPA continues to be focused on ensuring that DEC's and DEP's avoided cost rates are just and reasonable to consumers and in the public interest, not discriminatory against QFs, and do not exceed the cost of the energy the utility would have incurred through self-generation or otherwise, but for the purchase from the QF.[45] Notably, this decision arose based upon Connecticut's implementation of PURPA within the organized ISO-New England wholesale power market, where that State's purchasing utilities offered only a real-time energy avoided cost rate and did not recognize that QFs could meet future capacity needs (or offer to pay the QF for capacity). In contrast, the Companies' Schedule PP rate is designed to pay QFs for capacity during the 10-year Schedule PP term where DEC's or DEP's biennial IRP identifies that a future capacity need can be avoided by QF power. Specific to avoided energy value, the *Windham Solar Order* does not suggest that the ISO-New England market-based value of energy is not an appropriate methodology to establish the future avoided energy value of QF power in Connecticut.

The Companies are also aware of only one other jurisdiction outside of an organized wholesale market that has considered FERC's recent guidance in the *Windham Solar Order* in setting forecasted avoided cost rates to implement PURPA. In early March, the Alabama Public Service Commission approved Alabama Power Company's ("Alabama Power") standard offer rate for QFs with a design capacity above 100 kW, which offers Alabama Power's forecasted avoided 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 the

45 *See* 16 U.S.C. §§ 824a-3(b), (d).

Company."[46] The Alabama PSC held this rate structure continued to be consistent with PURPA and the FERC's prior guidance that a "long-term contract" in the context of PURPA is "one year or longer."[47]

In light of the distinguishable facts and circumstance underlying the Connecticut PURA's implementation of PURPA in ISO-New England as well as limited regulatory developments outside of an organized wholesale market since the *Windham Solar Order*, the Companies do not view FERC's guidance as materially affecting the Commission's analysis of whether the Companies' proposal is a reasonable implementation of DEC's and DEP's obligation to purchase from QFs under PURPA.

Q. DO THE COMPANIES SUPPORT THE PUBLIC STAFF'S "ALTERNATIVE PROPOSALS" TO MITIGATE FUTURE AVOIDED ENERGY FORECAST RISK FOR CUSTOMERS WHILE PROVIDING ADDITIONAL CERTAINTY FOR SMALL STANDARD OFFER QFs?

A. Potentially. While Witness Hinton does not support the Companies' proposal to biennially reset avoided energy cost rates for small QFs, he does signal that the Public Staff would be open to "other options" to mitigate the potential overpayment risk for customers such as "linking available energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment that energy rates could vary from some indicative

46 *Alabama Power Company, Petition: For approval of Rate CPE -- Contract for Purchased Energy*, Docket No. U-5213 (March 7, 2017).

47 *Id. Citing See New PURPA Section 210(m) Regulations Applicable to Small Power Production Facilities and Cogeneration Facilities, Order No. 688-A*, 119 FERC P 61,305, at P 27 & n.17 (2007).

pricing."[48] NCSEA Witness Johnson similarly seems to support Public Staff Witness Hinton's alternative concept of linking the future avoided energy rate to "a published fuel price index," further agreeing with Witness Snider that this approach is "inherently less risky and more predictable [than the outcome of biennial litigation] and is typical practice in the industry."[49]

The Companies have not had sufficient opportunity to fully analyze these alternative proposals, but believe there is merit in evaluating whether linking avoided energy rates to a publicly available composite fuel index could mitigate future energy commodity cost risk for customers while also providing additional certainty to small QFs and their investors. Such proposals may also be reasonable for larger negotiated QF agreements to the extent a fuel index-based contract structure could mitigate the inherent inaccuracy in long-term commodity price forecasts. The Companies plan to evaluate these potential alternative proposals for small QFs between now and the next biennial avoided cost proceeding. During this period, the Companies may also gain additional experience as larger QFs seek to negotiate longer contract tenors, and the Companies continue to evaluate the most appropriate rate structures that accurately values QF energy, thereby mitigating the long-term overpayment risk for customers.

48 Public Staff Hinton Testimony, at 60.

49 NCSEA Johnson Testimony, at 159.

Q. FOR PURPOSES OF THIS PROCEEDING, DO THE COMPANIES RECOMMEND IMPLEMENTING ANY "ALTERNATIVE PROPOSALS" TO MITIGATE FUTURE AVOIDED ENERGY FORECAST RISK FOR CUSTOMERS WHILE PROVIDING ADDITIONAL CERTAINTY FOR SMALL STANDARD OFFER QFs?

A. Yes. The Companies have determined that offering small standard offer QFs the option to "fix" the 2-year avoided energy rate for the full 10-year term is an appropriate compromise in response to the testimony offered by Public Staff Witness Hinton, NCSEA Witness Strunk, and Cypress Creek Witness McConnell that small QF investors will view energy revenues in years beyond the proposed biennial update as risky and that a longer-term fixed rate (seemingly for both energy and capacity) is needed by smaller QFs in order to attract capital. As explained in my direct testimony, the biennial reset of the avoided energy component was designed to – and will remain an available option to – more closely align future avoided energy cost payments with the Companies' actual avoided cost of energy, whether that energy cost is increasing or decreasing. Selecting this option could provide QFs the potential upside benefit of increased rates if energy prices increase above the proposed 2-year rate during the 10-year contract term. However, to the extent QF developers prefer to "fix" current energy commodity prices for the full 10-year contract term, the Companies believe such an option is reasonable at this time and will protect customers from long-term forecast risk by relying on near-term energy commodity pricing underlying the 2-year avoided energy rate. The Companies propose to modify their Schedule PP tariffs within 10 business days of a Commission Order approving this additional option.

Q. DO THE COMPANIES VIEW THIS ALTERNATIVE OPTION AS A LONG-TERM SOLUTION?

A. No. As discussed above, the Companies commit to reevaluate this rate design option in the next biennial avoided cost proceeding along with the alternative options identified by the Public Staff.

Q. PLEASE RESPOND TO SACE WITNESS VITOLO'S ARGUMENT THAT THE COMMISSION DENIED A SIMILAR BIENNIAL RESET OF THE AVOIDED ENERGY RATE FOR DNCP IN THE 2010 SUB 127 PROCEEDING.

A. SACE Witness Vitolo suggests that the Commission previously addressed a similar proposal by DNCP in the 2010 avoided cost proceeding, E-100 Sub 127, and states that the Commission held that DNCP's proposed biennial reset of its energy rate was inconsistent with a QF's right to a long-term rate under FERC's *J.D. Wind* Orders.[50] As an initial matter, the Companies note that DNCP had used the biennial reset method from 1989 to 2010 prior to the Commission directing that company to transition to fixed, levelized avoided energy rates for the full contract term in the next biennial avoided cost proceeding.[51] For reasons similar to those argued by DNCP in that

50 SACE Vitolo Testimony, at 22, *citing J.D. Wind 1, LLC*, 130 FERC ¶ 61,127 (2010), *denying reh'g*, 129 FERC ¶ 61,148 (2009) (*J.D. Wind*).

51 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 127 at 9-10 (July 27, 2011) ("Sub 127 Order").

proceeding, the Companies do not believe that PURPA or FERC's regulations prohibit a biennial energy rate reset as a fixed-formula rate.[52]

Further, the Companies have developed the proposed Schedule PP rate design in light of current economic and regulatory circumstances to balance a QF's desire for long-term capacity payments with mitigating the significant energy commodity price forecast risk through a biennially re-established energy rate. Precluding such alternative formula-fixed rate options will not serve the public interest under PURPA, and will inevitably lead to shorter "fixed-rate" capacity and energy contract structures in the future. It also continues to cause North Carolina to be an outlier that significantly encourages QF development compared to other southeastern states, including "Alabama, Arkansas, Florida, Kentucky, Louisiana, Maryland, and Virginia [which] offer variable, rather than fixed long term rates" as discussed by NCSEA Witness Johnson.[53]

The Companies also note that while the Commission ultimately directed DNCP to begin forecasting a 15-year levelized rate in the next

52 *Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities*, FERC 1988-1998 Proposed Regulation Binder ¶ 32,457 at 32,171 (as quoted in *Reply Comments of Dominion North Carolina Power* at 9-10, Docket No. E-100, Sub 127 (Apr. 4, 2011)) (holding that a "fixed price contract" may include "any legally enforceable obligation wherein the rates for purchase by a utility of the power produced by a QF are established in advance of the purchase. The fixed price may be a single, uniform rate for kilowatt or kilowatt hour for all power, including a fixed formula rate, or a complex schedule of time-differentiated rates and other payments. The contracts term may range from decades to months."); *see also Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities*, Notice of Proposed Rulemaking, at 65 Docket No. RM88-6-000 (March 16, 1988) ("…a contract could provide QFs with a price floor applicable to all the power supplied to the utility, but still provide for higher variable unit prices reflecting daily or seasonal periods. The price floor would provide the revenue stream necessary for the QF to secure financial support … ***a contract could provide for a two-part price—a fixed payment for capacity and an energy price for power delivered***. The QF would be assured a minimum revenue stream based on the value of its capacity.") (emphasis added).

53 NCSEA Johnson Testimony, at 25.

biennial proceeding, the *Sub 127 Order* approved DNCP's continued use of a 2-year fixed energy rate for the Sub 127 vintage standard offer.[54] Accordingly, approval of the Companies' alternative option discussed above to fix its 2-year energy rate for purposes of this proceeding seems equally as "fixed" as DNCP's avoided cost rates in effect from 2010-2011 pursuant to the *Sub 127 Order*.

Q. FINALLY, IS SACE WITNESS VITOLO'S COMPARISON OF QF FIXED CONTRACTS AND UTILITY GENERATING ASSETS REASONABLE?

A. No. As noted above, SACE Witness Vitolo argues that the Commission should consider mandating the Companies to offer solar QFs fixed contracts of 20/25 years to match the longer recovery period of the Companies' own solar PV and other generating assets.[55] However, QF contracts are distinct from utility-owned generation in multiple ways. First, utility generating resource additions are driven by need: the Companies are not compensated by customers for energy produced from generating facilities until they establish the need for new generation through an extensive IRP process and the Commission approves a CPCN determining the facility is the least-cost resource to fill the need. In contrast, the PURPA must-purchase requirement mandates QFs must be reimbursed for selling power to the Companies whether or not the power is needed. Further, because utility load-following generating resources are dispatchable, they can be backed down when more

54 Sub 127 Order, at 10.

55 SACE Vitolo Testimony, at 17.

economic alternatives are available. Also, because utilities are not locked in to long-term fixed contracts, they can pass lower fuel and other operating costs savings to customers. In contrast, a utility 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. This inefficiency is exacerbated when long-term QF contracts are in effect. Finally, the full avoided cost rates that QFs are entitled to receive are not related to the cost of the PURPA project, whereas capital costs of utility generating assets are determined based upon cost and recovered over their depreciable useful lives. I do not anticipate that QFs would actually advocate for a longer cost recovery period based upon their cost of service; only to extend the period of guaranteed revenue (and profit) out into the future.

V. THE COMPANIES' CALCULATION OF ITS AVOIDED CAPACITY COSTS APPROPRIATELY ACCOUNTS FOR THEIR RELATIVE NEED FOR CAPACITY

Q. PLEASE EXPLAIN THE COMPANIES' PURPOSE FOR RECOMMENDING CAPACITY CREDITS THAT ACCOUNT FOR THE RELATIVE NEED FOR GENERATING CAPACITY.

A. Witness Snider will discuss this issue in more detail, but, as I noted in my pre-filed direct testimony, the Companies propose this adjustment to the avoided capacity cost calculations because our customers should not be required to pay for capacity in years in which the Companies have already built or procured sufficient capacity to serve customers, and, therefore, have no need for additional capacity. PURPA was not intended to force a utility to pay for capacity that it otherwise does not need.

Q. DO THE OTHER INTERVENORS AGREE WITH THE COMPANIES' POSITION?

A. Public Staff Witness Hinton agreed with the Companies' position on this issue, explaining "[b]y restricting the payment until the IRP has established a capacity deficiency will minimize the overpayment risk to ratepayers, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market."[56] NCSEA Witness Johnson and SACE Witness Vitolo again urge the Commission to maintain the status quo. They both cite the Commission's previous decision in the Sub 140 proceeding as support of their arguments that the Companies' avoided capacity cost rates should not be reduced when the utility shows no need to acquire QF capacity.[57]

Q. IS THE COMPANIES' PROPOSAL CONSISTENT WITH PURPA?

A. Yes. FERC has long held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity . . . [the purchase] obligation does not require a utility to pay for capacity that it does not need."[58] FERC has also expressly stated that "there is no obligation under PURPA for a utility to pay for capacity that

56 Public Staff Hinton Testimony, at 14.

57 NCSEA Johnson Testimony, at 183; SACE Vitolo Testimony, at 29-30.

58 *City of Ketchikan*, 94 FERC ¶61,293 (2001) ("*Ketchikan") citing Order No. 69, FERC Stats. & Regs., Preambles 1977-1981* P30,128 at 30,865.

would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for that capacity.[59]

More recently, in *Hydrodynamics*, FERC reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero"[60] but, based upon the specific facts of that case, held that a state rule which precluded QFs from receiving "forecasted avoided cost rates" once the utility's QF capacity purchases reached an arbitrarily set 50 MW cap was inconsistent with FERC's avoided cost regulations.[61] FERC distinguished its criticism of this state rule from the factual circumstances at issue in the prior *Ketchikan* decision because the 50 MW limit in *Hydrodynamics* was not related to the utility's actual capacity needs.[62] As Public Staff Witness Hinton notes in this proceeding, DEC's and DEP's next actual capacity needs under the Companies' respective IRPs are in 2022/2023 and 2021/2022 timeframes.[63] Accordingly, DEC and DEP should not be obligated to pay for capacity during this "capacity sufficient" period before the need arrives.

Q. PLEASE RECONCILE THE COMPANIES' PROPOSAL WITH THIS COMMISSION'S DECISION TO PAY QFs FOR AVOIDED CAPACITY IN THE SUB 140 PROCEEDING.

59 *Id*.

60 *Hydrodynamics, Inc.*, 146 FERC ¶ 61, 193 at P 35 (2014).

61 *Id*. at P. 34.

62 *Id*. at P. 35.

63 Public Staff Hinton Testimony, at 14-15.

A. In the Sub 140 proceeding, the Commission exercised its discretion in setting avoided cost rates not to authorize a capacity rate reduction based on a utility's near-term lack of capacity need "as a generic principle." However, as Public Staff Witness Hinton notes, "the sheer volume of QF projects currently being developed in North Carolina . . . is unparalleled."[64] Thus, the Public Staff supports the Companies' proposal to limit capacity payments until their respective IRPs identify a capacity need.[65] The Companies, likewise, request that the Commission reconsider this determination and approve its proposal in light of these evolving economic and regulatory circumstances.

VI. <u>CIRCUMSTANCES WHERE VIOLATIONS OF NERC/SERC STANDARDS ARE IMMINENT ARE "SYSTEM EMERGENCIES" THAT JUSTIFY EMERGENCY CURTAILMENT</u>

Q. PLEASE DESCRIBE THE COMPANIES' AMENDMENT TO THEIR STANDARD OFFER TERMS AND CONDITIONS WITH RESPECT TO BEING ABLE TO CURTAIL QF GENERATION IN A SYSTEM EMERGENCY.

A. The Companies have proposed to amend paragraph 14 of their Terms and Conditions to provide notice that an emergency condition justifying curtailment of QF generation includes any circumstance that requires action by the Companies to comply with mandatory NERC/SERC regulations, such as the BAL standards, which Witness Holeman discusses in more detail.

Q. WHAT IS THE PUBLIC STAFF'S POSITION ON THIS ADDITION TO THE COMPANIES' TERMS AND CONDITIONS?

64 Public Staff Hinton Testimony, at 7.

65 Public Staff Hinton Testimony, at 14.

A. After discussing in detail the unique challenges from increasing amounts of PURPA "must-take" and non-dispatchable generation that the Companies face, Public Staff Witness Metz agreed that potential imminent violation of a BAL standard is an emergency that would justify curtailment of QF purchases and recommends that the Commission make explicit findings to that effect.[66] The Public Staff further recommended that the Companies file its curtailment guidance with the Commission, along with requirements on how curtailment events would be reported, and what information would be included in each report. As noted by Witness Holeman, the Companies agree with these recommendations and are currently in the process of refining their processes with respect to QF curtailment. The Companies also intend to continue their discussions on our non-discriminatory processes and procedures for curtailing both Companies' facilities and QFs in system emergencies with the Public Staff as soon as they are complete.

Q. IS THE COMPANIES' PROPOSED CLARIFICATION OF SYSTEM EMERGENCIES CONSISTENT WITH PURPA AND IN THE PUBLIC INTEREST?

A. Yes. As discussed in my direct testimony and identified by Public Staff Witness Metz, FERC's regulations permit a utility to discontinue purchases during system emergencies if such purchases would contribute to such

66 Public Staff Metz Testimony, at 13-14 (recommending the Commission "affirm that utilities have the authority to curtail QFs during system emergencies, explicitly find that imminent violations of the NERC BAL Standards constitute system emergencies, and further investigate how to provide stakeholders clarity on curtailments made due to system emergencies.").

emergencies.[67] This curtailment must be done on a nondiscriminatory basis. Second, the Companies agree with Public Staff Witness Metz that an imminent violation of a BAL standard is a system emergency that could result in significant service disruptions to our customers. Therefore, the proposed clarification serves the public interest.

Q. IS NCSEA WITNESS JOHNSON'S RECOMMENDATION FOR "TAKE OR PAY" CONTRACTS A VIABLE ALTERNATIVE TO CURTAILING QFs IN AN EMERGENCY?

A. No, it is not. The Companies strongly disagree that the Commission should adopt a recommendation that results in our customers paying for QF solar power that is simply "discarded" or not used to meet system load. Witness Johnson provides no evidence that any other public service commission has ever approved such a contract in its implementation of PURPA, and it seems completely unjust and unreasonable to mandate such a proposal in North Carolina based upon current economic and regulatory circumstances. Further, nothing in PURPA requires customers to pay QFs for unused or unneeded energy or capacity, as FERC confirmed in establishing its regulations in Order No. 69:

> "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

67 18 C.F.R. 292.307(b).

requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale."[68]

VII. <u>THE COMPANIES DO NOT SUPPORT DEVELOPING A STANDARD OFFER SOLAR SPECIFIC RATE IN THIS PROCEEDING, BUT AGREE THAT SUCH A PROPOSAL MAY BE REASONABLE IN THE FUTURE</u>

Q. HAVE OTHER PARTIES RECOGNIZED THAT THE COSTS AVOIDED BY SMALL SOLAR QFs MAY BE DIFFERENT THAN OTHER QF GENERATORS, AND SUGGESTED THAT IT WOULD BE APPROPRIATE TO DEVELOP SOLAR QF-SPECIFIC AVOIDED COST RATES?

A. Yes. Both Public Staff Witness Hinton and NCSEA Witness Johnson recommend that the Utilities should be required to establish solar QF-specific avoided energy rates. Witness Hinton focuses on a single issue – limiting the off-peak avoided energy profile of solar QFs to daytime hours – to suggest that a separate avoided energy rate for small solar QFs should be developed.[69] Witness Johnson more generally recommends "the Commission initiate steps to provide stronger, more precise peak and off peak price signals in the QF tariffs" and identifies that price signals may be used to better address the Companies' growing concerns about operationally excess energy.[70]

Q. PLEASE RESPOND.

A. Consistent with prior biennial avoided cost proceedings, the Companies have developed "generic" standard offer rates that would be available to all non-

68 Order No. 69, *supra* note 14 at 25-26. (emphasis added).

69 Public Staff Hinton Testimony, at 63-64.

70 NCSEA Johnson Testimony, at 197-98.

hydroelectric small QFs now capped at 1 MW or less. In designing the Schedule PP rates, the Companies relied upon traditional application of the peaker methodology and did not focus on either the specific energy-related or capacity-related characteristics of a small solar QF or other type of small QF generator. As I explained earlier and as further discussed by Witness Snider, capping eligibility for the standard offer at 1 MW will allow the Companies to more precisely determine the avoided energy and capacity value attributable to larger utility-scale QFs, including solar QFs, in the future based upon a QF's specific characteristics. FERC's regulations have long recognized that the specific characteristics of a QF's power may be considered in setting rates for individual QFs (18 C.F.R. 292.304(e)). FERC also recently reiterated that "the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity" may be taken into account in setting avoided cost rates.[71] Importantly, however, the Companies do not believe it is appropriate in this proceeding to consider only one individual aspect of a small solar QF's avoided energy value without considering other specific characteristics of a QF technology.[72] Notably, the Public Staff identified other considerations, including integration costs and line losses that are not being taken into account, among others, in the Schedule PP rate design. To the extent a small solar QF believes it has greater value in off-peak

71 *Windham Solar Order, supra* note 36, at P. 6.

72 *Order Setting Avoided Cost Input Parameters*, Docket No. E-100, Sub 140 (recognizing that "proposal isolates one potential benefit of solar generation but fails to account for any of the potential costs inherent in such intermittent resources.").

hours than currently being recognized in the Schedule PP rate, that QF can request to negotiate a PPA that more accurately and completely reflects its current avoided costs. The Companies also agree that it may be reasonable in the next avoided cost proceeding to consider a small solar-specific QF avoided cost rate design if all avoided costs and potential benefits of incremental solar QF generation on the Companies' systems are taken into account.

CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities	)))))	**REBUTTAL TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy Corporation ("Duke Energy") as Director of Carolinas Resource Planning and Analytics.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), (collectively, the "Companies") on February 21, 2017.

Q. PLEASE PROVIDE A SUMMARY OF THE STRUCTURE OF YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony is organized into the following sections.

I. General Observations and Considerations

II. Issues Related to Calculating the Avoided Energy Rate

III. Issues Related to Calculating the Avoided Capacity Rate

I. <u>GENERAL OBSERVATIONS AND CONSIDERATIONS</u>

Q. WHAT ARE YOUR GENERAL OBSERVATIONS OF INTERVENOR TESTIMONY IN THIS PROCEEDING?

A. Intervenors raise a variety of issues that suggest the North Carolinas Utilities Commission ("Commission" or "NCUC") should raise both the avoided energy and avoided capacity rates filed in this proceeding as well as extend the fixed price term of those rates. These recommendations are made despite overwhelming evidence that residents and businesses in North Carolina are paying substantially more for purchased qualifying facility ("QF") generation (specifically QF solar generation) than they would have for power generated by other means. In my view, the magnitude of the overpayment risk, pending the outcome of this proceeding, is a significant factor facing the Commission and the State, as a whole. While I will address several of these individual issues in my rebuttal testimony, I believe it is critically important to not lose sight of the overall impact of the energy and capacity value of QF power and QF solar power, in particular.

Q. WHAT OVERALL FACTORS SHOULD THE COMMISSION CONSIDER IN DETERMINING THE REASONABLENESS OF THE COMPANIES' AVOIDED COST RATES FILED IN THIS PROCEEDING?

A. Consideration should be given to the overall factors influencing the value of QF energy and the value of QF capacity. The two most important influencing factors for QF energy value are first, the underlying fuel prices that determine the value of avoided marginal system energy and second, the specific QF's ability to avoid those fuel purchases. With respect to QF capacity value, the principal consideration requires a valid comparison between how much generation will actually be avoided from the QF relative to how much the QF is being compensated for avoiding generation under the filed rates. Finally, it should be noted that a solar specific rate would produce a lower avoided cost rate as compared to the rates filed in this proceeding as discussed later in my testimony and by Witness Bowman in her rebuttal testimony.

Q. OVER THE LAST TWO YEARS, HOW HAVE THE COMPANIES' SYSTEM MARGINAL COSTS AS DETAILED IN FERC FORM 714 TRENDED COMPARED TO THE AVOIDED ENERGY RATES APPROVED IN THE LAST AVOIDED COST PROCEEDING IN DOCKET NO. E-100, SUB 140 ("SUB 140")?

A. The Companies calculated their previous 10-year annualized, non-hydroelectric ("hydro") energy rates pursuant to the Commission's December 17, 2015 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 140. Those rates that went into effect on March 1, 2016 were $42.90 per Megawatt-hour ("MWh") for DEC and $42.70/MWh for DEP, respectively. Comparatively, as filed in FERC Form 714, the Companies' system marginal costs dropped from approximately $33.65/MWh in 2015 to $29.16/MWh in 2016. This disconnect between system operating costs and avoided cost rates was mainly driven by the required inclusion of fundamental fuel prices in the Phase 2 Sub

140 Order's avoided cost rates, as well as a drop in delivered gas prices of nearly 20% across both Companies from 2015 to 2016.

Q. PLEASE DESCRIBE HOW TRENDS IN THE NATURAL GAS MARKETS INFLUENCE THE UTILITIES' COST OF AVOIDED GENERATION ON A GOING FORWARD BASIS.

A. There is little debate that advancements in shale gas production have changed the natural gas market landscape, drastically reducing the cost of natural gas. Consequently, and by extension, the Companies and other utilities' cost of avoidable energy production has also declined significantly over the last several years. This transformation has occurred at a rapid pace.

My Confidential Figure 1 demonstrates the average market fuel price of natural gas over the next ten years is 34% lower than prices used in calculating the avoided energy cost rate in the 2012 avoided cost proceeding, Docket No. E-100, Sub 136 ("Sub 136"), which used five years of market fuel prices and a one-year transition to a fundamental fuel forecast. The average price of natural gas is also 30% lower than those used in calculating the 2014 Sub 140 avoided energy cost rate, which included five years of market fuel prices and five years of fundamental fuel forecasts as directed in the Commission's "Phase 2" Sub 140 Order.[1]

[1] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 27-28, 54, Docket No. E-100, Sub 140 (Dec. 17, 2015) ("Phase 2 Sub 140 Order").

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Furthermore, on April 5, 2017, Duke Energy Progress purchased a long-term natural gas forward position that included the remainder of 2017 through the year 2026 at prices 6% percent lower than the relative prices used in establishing the 10-year small hydro rates filed in this proceeding and presented in Confidential Figure 1 above. Confidential Figure 2 further illustrates both the commodity trend and the attendant risk of establishing long-term QF rates that do not include periodic adjustments.

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Notably, while the majority of my testimony focuses on natural gas price trends, coal prices have also seen declines since the Commission approved avoided cost rates in Sub 136 and Sub 140 as well. The average price of delivered coal over the next ten years is approximately 25% lower than prices used in calculating the 2012 Sub 136 avoided costs and approximately 8% lower than those used in calculating the 2014 Sub 140 avoided cost rates.

Locking in coal prices in long-term contracts carries similar risk as natural gas if rates do not include periodic adjustments.

Q. PLEASE SUMMARIZE YOUR GENERAL OBSERVATIONS WITH RESPECT TO INTERVENORS' POSITIONS TO RAISE BOTH ENERGY AND CAPACITY RATES IN THE PROCEEDING.

A. In summary, the Companies have historically produced energy well below what customers are paying for QF energy. On a forward-looking basis intervenors suggest substantial increases in the 10-year energy rate at the same time the Companies are relying on significantly lower market-based gas forecasts in their integrated resource planning process, and as the Companies have also recently purchased natural gas at costs even lower than those used in establishing the 10-year hydro rates filed in this docket. Additionally, that there is a large discrepancy in views over the long-term value of avoided QF energy also points to the risk of establishing long-term fixed energy rates especially above market levels as suggested by intervenors.

With respect to capacity rates, the use of general QF capacity rates as filed dramatically overstates the incremental capacity value of additional solar specific QF generation on the system. As DEC, DEP and Dominion North Carolina Power ("DNCP") have demonstrated the addition of incremental solar to their respective systems will have little to no impact on their need for capacity. Thus, I believe it is important for the Commission to consider these general factors and circumstances surrounding the proposed energy and capacity rates in this proceeding as it weighs specific issues brought forth.

<u>II. ISSUES RELATED TO CALCULATING AVOIDED ENERGY RATE</u>

Q. WHAT ISSUES WILL YOU BE ADDRESSING WITH REGARD TO THE ENERGY PAYMENT IN YOUR REBUTTAL TESTIMONY?

A. I will be addressing:

1. Two-year Reset of Energy Prices vs. 10-year Fixed Prices
2. Market Prices vs. Fundamental Fuel Prices
3. The Merits of a Solar Only Energy Rate
4. Line Losses in Calculating Standard Offer Avoided Costs
5. Ancillary Costs in Calculating Standard Offer Avoided Costs

<u>TWO-YEAR RESET OF ENERGY PRICES VS. 10-YEAR FIXED PRICES</u>

Q. WHAT ARGUMENTS ARE MADE BY THE INTERVENORS AGAINST THE TWO YEAR RESET OF ENERGY PRICES VS. 10-YEAR FIXED PRICES?

A. Public Staff Witness Hinton, North Carolina Sustainable Energy Association ("NCSEA") Witness Johnson, and Southern Alliance for Clean Energy ("SACE") Witness Vitolo each argue against the Companies' proposal to biennially reset energy rates as part of the 10-year standard offer contract. All three witnesses argue that this adjustment will not provide reasonable opportunity, in the words of Witness Hinton, "to attract capital from potential investors."[2] Witnesses Johnson and Vitolo argue that this adjustment would significantly increase the risks borne by QF developers, as well as, increase the risks borne by the Companies' customers.[3] Witness Vitolo additionally argues that this proposal treats QFs differently than assets owned by the Companies, even when the QF contracts represent a similar long-term fixed price obligation to the Companies' commitment to build a conventional generating plant.[4]

Q. HOW DO YOU RESPOND TO THE INTERVENOR TESTIMONY THAT RESETTING THE ENERGY PRICES EVERY TWO YEARS WILL NOT ALLOW QFS TO OBTAIN FINANCING FOR QF PROJECTS?

A. The intervening parties fail to acknowledge that the Companies are proposing a 10-year obligation to the QF with a known capacity payment and a known energy payment in the first two years. Over the 10-year term, the energy payment is reset every two years consistent with the then prevailing two-year rates as approved by the Commission. Ten-year purchase power agreements have been offered to and accepted by large solar QFs in the Companies'

[2] Public Staff Hinton Testimony, at 57-60.
[3] NCSEA Witness Johnson Testimony, at 158-160; SACE Witness Vitolo Testimony, at 19-20.
[4] SACE Witness Vitolo Testimony, at 20-21.

service area, demonstrating that the 10-year term is readily financeable. Accordingly, while the 10-year term is demonstrated to be financeable (at least for larger QFs), what intervenors are implying is that within the filed rates, not a large enough portion of the payment is fixed to attract financing. Unlike public utilities, QF developers are not required to make their financial and operating costs public, so it is unclear if these implications are factual. To my understanding nothing in PURPA requires states to offer price levels high enough to attract financing. The rate as filed in this proceeding, however, offers a sufficient term with a portion of the revenues fixed and a portion adjusted to better match future avoided energy value. It is fully consistent with PURPA and represents an appropriate adjustment to stem the persistent overpayment risk that our consumers are experiencing.

Moreover, the Commission has consistently stated it must "continually reconsider" the requirement for 10-year and 15-year contract terms as economic circumstances change from one biennial proceeding to the next. In past proceedings, the Commission has concluded that the 15-year maximum contract struck a balance between encouraging QF development and reducing the utilities' exposure to overpayments because the facilities entitled to long-term rates were generally of limited number and size. The significant proliferation of 5 MW solar QFs in the DEP and DEC service territories, however, has resulted in the number of QFs entitled to these long-term contracts no longer being of limited number and size. The proposed rate structure in this proceeding restrikes that balance between the development of

QFs and the Companies' exposure to overpayments when accounting for the current economic and regulatory circumstances.

Q. SO YOU DISAGREE WITH NCSEA WITNESS JOHNSON'S ARGUMENT THAT MOVING TO A BIENNIAL UPDATE OF ENERGY PAYMENTS IS "LOSE-LOSE" FOR THE COMPANIES' CUSTOMERS?

A. I strongly disagree with Witness Johnson's assertion. The move to a two-year reset is actually a "win-win" for the Companies' customers. Witness Johnson asserts that solar "currently brings a degree of pricing stability into electric rates; the benefits of that stability would be largely eliminated by this proposal." [5] Just because rates are stable, does not mean the customer benefits, especially if stability comes at the expense of rates that are unnecessarily high. For example, the utility could simply purchase ten years of natural gas at well above forward market prices for natural gas in the name of price stability. However I do not believe that would be in the best interest of customers. nor do I believe the Commission would find that practice prudent.

Witness Johnson also asserts that non-PURPA sellers of power who burn fuel are higher risk than solar QFs because those sellers "seek a pricing structure that gives them the ability to push the risk of fuel price changes forward to the purchasing utility, which in turn pushes the risk forward to their retail

[5] NCSEA Witness Johnson Testimony, at 158 -59

customers."[6] To support his assertion that those non-PURPA contracts are higher risk than the solar QF contracts, Witness Johnson points to my testimony stating the energy payments to those non-PURPA sellers "are generally linked to a real-time fuel price index." Witness Johnson fails to recognize, however, that the linking to a real-time fuel price index helps to lower risk, rather than increase risk. The non-PURPA contracts to which he is referring are third-party owned dispatchable natural gas units. Their dispatchable nature allows for the economic optimization of dispatch based on prevailing gas prices. For example, if gas prices rise the unit will run less while, conversely, when prices fall the unit will run more. On the other hand, PURPA must-take generation is not dispatchable and is taken at a fixed price without consideration to real time price signals or the Companies' real time need for energy to serve load. As such, there is no ability to adjust the amount of generation received based on real time price signals. As a result, customers only benefit if realized gas prices over time are consistently above those used in establishing the original QF rate. Unfortunately the exact opposite has consistently occurred in recent years resulting in significant customer overpayments and significant future overpayment risk.

Q. IS PUBLIC STAFF WITNESS HINTON'S SUGGESTION TO "LINK AVAILABLE ENERGY RATES TO A PUBLICLY AVAILABLE

[6] NCSEA Witness Johnson Testimony, at 160.

COMPOSITE FUEL INDEX" A REASONABLE ALTERNATIVE TO THE TWO YEAR RESET OF ENERGY PAYMENTS?

A. Yes, as discussed above, linking energy rates to a publicly available composite fuel index could be a reasonable alternative to the two year reset of energy payments. The linking of energy rates to a fuel index accomplishes a similar goal of minimizing the risk of overpaying QFs for the energy that they provide. As discussed by Witness Bowman, the Companies plan to further evaluate incorporating this proposal into the standard offer rate design in the next biennial proceeding,

Q. PLEASE EXPLAIN THE COMPROMISE PROPOSAL THE COMPANIES ARE PRESENTING AS AN ALTERNATIVE TO THE TWO YEAR RESET OF ENERGY PAYMENTS IN THIS PROCEEDING.

A. As discussed by Witness Bowman, the Companies have determined that offering small standard offer QFs the option to "fix" the two year avoided energy rate for the full 10-year term is an appropriate compromise in response to the testimony offered by intervenors that small QF investors will view energy revenues in years beyond the proposed biennial update as risky and that a longer-term fixed rate (seemingly for both energy and capacity) is needed by smaller QFs in order to attract capital. Currently, the Companies' two-year fixed Schedule PP annualized energy rates are only slightly below the fixed 10-year Schedule PP-H annualized energy rates, which I view as an acceptable, albeit imperfect, allocation of longer-term forecast risk between

QFs and the Companies' customers at this time. Further, as noted by Witness Bowman, the Companies submit this compromise alternative as an interim solution to address concerns raised in this case. The Companies plan to reevaluate these concerns in the next biennial avoided cost proceeding, along with the fuel index proposal offered by the Public Staff.

MARKET VS. FUNDAMENTAL FUEL PRICES

Q. PLEASE EXPLAIN THE COMMISSION'S RECENT CONCLUSIONS RELATED TO FORWARD MARKET FUEL PRICES VERSUS FUNDAMENTAL FORECAST-DERIVED FUEL PRICES IN ESTABLISHING AVOIDED ENERGY COST RATES.

A. .In Phase 2 of the Sub 140 proceeding, the Companies' proposed to continue a trend initially begun in recent integrated resource plans ("IRPs") of more heavily relying upon forward market price data as a more precise indicator of the near-term future commodity costs of natural gas for purposes of calculating the Companies' avoided energy cost rates. Specifically, the Companies proposed to rely upon 10 years of forward market price data as a more accurate indicator of the future commodity costs of natural gas and to then transition to fundamental forecast data starting in year 11. However, at the time the Companies filed their proposed avoided cost rates in Sub 140 Phase 2, the Companies' then pending 2014 IRPs had relied upon only five years of forward market price data before transitioning to reliance on fundamental forecast data for the remainder of the Companies' 30 year planning horizon. In its Sub 140 Phase 2 Order, the Commission recognized that changing market conditions supported the Companies' increased reliance on forward market price data, acknowledging "the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates."[7] However, the Commission declined to approve the Companies' forecasts, emphasizing the important relationship between the Companies' IRP planning process and the biennial avoided cost proceedings, including the objective of maintaining internal consistency between these proceedings.[8] The Commission directed that, to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations."[9]

Q. WHY HAVE THE COMPANIES RELIED UPON 10 YEARS OF FORWARD MARKET FUEL PRICE DATA TO SUPPORT PRUDENT, LEAST-COST UTILITY RESOURCE PLANNING IN THEIR MOST RECENT BIENNIAL IRPS?

[7] Sub 140 Phase 2 Order at 27.
[8] Sub 140 Phase 2 Order, at 27-28.
[9] *Id.* at 55.

A. By 2014, it became apparent that the natural gas market in the United States had changed with the rapid increase in natural gas production due to technology advancements. With this increase in natural gas production, longer range options for purchasing natural gas became more available, and as a result, the Companies began requesting quotes for 10-year purchases of natural gas from various brokerage firms. As a result, the Companies have developed both their 2015 IRP updates, filed September 1, 2015, in Docket No. E-100, Sub 141 ("2015 IRP Update") as well as their 2016 biennial IRPs filed September 1, 2016 in Docket No. E-100, Sub 147 ("2016 Biennial IRP"), based upon 10-years of forward market price data and transitioning to fundamental forecast-derived data in year 11.

Q. HOW HAVE GAS PRICES USED IN THE COMPANIES' IRPS AND AVOIDED COST DOCKETS CHANGED OVER THE LAST SEVERAL YEARS?

A. Confidential Figure 3 below depicts the 10-year fuel prices from DEC's IRPs and avoided cost filings dating back to 2012. The figure also includes the most recent 10-year fuel purchase. If avoided cost rates were filed today, these lower fuel prices would be used in the calculation the avoided energy rate calculation.

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The 10-year levelized fuel prices have dropped nearly 40% since 2012 compared to the most recent 10-year fuel price quote received by the Companies in early April 2017. In fact, since the avoided cost rates were filed in mid-November 2016, the 10-year levelized natural gas price has dropped 6%.

Q. DO THE FUNDAMENTAL FORECASTS THAT THE UTILITIES HAVE USED IN THESE SAME FILINGS REFLECT A SIMILAR TREND?

A. Partially. The Fundamental Price Forecasts are clearly lagging the market prices in terms of seeing a structural difference in the natural gas marketplace. As shown in Confidential Figure 4 below, the Fundamental Price Forecast used in the 2016 Avoided Cost filing is showing natural gas price estimates at least $1/MMBtu higher than the actual market prices starting in 2020. It should be noted that fundamental forecasts take significant time to develop and are often only released by research firms once or twice per year. Additionally, the preparation of avoided cost filings also takes months to prepare and then can be subject to an extended regulatory review. As a result fundamental price estimates can be well over a year old by the time rates go into effect.

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Q. REFERRING TO THE LONG-DATED GAS PURCHASE PREVIOUSLY MENTIONED, PLEASE COMPARE THIS MARKET PURCHASE WITH THE AVOIDED COST FUEL PRICES USED TO ESTABLISH RATES IN THIS DOCKET AS WELL AS WITH THE FUNDAMENTAL FUEL FORECAST SUGGESTED BY PUBLIC STAFF WITNESS HINTON.

A. On April 5th, DEP purchased forward gas contracts for 2,500 MMBtu/day for the period starting in May of 2017 and ending in December of 2026. This transaction demonstrates market liquidity and provides a tangible price point for the natural gas market over the equivalent period of the 10-year hydro rate. As shown in Confidential Figure 5 below, the natural gas was purchased at a price just below the market prices used in the 2016 Avoided Cost filing. The 10-year levelized price of this purchased gas is approximately 6% lower than the market prices used in establishing the rates filed in this docket in November of 2016, and approximately 20% lower than the 5 year Market plus 5 year Fundamental Forecast blend of 10-year prices as suggested by Public Staff Witness Hinton. This highlights the overpayment risk I spoke of earlier regarding the suggestion to recalculate rates based on a fundamental forecast.

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Q. WITH THAT BACKGROUND, HOW HAVE THE COMPANIES INCORPORATED THE USE OF 10 YEARS OF FORWARD MARKET FUEL PRICE DATA IN THEIR BIENNIAL AVOIDED ENERGY COST RATES PROPOSED IN THIS PROCEEDING?

A. Consistent with the Companies' recent IRPs, 10 years of forward market price data is used to develop the Schedule PP-H rates proposed in this proceeding. However, because the Companies' Schedule PP non-hydro avoided energy cost rates are based only on the Companies' near-term, two-year forecasted avoided energy rates, the issue of reliance on forward market price data versus fundamental forecast data ten years out is a non-issue. This is significant, as the Companies' proposal best assures that future avoided commodity costs that underlie the near-term avoided energy rate are most accurate. If the Commission approves the Companies' proposed Schedule PP rate design, as proposed, the longer-term forecasted energy costs, and the associated risks of over-estimating or under-estimating future commodity costs based upon forward market data versus fundamental forecast data simply does not impact the Companies' proposed rates. However, if the Commission disagrees with the Companies' Schedule PP rate design to biennially reset the energy rate then the market price versus fundamental fuel forecasts arguments are significant both for purposes of this proceeding as well as for the Companies' prudent, least cost resource planning in future IRPs.

Q. WHAT ARGUMENTS DO THE INTERVENORS MAKE AGAINST THE USE OF 10 YEARS OF FORWARD MARKET NATURAL GAS DATA, AS USED IN THE COMPANIES' 2015 AND 2016 INTEGRATED RESOURCE PLANS?

A. Public Staff Witness Hinton argues that "ten-year futures are relatively illiquid, meaning that the number of natural gas price investors willing to make buy and sell decisions on prices ten years out in the future is much smaller than the number of investors in the futures market for five years into the future." [10] Witness Hinton also argues that the use of Fundamental Prices, that are "developed by energy economists and gas analysts" are more appropriate for long-term price forecasts because they are based on future supply and demand projections and "involve a more measured and tempered response to expected changes in the natural gas market." [11]

Q. PLEASE RESPOND TO WITNESS HINTON'S CONCERN OVER MARKET LIQUIDITY.

A. Based on my experience, 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 New York Mercantile Exchange ("NYMEX"). If one is simply viewing contracts that trade on the NYMEX that could lead to the conclusion that long-dated gas markets are illiquid. Typically only actual market participants that purchase or sell gas forward positions engage these financial institutions. 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 natural gas forward position.

Q. PLEASE RESPOND TO WITNESS HINTON'S CONTENTION THAT USE OF FUNDAMENTAL PRICES ARE MORE APPROPRIATE THAN USE OF ACTUAL MARKET PRICES.

[10] Public Staff Witness Hinton, at 33.
[11] Public Staff Hinton Testimony, at 32.

A. There are several issues with this assertion.

First, this approach results in an immediate and extremely significant overpayment risk for customers. QF transactions represent significant forward purchased power obligations on behalf of customers. Today those transactions total more than $3 billion dollars. Very simply, the Companies may either purchase fuel or purchase power, or both, to satisfy future customer energy needs. PURPA requires customers be indifferent between the two. 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. By extension, if the Commission accepted Witness Hinton's argument to transact forward power QF purchases based on fundamental gas prices over market prices, it logically follows that the utility would also be deemed prudent to purchase natural gas at above available market prices so long as they were at or below fundamental projections. This highlights the inconsistency of purchasing power at forward fundamental forecasts while purchasing gas at market prices.

Second, Witness Hinton implies that his approach is more consistent with the avoided cost approach taken in Sub 140 Phase 2. However, in the Phase 2 Order, discussed above, the Commission emphasized that, to the extent the Utilities utilized forward prices and long-term forecasts to calculate their avoided energy rates, they should use the same approach as used in their

IRPs filed the same year.[12] Consistent with the Commission's instructions in the Sub 140 Phase 2 Order, the Companies have used 10-year forward market prices in their last two IRPs.

Third, Witness Hinton's recommendation to use fundamental prices is seemingly in conflict with his alternative recommendation to consider offering QFs avoided energy rates based on a composite commodity price index. For example, assume a straight forward natural gas commodity indexed QF rate. Such a structure would pay the QF a market based real time natural gas price index multiplied by a calculated average marginal heat rate of the utility's system. While this rate structure does not fix an energy price for the QF it allows the QF to fix its energy price at any point by forward hedging the gas price upon which the variable rates are based. This allows the QF to choose whether or not to fix their price of power at their discretion. The inconsistency in Witness Hinton's two positions comes from the fact that under his proposed alternative index structure the QF could only fix their revenues at the prevailing forward market price for natural gas (they could not hedge at fundamental price levels). By definition if the QF believed fundamental forecasts were pointing to higher prices they could opt to not fix prices at current market levels and take the risk that future prices rose to fundamental price forecasted levels. In contrast, by recommending the Companies adopt fundamental prices to set long-term rates in this Docket,

[12] Phase 2 Sub 140 Order, at 27-28, 55,

Witness Hinton is essentially suggesting that North Carolina consumers take on this risk by providing a transactable forward market for the QF at rates above the prevailing natural gas market. This transfers significant price risk to the consumer. As a result North Carolina would be in the unique position of creating a transactable forward power market well above the equivalent gas market. This dislocation between power and gas markets would certainly not be equitable for consumers.

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S CONCERN THAT MARKET FUEL PRICES ARE EXCESSIVELY CONSERVATIVE AND THAT FUNDAMENTAL FORECASTS ARE A BETTER INDICATOR?

A. I disagree. The use of market prices better aligns forward power prices and forward gas prices. Since Sub 140 Phase 2, when the Companies first proposed 10 years of market data, the market prices for natural gas have continued to substantially fall, proving that the natural gas market has shifted, and the lower prices are not just temporary.

Q. WHAT ADDITIONAL ISSUES ARISE WITH USING FUNDAMENTAL FORECASTS AS A BASIS FOR CALCULATING QF AVOIDED ENERGY RATES?

A. At any point in time only a single forward market exists for natural gas prices. Conversely, at any point in time a wide range of fundamental price forecasts are available. This range is clearly shown by the deviation between DNCP's fundamental forecast and the Companies' fundamental forecasts, as presented in the graph on page 35 of Witness Hinton's testimony, which I have replicated below as Confidential Figure 6.

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

[13] Public Staff Hinton Testimony, at 35

As an initial matter, the Companies disagree with Witness Hinton's observation that reliance on the DEC 2016 IRP fundamental forecast and the DNCP avoided cost forecast approach are "more comparable."[14] As the graph clearly shows, the DEC 2016 IRP fundamental forecast, instead of being "comparable" to DNCP's avoided cost forecast highlights the varying fundamental views in the industry. Confidential Figure 6 shows that DNCP and DEC have very different fundamental forecasts, and I question whether setting QF rates based on materially different assumed gas prices is appropriate. Moreover, the Public Staff's reliance on fundamental forecasts for calculating avoided cost rates raises several issues, including identifying the criteria that would be used to establish the reasonableness of a fundamental price forecast, and what the positions of the intervenors would be if the fundamental forecasts were below the transactable market data. The Public Staff's testimony also raises the question of whether, going forward, the Commission will required to adopt a "preferred price forecast" for IRP and avoided cost proceedings. In addition to the DNCP and DEC forecasts, I am aware that multiple fundamental price forecasts are available; thus, determining the reasonableness of any one single fundamental price forecast over another may be difficult.

In sum, disagreements over which fundamental price forecast may be more accurate or whether forward market data is more reasonable for use in

[14] *Id.*

calculating future avoided cost rates masks the significantly more important question, which is "Have the Companies engaged in a reasonable and prudent, least-cost IRP planning process and is there a compelling reason to force inconsistency between the Companies' IRP methodology and their avoided energy cost methodology?" The Companies believe their current IRP methodology is reasonable and appropriate both for resource planning and for setting avoided energy cost rates. The Public Staff and other intervenors have failed to sufficiently explain why at this time the Companies should depart from the Commission's directive in its Phase 2 Sub 140 Order and not remain consistent with their previous IRP filings with respect to their fuel forecasts.

Finally, I also would reiterate that the Companies' proposed Schedule PP rate design using updated two-year energy forecast data to biennially reset avoided energy rates best mitigates the potential for long-term risk of over-estimating or under-estimating risk of commodity forecasts that may be wrong or markets that may change over time. As the two year rate is based on forward market gas prices it also maintains the critical link between forward QF power prices and forward market gas prices.

THE MERITS OF A SOLAR ONLY ENERGY RATE

Q. DO PUBLIC STAFF WITNESS HINTON AND NCSEA WITNESS JOHNSON ARGUE IN SUPPORT OF A SOLAR-SPECIFIC TARIFF?

A. Yes. Public Staff Witness Hinton argues that energy provided by solar facilities during off-peak daylight hours has value that is not currently being fully recognized and properly allocated in off-peak avoided energy rates under the current method. Witness Hinton argues that a solar facility's generation helps to avoid a utility's marginal production costs during daylight hours when the marginal costs are generally higher. By modeling a solar-specific profile, the solar facility would not be penalized for not being available during nighttime off-peak hours and this would serve to increase the off-peak rate that solar QFs receive.

NCSEA witness Johnson argues that the Utilities "should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified [by the utilities]." [15] Witness Johnson is concerned that "if the utilities continue to resist adopting technology-specific rates" other small power producers (i.e. wind, methane from landfills, hog or poultry waste and non-animal biomass) could be "penalized for problems (or perceived problems) that are specific to solar energy." [16]

Q. DO THE COMPANIES SUPPORT MOVING TOWARDS A SOLAR-SPECIFIC AVOIDED ENERGY RATE FOR LARGER QFs?

A. Yes, as also discussed by Witness Bowman, given the significant increase in solar QFs in the Companies' territories, use of a solar-specific rate in the

[15] NCSEA Witness Johnson Testimony, at 199.
[16] NCSEA Witness Johnson Testimony, at 198.

context of larger negotiated QFs is appropriate. Additionally, I believe it may be appropriate in subsequent standard offer filings to advance solar-specific QF rates.

Q. WHAT FACTORS SHOULD THE COMMISSION CONSIDER REGARDING A SOLAR QF'S SPECIFIC IMPACT ON ENERGY VALUE?

A. Generic QF rates established under the "Peaker Method" apply to any PURPA QF eligible for the Standard Offer. The Peaker Method as applied in North Carolina calculates energy value assuming an equal amount of generic QF generation is available in every hour. Fundamentally, non-baseload generation must track customer demand. Generation must be available and dispatchable to meet the dynamic needs of the consumer, which change minute-to-minute, hour-to-hour and day-to-day. Any 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. The Companies have stated that the cost of these additional operational adjustments are also a growing concern that should be identified for larger QFs, but that are not included in the calculation of the filed standard offer rates for small QFs in this proceeding.

Q. HOW WOULD THE COMPANIES SUGGEST IMPLEMENTING A SOLAR-SPECIFIC ENERGY RATE IF DIRECTED TO BY THE COMMISSION IN THIS PROCEEDING?

A. To calculate the energy specific portion of the avoided cost rates for solar QFs, the Companies would simply perform two production cost runs; one with, and one without, 100 MW of free solar generation using a general diversified solar profile. Today QF energy rates are generated using the same approach but assuming the free 100 MW is flat baseload generation in every hour. The use of a solar-specific profile could provide a more representative view of the actual system marginal energy benefits associated with incremental solar QF generation as opposed to the generic energy rate that assumes equal production in all hours.

Q. PUBLIC STAFF WITNESS HINTON SUGGESTS THAT SOLAR OFF-PEAK RATES WOULD INCREASE BETWEEN 8% AND 10% DUE TO THE DIURNAL PROFILE OF SOLAR COINCIDING WITH HIGHER COST OFF-PEAK HOURS. HOW DO THE COMPANIES RESPOND?

A. In response to a request from the Public Staff in this proceeding, the Companies conducted an analysis to produce an avoided energy rate under the traditional peaker method, but altered to include only a daylight hours solar load shape rather than a constant 100MW as used in the development of the standard offer tariff. Because the alternative analysis calculated avoided energy value using a free 100MW solar load profile to generate the associated energy value (energy rate) as compared to the filed rate that included 100MW free baseload resource in every hour of the year, the Companies agree that it represents a more precise estimate of the value of incremental solar-specific energy for solar QFs as compared to the filed standard offer rates.

Based on this analysis, a solar-only energy rate that more precisely calculates the energy value of 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* on average than the rates solar QFs are receiving under the generic small QF standard offer tariff that assumes constant energy production around the clock.

Q. WHAT ARE THE DRIVERS THAT LEAD TO A LOWER AVOIDED ENERGY COST RATE USING A SOLAR-SPECIFIC PROFILE?

A. Several factors influence this result.

First, the non-coincident nature of the solar shape with the Companies' load is a major contributor to the lower avoided cost rates with a solar-specific load profile. As shown in Figures 7 and 8 below, peak load typically occurs between 7 AM and 8 AM in the winter (using January as a representative data point) and between 4 PM and 5PM in the summer (using July as a representative data point). The peak for solar output typically occurs between 1PM and 2PM in the winter and between 2PM and 3PM in the summer. Additionally, and more importantly, on winter mornings solar generation starts providing energy to the system just as load is decreasing, and solar output begins to decline just as load is rebounding during winter evening hours. In the summer, solar aligns better with load, but again, solar output begins to decline as system demand is growing toward its afternoon peak.

As a simple example of solar's non-alignment with system load, consider that customers have varying needs over each of the 8,760 hours of a given year. Solar resources are available on a varying basis in approximately 55% of all the hours in the year. Of those hours in which solar is available, based on 2016 data, it only moved in the same direction as load about half of the time. The figures below also show that during critical peak hours is precisely when solar is moving the opposite direction of customer demand.

Figure 7: Average DEP Projected Load Shape for January Based on Forward 10-Year Load Forecast Overlaid with Average January Solar Shape

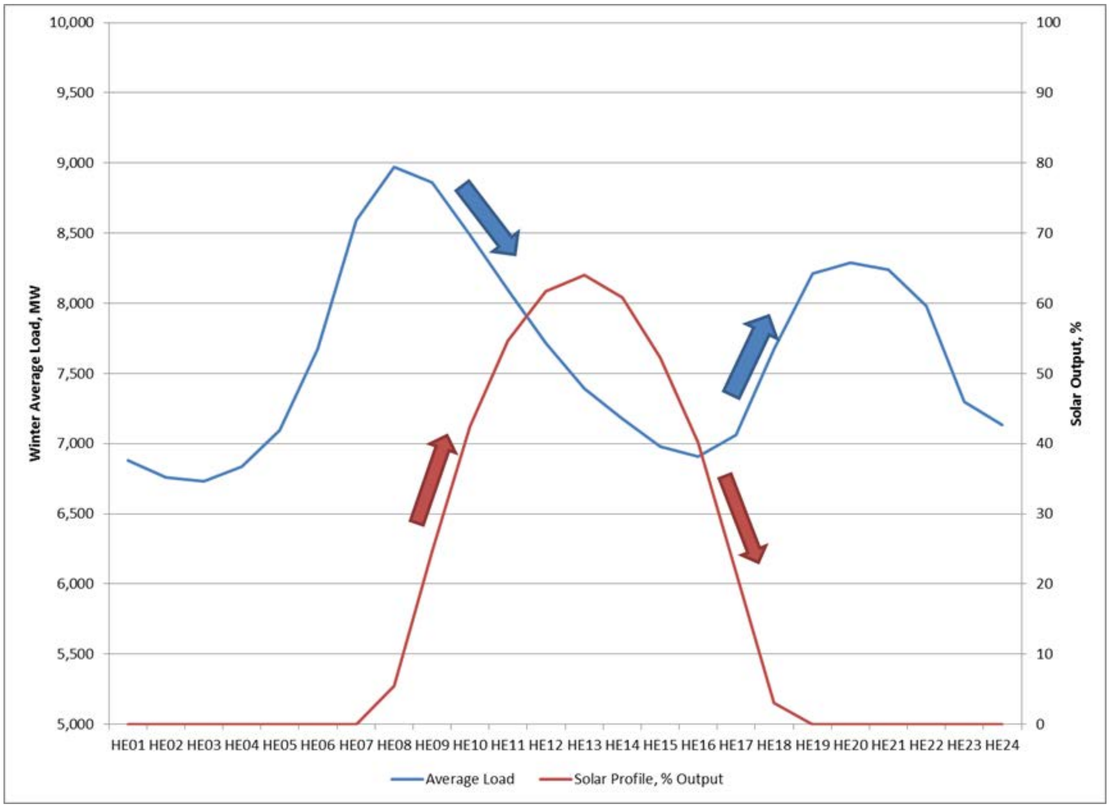
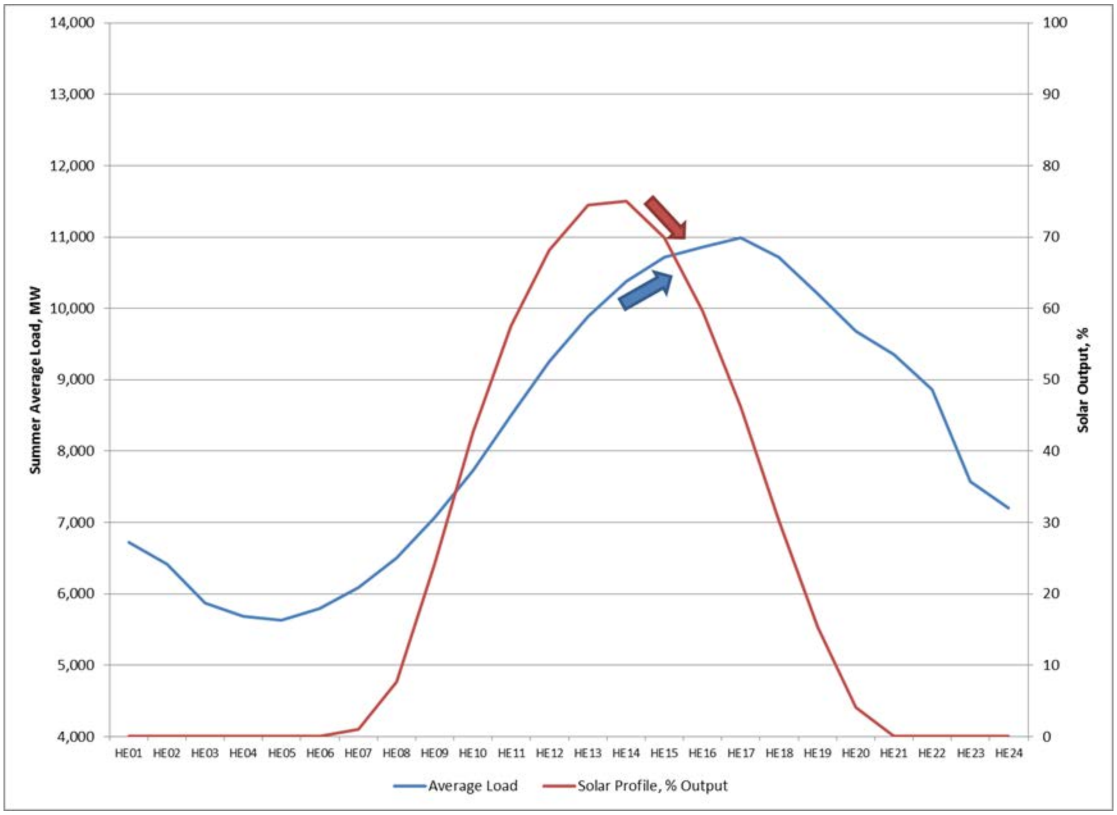


Figure 8: Average DEP Projected Load Shape for July Based on Forward 10- Year Load Forecast Overlaid with Average July Solar Shape



Further, as Figures 9 and 10 show below, as more and more solar is added to the system, the more non-coincident the solar shape becomes versus the load profile.

Figure 9: Average DEP Projected Load Shape for January with 1,000 MW Increments of Solar Generation

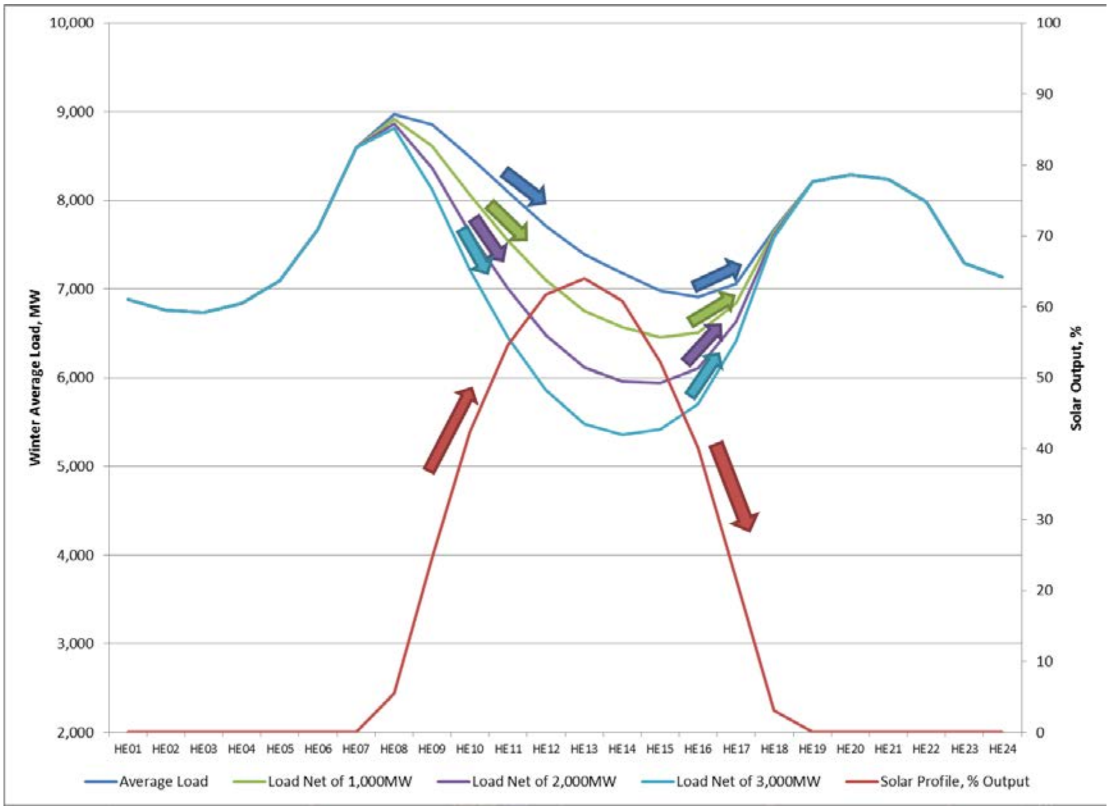
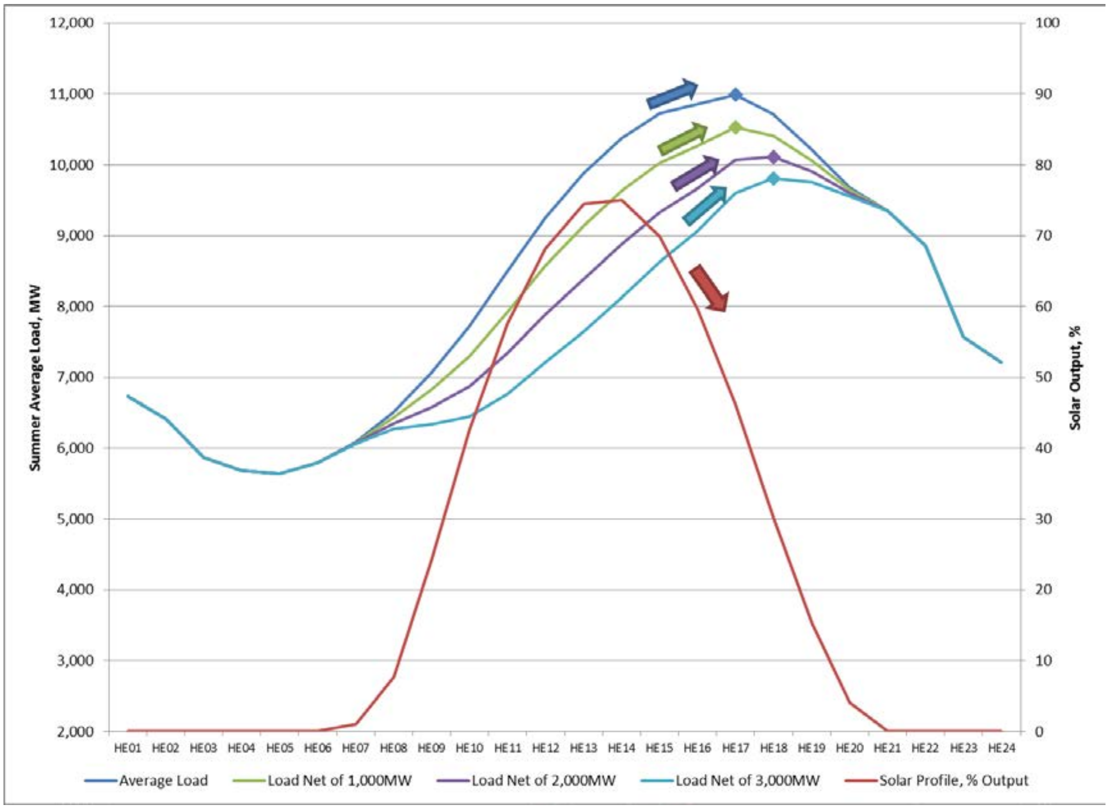


Figure 10: Average DEP Projected Load Shape for July with 1,000 MW Increments of Solar Generation



Because a solar profile is not coincident with load, it lacks coincidence with the Companies' highest marginal cost hours in both the winter and summer months. Figures 11 and 12 show an example of the system marginal costs overlaid with the solar load shape for both the winter and summer months using January and July averages respectively as representative data points. As the figures show, solar is not producing at high levels during the Companies' highest system marginal costs periods. As the figures also depict, solar is not fully available during the Option B on-peak hours for non-summer months (grey box). Under the current energy rate structure, which provides solar QFs with a rate based on a flat 100 MW load profile, QFs with solar generation profiles are being over-credited for energy during on-peak hours.

Figure 11: 10-Year Levelized DEP Projected Hourly Marginal Costs for January Overlaid with Average January Solar Shape

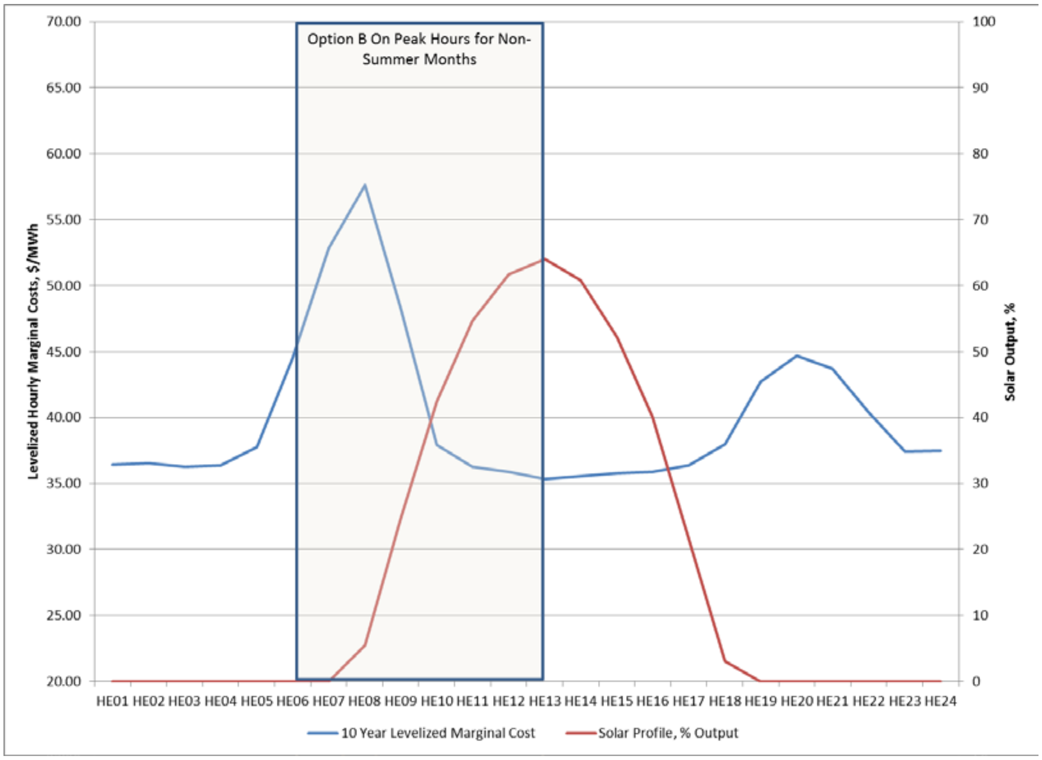
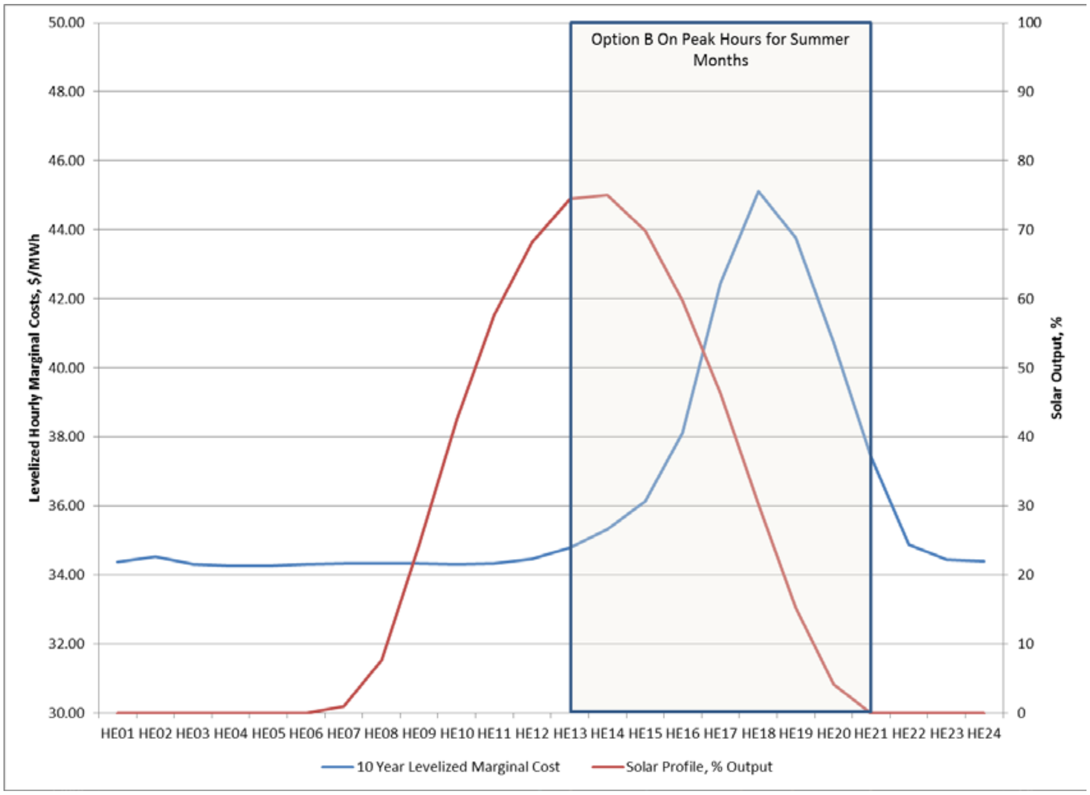


Figure 12: 10-Year Levelized DEP Projected Hourly Marginal Costs for July Overlaid with Average July Solar Shape



Q. HOW DO THE COMPANIES SUGGEST VALUING THE AVOIDED CAPACITY RATE IN THE CONTEXT OF A SOLAR-SPECIFIC QF RATE?

A. With respect to the capacity value of solar, the Companies would strive to align the capacity rate paid to solar with the amount of avoided capacity that solar resource will produce. As discussed by Witness Bowman, a large, utility-scale solar QF has unique characteristics that should be taken into account when considering the value of a solar-specific QF on the system outside of the standard QF rate offering. In particular, a solar QF is intermittent, it is non-dispatchable and, as such, not capable of following customer load. Importantly, its output profile is not coincident with system peak and, as I have mentioned, it is important to consider that during high demand periods, solar generation is ramping up when peak loads are declining and solar generation is falling off when customer demand is increasing. The culmination of these factors bring into question the appropriateness of ascribing significant capacity value to additional solar resources.

Q. DO YOU BELIEVE THE CHANGES YOU ARE SUGGESTING FOR LARGER QFS ARE RESPONSIVE TO NCSEA WITNESS JOHNSON'S SUGGESTION THAT THE "COMMISSION INITIATE STEPS TO PROVDE STRONGER, MORE PRECISE PEAK AND OFF-PEAK PRICE SIGNALS IN THE QF TARIFFS" TO ENCOURAGE SMALL POWER PRODUCERS TO "PROVIDE MORE OF THEIR POWER WHEN IT IS MOST VALUABLE, AND LESS WHEN IT IS LEAST VALUABLE?" [17]

A. Yes, as described above, the move towards using a solar-specific load profile to calculate negotiated QF rates along with potential changes in subsequent biennial avoided cost filings will provide price signals to QFs that reflect the specific characteristics of the QF as envisioned in PURPA.

[17] NCSEA Witness Johnson Testimony, at 197 – 98.

<u>LINE LOSSES IN CALCULATING STANDARD OFFER AVOIDED COSTS</u>

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS METZ'S SUGGESTION THAT IT MIGHT BE APPROPRIATE FOR DEP TO CONSIDER ELIMINATING THE LINE LOSS ADDER DUE TO REVERSE DISTRIBUTION TO TRANSMISSION POWER FLOWS IN FUTURE PROCEEDINGS?

A. The Companies agree with Witness Metz's suggestion that DEP consider eliminating the line loss adder in future biennial avoided cost proceedings. Further, as discussed above, and further described by Witness Bowman, the Companies may also evaluate this issue as part of the specific avoided cost characteristics for larger distribution-connected QFs.

<u>ANCILLARY COSTS IN CALCULATING STANDARD OFFER AVOIDED COSTS</u>

Q. ARE THE COMPANIES ADDRESSING THE NEED TO INCLUDE ANCILLARY COSTS ASSOCIATED WITH SOLAR QFS IN THIS FILING?

A. From a system operations perspective, ancillaries are an additional issue that needs to be addressed with larger QFs and are dependent on the characteristics of the specific QF in question. The Companies have not included ancillary costs in deriving the standard offer avoided energy rates in this docket.

However, an ancillary decrement in future biennial avoided cost proceedings, particularly in the context of a potential future solar-specific standard offer rate, may be appropriate.

III. ISSUES RELATED TO CALCULATING THE AVOIDED CAPACITY RATE

Q. WITNESS HINTON REFERENCES THE MAIN FACTORS INFLUENCING CHANGES IN THE COMPANIES' AVOIDED CAPACITY RATES FROM THE PRIOR RATES AS FILED IN SUB 140. DO YOU AGREE WITH HIS SUMMARY OF THE FACTORS THAT HAVE BEEN ADJUSTED?

A. I do agree with his summary of the factors that have been adjusted since the prior rates were filed in Phase 2 of Sub 140. In particular, the primary areas of adjustment that Witness Hinton refers to are:

i. Recognizing capacity value starting with the first year of actual need as shown in the Companies' respective IRPs;

ii. Changes to the Performance Adjustment Factor; and

iii. Changes to the weighting of capacity payments between the winter and summer peak seasons.

I will address concerns with changes to these components of the capacity rate valuation.

RECOGNIZING CAPACITY VALUE STARTING WITH THE FIRST YEAR OF ACTUAL NEED

Q. NCSEA WITNESS JOHNSON SUGGESTS THAT THE INCLUSION OF NO CAPACITY VALUE PRIOR TO THE UTILITY HAVING A NEED FOR CAPACITY IS DISCRIMINATORY TOWARD QFS. DO YOU AGREE WITH HIS ASSERTION? [18]

A. I do not. Rather, I agree with Public Staff witness Hinton. The inclusion of capacity value that is not actually avoidable results in an overpayment by consumers, in violation of PURPA. Witness Johnson mistakenly assumes that utilities "overbuild" resulting in excess capacity that is fully recoverable. He ignores the critical point that utilities are not overbuilt due to the addition of larger resources. Instead, when a larger unit is selected in a resource plan, it is because that resource is the most economic resource option for consumers. When building larger units, the Companies achieve economies of scale and operating efficiencies that provide a more economic and efficient solution for consumers as compared to smaller increments of generation. Small increments of generation that put the utilities at their minimum reserve margin targets in every year are not economically optimal for consumers (especially when the utilities cannot control and dispatch the generating resource being built). This is a popular misconception, often advanced by proponents of

[18] NCSEA Johnson Testimony, at 183.

small scale generation over central station utility-owned generation. I recognize that the IRP and Certificate of Public Convenience and Necessity ("CPCN") processes often result in periods of reserves in excess of minimum reserve targets. Importantly, this selection of a larger scale resource is done after a careful consideration of all the costs and benefits of smaller scale generation versus larger scale generation. As a result, a QF can only provide capacity value if there is an avoidable capital investment that can actually be deferred. Under any circumstance, it harms consumers to pay for capacity that is not actually avoided. Adhering to this basic principle does not discriminate against a QF but rather complies with PURPA's fundamental mandate to ensure consumers are not paying more for QF generation than they otherwise would utility generation.

PERFORMANCE ADJUSTMENT FACTOR (PAF)

Q. PRIOR TO ADDRESSING CONCERNS RAISED WITH THE PAF, PLEASE EXPLAIN WHAT A PAF IS AND HOW IT IMPACTS THE CAPACITY RATE FILED IN THIS PROCEEDING.

A. As I discussed in my prefiled direct testimony, the PAF is a simple multiplier that increases the avoided capacity rates paid by customers and received by the QF. The PAF included in the Companies' avoided capacity rates for small non-hydro QFs is 1.05. The 1.05 PAF represents a change from the PAF approved in Sub 140, which applied a 1.2 PAF to the avoided capacity rate.

Mathematically, applying a 1.2 PAF essentially increases the capacity payment made by the Companies' customers to QFs by 20% while a 1.05 PAF increases the capacity payment by 5%.

Q. DO YOU AGREE WITH THE RATIONALE FOR INCLUDING A PAF IN THE GENERIC CAPACITY PAYMENT TO QFS AS APPLIED IN NORTH CAROLINA?

A. Yes, I do. In general, I agree that a generic QF should not be held to a standard that requires 100% availability during peak hours to receive payments equivalent to the utility's full avoided capacity cost. Because all generating facilities, including the facilities deemed avoided through QF purchases, experience some degree of unavailability, applying a PAF is reasonable. I believe 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. As discussed later in my testimony, it is also 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. Both metrics, when properly applied, support a PAF of 1.05 as an appropriate availability adjustment to the QF capacity rate.

Q. WHAT DO YOU MEAN BY "RELIABILITY EQUIVALENT" TO THAT OF AN AVOIDED CT OR BASELOAD UNIT?

A. In simple terms, 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 the Companies to provide reliable service. Thus, the purpose of the PAF is to place the QF and avoided unit on the same basis in terms of their impact on system reliability.

Q. AS A SIMPLE MATTER OF COMPARISON, WHAT IS THE RELIABILITY OF A CT?

A. As I have previously testified, the appropriate measure of reliability for a CT peaking unit is the starting reliability. The Companies' CT fleet performs at a starting reliability of approximately **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]**. Although a PAF of **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** could be supported, my recommendation is to establish the PAF at 1.05 as a conservative measure to ensure that QFs receive fair capacity payment compensation. Further, it is my belief that no greater than a 1.05 PAF is warranted as 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.

Q. DO YOU BELIEVE THAT THE CT RELIABILITY EQUIVALENCE RATIONALE JUSTIFIES A 1.2 PAF, AS APPLIED TO SOLAR QFS UNDER THE RATES APPROVED IN SUB 140?

A. No. A PAF of 1.2 effectively means that a QF must only be available 83% of peak hours to receive payments equivalent to 100% of a utility's full avoided capacity costs. As explained in my testimony, a 95% availability equating to a 1.05 PAF is a more appropriate representation of a unit's availability as explained subsequently.

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESSES HINTON'S AND METZ'S SUPPORT FOR A PAF OF 1.16 WHICH IS BASED ON AN AVERAGE BASELOAD AVAILABILITY FACTOR OF 86.33%?

A. The Public Staff's focus on "availability" is appropriate, but their calculation has a critical flaw that leads to substantial overstatement of a just and reasonable PAF. Let me start by explaining a generator's "availability factor." The availability factor of a power plant is the amount of time that it is able to produce electricity over a certain period, divided by the amount of the time in the period. Apparently, the time period used in the Public Staff's calculations was based on annual data. Witnesses Hinton and Metz are testifying that the average availability factor for certain DEC, DEP, and DNCP baseload and intermediate units was about 86% during the period 2011-2016. Notably, the numerator of the availability factor reflects (i.e., is reduced by) the amount of time that a unit is out of service for planned maintenance. Thus, the annual availability factor measures how much a unit is available across an entire year which includes these planned outages such as nuclear refueling outages. Planned maintenance is typically conducted during off-peak shoulder periods when electricity demand is low. As such using the annual availability factor for the Companies' generating fleet is not relevant to the intended purpose of the PAF, which applies only to on-peak periods. By definition, off-peak periods have very low loss of load risk even with the planned maintenance outages. Of greater importance, QFs do not have to produce a single MWh in off-peak hours to receive their full capacity payment. While conversely, Public Staff is using off-peak planned maintenance from utility generation to effectively increase the proposed PAF they are recommending for QFs. By way of example, that would imply that an acceptable operational practice would be to schedule a nuclear unit refueling outage during peak demand periods. Obviously, that is not representative of prudent utility operating practice. In fact, the Companies strive to take outages, planned or not, during lower load or off-peak periods when capacity is not needed. In summary, any availability metric used to support a PAF must focus solely on the peak availability and not annual availability. It is simply mathematically incorrect to base a PAF on annual availability of utility generation which includes off-peak outages as a measure of on-peak performance for a QF

Q. WHAT WOULD THE IMPLICATIONS BE IF THE COMPANIES' GENERATING FLEET OPERATED AT THE ON-PEAK PERFORMANCE THAT THE PUBLIC STAFF RECOMMENDS FOR SETTING A PAF FOR QFS?

A. Since utility reserve margins are based on on-peak availability of greater than 95%, imposing an assumed 86% peak availability would result in a significant increase in the Companies' reserve margin requirement and significant increase in costs to consumers to build or buy greater amounts of capacity in order to provide reliable service.

Q. NCSEA WITNESS JOHNSON CONTENDS THAT UTILITIES ARE NOT HELD TO THIS HIGH STANDARD OF 95% AVAILABILITY. HOW DO YOU RESPOND?

A. Clearly the Companies manage their generation fleets to achieve a very high level of on-peak reliability. For example, the nuclear fleet, in the context of a utility fuel case, has the burden of proof to demonstrate high availability relative to industry peers as a matter of prudence. If you adjust for off-peak refueling outages, as described above, and solely examine the fleet's performance during peak summer and winter months you would see peak availability well in excess of 95%. Furthermore, consider that DEC and DEP combined operate over 36,000 MWs of capacity. 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 5,000MW of generation unavailable during any given peak hour. With over 25 years of utility experience, I find it difficult to assume that Commission would find it acceptable for the Companies to average 5,000 MW of unit outages over the entire winter and summer period.

Q. IF THE COMMISSION BELIEVES THAT THE PAF SHOULD BE BASED ON SYSTEM AVAILABILITY, AS THE PUBLIC STAFF RECOMMENDS, AS OPPOSED TO AVAILABILITY OF THE CT, WHICH SERVES AS THE BASIS FOR THE CAPACITY PAYMENT UNDER THE PEAKER METHOD, WHAT IS THE APPROPRIATE AVAILABILITY METRIC THAT SHOULD BE USED?

A. If the Commission believes that the PAF should be based on a system availability metric, then it should be based on a metric that represents the reliability of the system during peak demand periods, and I would recommend using the Equivalent Forced Outage Rate ("EFOR"). EFOR represents the reliability of a unit or generating fleet during periods between planned maintenance intervals which means that it is a better indicator of the reliability of the unit or fleet during peak demand periods when performance is critical.

Q. HAVE YOU CALCULATED A SYSTEM WEIGHTED AVERAGE EFOR VALUE FOR THE COMPANIES?

A. Yes, a system weighted average EFOR value was calculated as part of the 2016 resource adequacy studies to give an idea of the total system EFOR performance. The annual system weighted average EFOR for DEC was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and for DEP was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. IF AN ON-PEAK EFOR WAS ADOPTED AS THE BASIS FOR ESTABLISHING THE PAF, WHAT VALUE OF PAF WOULD YOU SUPPORT?

A. Similar to the CT starting reliability data, the EFOR data from the 2016 resource adequacy studies again supports a PAF less than, and certainly no greater than, 1.05.

Q. WHAT IS YOUR RESPONSE TO NCSEA WITNESS JOHNSON'S ASSERTION THAT REDUCING THE PERFORMANCE ADJUSTMENT FACTOR TO 1.05 WOULD HAVE THE EFFECT OF REQUIRING A QF TO PRODUCE AT FULL CAPACITY DURING 95% OF THE ON-PEAK HOURS TO RECEIVE FULL AVOIDED CAPACITY COSTS?

A. I agree with Witness Johnson's statement that a PAF of 1.05 would require a QF to operate 95% of on-peak hours to receive a full capacity payment. I further recognize that the rates filed are generic rates applying to all QFs, with origins dating back to non-dispatchable baseload gas co-generators. Notably, if a solar QF, or any other QF for that matter, was truly dispatchable, then the Companies would be open to a demand rate that would allow that dispatchable QF to receive capacity payments consistent with other dispatchable capacity resources the Companies purchase outside of PURPA. The dispatchability allows these resources to receive full capacity payments without producing in 95% of on-peak hours. It is the very non-dispatchable nature of QF power that requires the QF to operate across the peak to receive a full capacity payment. If the QF were dispatchable, capacity could be paid based upon dispatch performance like other generation outside of PURPA. This is a key point that is often lost in the comparison of non-QF capacity and QF capacity. In fact, PURPA specifically envisions issues like intermittency and dispatchability to be factored into the rate structure and valuation.

Q. EXCLUDING APPLICATION OF THE PAF, APPROXIMATELY WHAT PERCENTAGE OF THE AVOIDED CT COST WOULD A TYPICAL SOLAR QF BE COMPENSATED FOR BASED ON THE COMPANIES' RATES IN THIS DOCKET?

A. As I stated in my direct testimony, given the broad definition of on-peak hours in the current rate structure, under Option B of Schedule PP, a typical solar facility would be compensated for avoiding approximately 40% of its nameplate capacity in equivalent avoided "peaker" capacity while only providing an actual capacity value of 5% or less. This means that each MW of QF solar would be compensated for almost 40% of the cost of a CT while providing only 5% of the capacity value that a CT would provide.

Q. DO YOU BELIEVE THAT YOUR RECOMMENDATION TO ADJUST THE PAF FROM 1.2 TO 1.05 IS FAIR TO THE QFS AND TO THE COMPANIES' CUSTOMERS?

A. Yes, I do. While the precise method and basis for calculating a PAF can be debated, the reliability of a CT and the reliability of the Companies' entire generating fleet both support a PAF of no greater than 1.05. A PAF of 1.05 appropriately aligns the capacity payment adder to the correct reliability metric and thus fairly compensates a generic standard offer QF for the capacity value that they provide under the peaker method. Further, I believe the adder is reasonable and provides just and fair rates to the Companies' electricity consumers.

SEASONAL WEIGHTING

Q. HAVE ANY INTERVENORS QUESTIONED THE COMPANIES' CHANGE IN SEASONAL CAPACITY VALUE ALLOCATION FROM 60/40 SUMMER/WINTER TO 80/20 WINTER/SUMMER?

A. Yes, based on testimony in this docket as well as comments in Docket No. E-100, Sub 147, there appears to be some misunderstanding regarding the fundamental findings and conclusions of the resource adequacy studies presented in the Companies' 2016 Biennial IRPs, the need for the Companies' shift to winter capacity planning, and the associated seasonal capacity value allocation. Although it is not entirely clear, intervenors seem to associate the need for winter capacity planning with winter peaking. For example, Witness Hinton states:

> As the Public Staff stated in its comments in the 2016 IRP Proceeding, the shift of DEC and DEP from summer to winter peaking should not diminish consideration of the summer peak, which remains significant. . . . Until a pattern of winter peaks is better understood and there is

> more confidence that the Company is a winter peaking utility, shifting to a predominantly winter-centric paradigm may be premature. [19]

Q. WITNESS HINTON'S STATEMENT ABOVE REFERENCES THE PUBLIC STAFF'S COMMENTS IN THE 2016 IRP PROCEEDING (DOCKET NO. E-100, SUB 147). WHAT COMMENTS DID THE PUBLIC STAFF MAKE IN THE 2016 IRP PROCEEDING REGARDING WINTER PEAKING VERSUS WINTER CAPACITY PLANNING?

A. The Public Staff's recent comments in the 2016 IRP proceeding provide:

> DEP and DEC's shift from being summer peaking systems to a winter peaking systems means that their reserve margins are designed to meet the winter peak. [20]

Q. IS THE ASSOCIATION OF WINTER PEAKING AND WINTER CAPACITY PLANNING CORRECT?

A. It is not.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY WINTER CAPACITY PLANNING.

A. As I explained in my direct testimony, the load and resource balance has changed drastically in the past two-to-three years, driven primarily by the high penetration of solar resources as well as the significant load response to recent cold weather. Furthermore, winter peak demands are more sensitive to weather volatility than summer peak demands. Despite the fact that solar

[19] Public Staff Hinton Testimony, at 25-26.
[20] Comments of the Public Staff, 2016 Biennial Integrated Resource Plans and Related 2016 REPS Compliance Plans, at 42 Docket No. E-100, Sub 147 (filed Feb. 17, 2017)

output is declining going into the afternoon summer peak, solar resources still contribute significantly more to the summer afternoon peak periods than they contribute to the winter morning peaks. Even if the weather normal peak is in the summer DEC and DEP must still "plan" based on a winter peak reserve margin criteria as a result of existing and anticipated solar on the system. Definitively, 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. This was described on page 31 of the 2016 DEC Biennial IRP and page 32 of the 2016 DEP Biennial IRP. The transition to winter capacity planning, via use of a winter reserve margin target is essential to ensure that adequate reserves will be available throughout the year as required to provide acceptable resource adequacy.

Q. IN RECENT YEARS, HAVE THE DEC AND DEP ANNUAL PEAKS TYPICALLY OCCURRED IN THE SUMMER OR WINTER?

A. As shown in Figures 12 and 13 below, during the last five years (2012-2016), DEC's annual peak has occurred in the winter in 2 out of the 5 years and DEP's annual peak has occurred in the winter in 4 out of the 5 years.

<u>Figure 12: Historical DEC Winter and Summer Peaks</u>

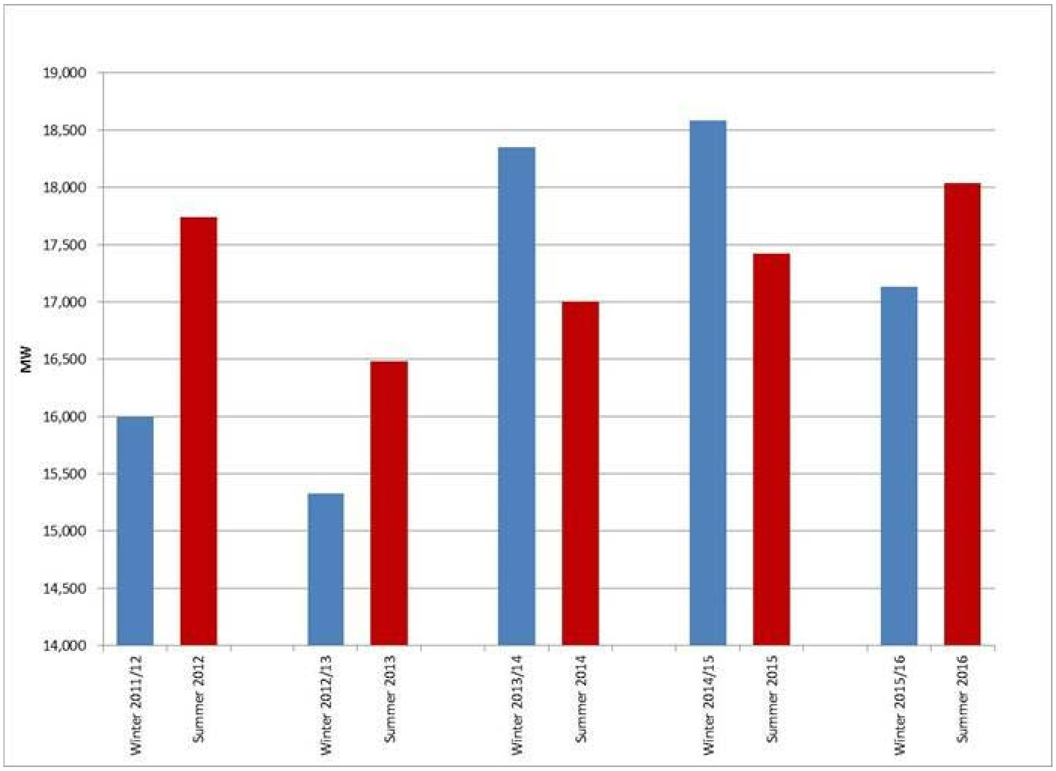
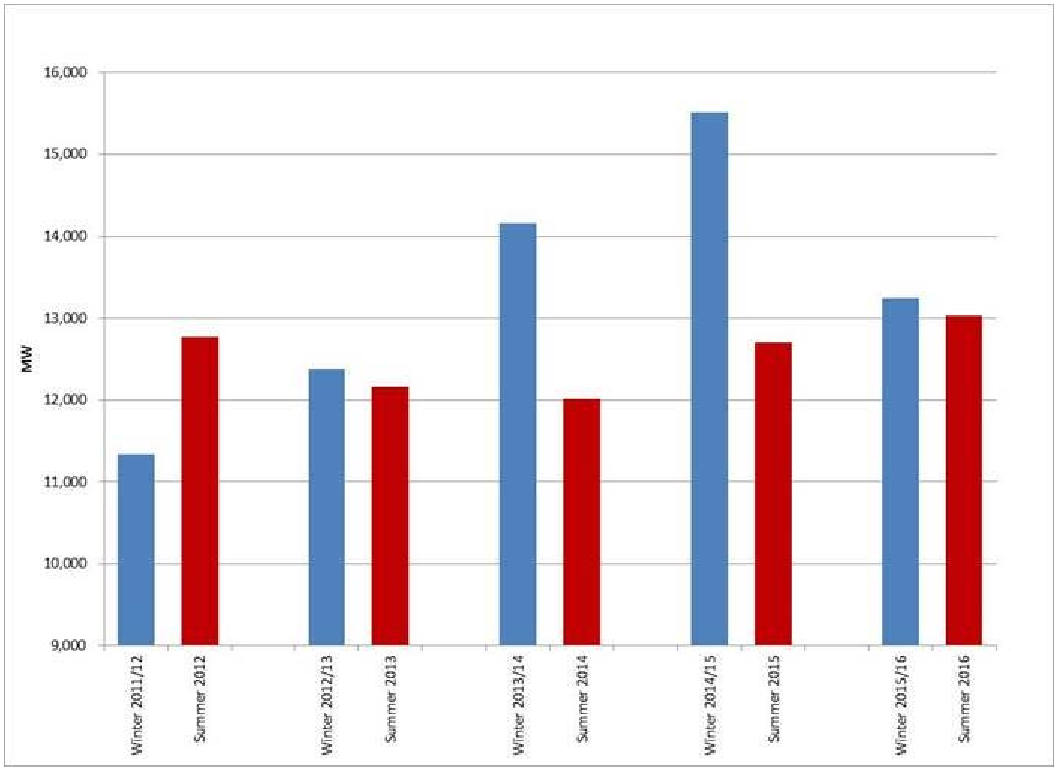


Figure 13: Historical DEP Winter and Summer Peaks



Q. ON A PROJECTED BASIS, DO THE COMPANIES EXPECT THEIR ANNUAL PEAK DEMANDS TO OCCUR IN THE SUMMER OR WINTER?

A. Based on the Companies' 2016 IRPs, the DEP annual peak is expected to occur in the winter for each year of the planning horizon. However, DEC is summer peaking until around 2027, at which time the annual peak is projected to occur during the winter. For both Companies, the winter peaks are projected to grow a greater rate than summer peaks. Notably, the Companies have experienced significant load response to recent winter weather and are continuing to refine the summer and winter peak demand forecasting process as part of the overall integrated resource planning process.

Q. DO THE COMPANIES AGREE WITH WITNESS HINTON'S STATEMENT THAT DEC AND DEP WERE MODELED AS WINTER PEAKING IN THE 2016 RESOURCE ADEQUACY STUDIES?

A. Witness Hinton states, "The third adjustment was to change the seasonal weighting of capacity for summer and non-summer months based on DEP's new reserve margin study that models the Company as winter peaking." [21] However, as I previously stated, based on the 2016 Biennial IRP, DEP's projected winter peaks exceed summer peaks; however, DEC's summer peaks exceed winter peaks until around 2027. The resource adequacy studies were based on study year 2019, when DEP is winter peaking and DEC is summer peaking. Irrespective of summer versus witner peaks, the resource adequacy study results clearly showed the need for both Companies to shift to winter capacity planning as a result of the impact of solar generation.

Q. NCSEA WITNESS JOHNSON PRESENTS TESTIMONY REGARDING HISTORIC HOURLY LOAD DATA FOR DEC AND DEP FOR THE PERIOD 2006-2015. HOW DO YOU RESPOND TO HIS ASSERTIONS?

A. Witness Johnson states, "The hourly load data indicates that approximately 86.5% of the most extreme system peaks (at or above 99% of the annual coincident system peak) occurred during the months of June through September, while the remaining 13.5% occurred during the months of

[21] Public Staff Hinton Testimony, at 16.

December, January and February. None of these extreme peaks have occurred during any other months."[22] He concludes that "This data is entirely inconsistent with Duke's proposal to allocate 80% of the capacity costs to a broadly defined non-summer period that starts in October and ends in May." [23]

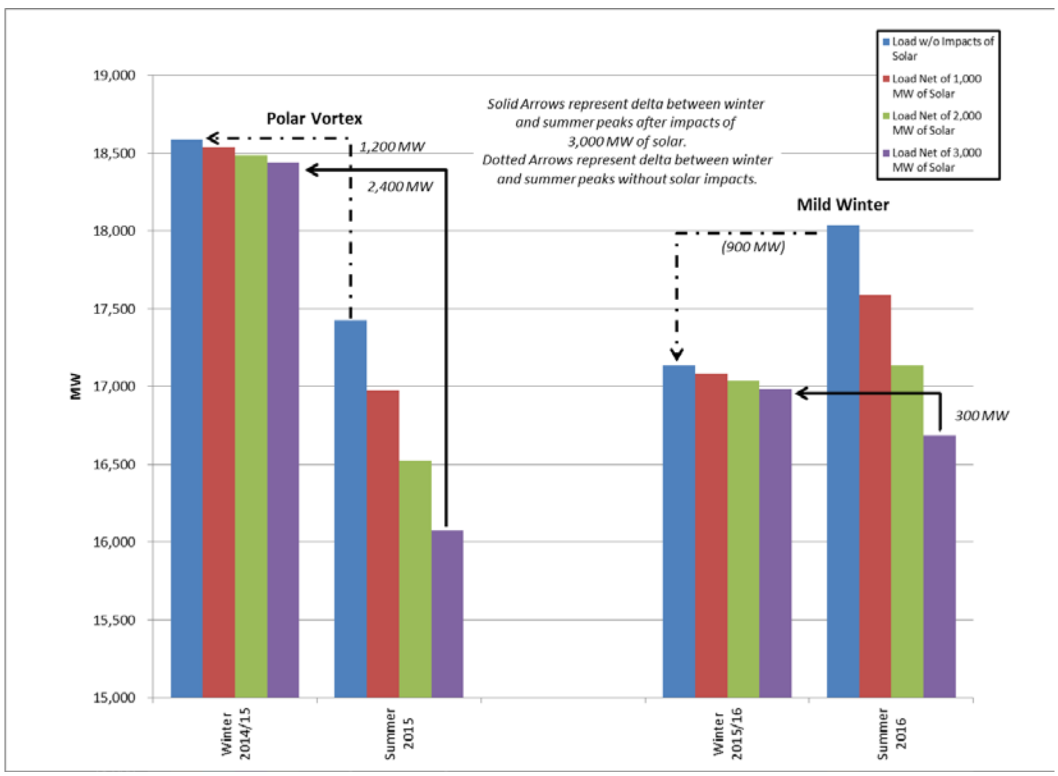
As Witness Johnson points out, the Companies do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has some energy contributions as compared to winter where very little solar is available at time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. Further, there is greater uncertainty in winter loads as demonstrated during recent winter periods, and these severe winter load and resource conditions have the greatest impact on system reliability and Loss of Load Expectation ("LOLE").

The Companies consider solar resources as supply-side resources in the IRP process. However, for purposes of better understanding the impact of solar on the Companies' summer and winter reserve margins it may be easier to think of solar capacity as a reduction to load. Consider Figure 14 below which shows the relationship of summer versus winter peaks for DEC for a cold winter (2015) and a mild winter (2016). The figure shows the impact on summer and winter peaks for 1,000 MW, 2,000 MW, and 3,000 MW blocks of hypothetical solar capacity. For the 2015 cold winter year, the Figure

[22] NCSEA Witness Johnson Testimony, at 199.
[23] NCSEA Witness Johnson Testimony, at 200.

shows that the winter peak was about 1,200 MW greater than the summer peak. However, 3,000 MW of solar capacity would result in a winter peak that exceeded summer peak by about 2,400 MW. For the 2016 mild winter year, the summer peak exceeded the winter peak by about 900 MW; however, 3,000 MW of solar capacity would actually result in a winter peak that exceeds the summer peak by about 300 MW.

<u>Figure 14: DEC Historical Peaks including Impacts of Solar Penetration</u>



The Figure demonstrates the dramatic impact that high penetrations of solar can have on summer versus winter loads (net of solar). This impact on peak demands can also be thought of as the impact on reserve capacity which is the primary driver for the Companies' need to shift to winter capacity planning.

Thus, Witness Johnson only evaluated historic load data and did not consider reserve capacity, which is key to understanding loss of load risk. As I stated, the most severe load and resource conditions typically occur in the winter and these events have the greatest impact on reliability. High solar penetration levels exist today, and evaluating only load data for past time periods is meaningless without consideration of the impact of solar on net reserves. Witness Johnson's argument should be rejected.

Q. IF SOLAR MAKES SIGNIFICANT CONTRIBUTIONS DURING THE SUMMER, DOESN'T THAT MEAN THAT SOLAR HAS A CAPACITY VALUE?

A. Existing solar does have capacity value and the impact of solar was captured in the resource adequacy studies that were conducted in 2016. In addition, solar capacity led to the shift to the Companies now planning for a winter reserve margin target that they must now maintain to ensure reliable service to our customers. However, incremental solar additions have little impact on the Companies' future resource needs for maintaining adequate winter reserve capacity. Simply stated, a balanced system only requires so much of a given capacity type. Like any other generation source in the utility's resource mix, the capacity value of incremental solar is less valuable than existing solar.

Q. THE PUBLIC STAFF RECOMMENDS ADJUSTING THE SEASONAL WEIGHTING TO 40% FOR SUMMER AND 60% FOR NON-SUMMER. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The Public Staff did not directly challenge the rationale of using the loss of load risk in the Companies' resource adequacy studies as the basis to support the seasonal weighting; however, they did express concerns with the seasonal weighting factors of 80/20 winter/summer. Witness Hinton explains the Public Staff's position as:

> . . .the Public Staff does not believe that the significant shift of avoided capacity values to the winter periods should be made at this time. As the Public Staff stated in its comments in the 2016 IRP Proceeding, the shift of DEC and DEP from summer to winter peaking should not diminish consideration of the summer peak, which remains significant. Additionally, Duke is continuing to refine its load forecasting capabilities to better understand the growth and impact of DEC's and DEP's winter and summer peaks. Until a pattern of winter peaks is better understood and there is more confidence that the Company is a winter peaking utility, shifting to a predominantly winter-centric paradigm may be premature. [24]

As I have discussed, the Public Staff seems to base its reasoning incorrectly on the relationship between the Companies' summer versus winter peak demands. While it is true that the Companies have experienced significant peak loads in recent winter periods, and that the Companies continue to refine their load forecasting capabilities and evaluate the growth and impact of winter and summer peak demands, the load forecast (or summer versus winter peaking) is not a primary driver for the significant shift in seasonal loss of load risk. As previously discussed, the primary drivers for the seasonal shift

[24] Public Staff Hinton Testimony, at 25.

in LOLE are the high penetration of solar resources and winter load variability. Both factors can impact actual reserve levels and the resulting LOLE. Additional solar will only exacerbate the winter LOLE concentration. The 40% summer and 60% non-summer seasonal weighting recommended by witness Hinton would send the wrong price signal to developers, and thus the Commission should reject the Public Staff's recommendation.

Q. SACE WITNESS VITOLO EXPRESSES CONCERN THAT THE RESOURCE ADEQUACY STUDIES OVEREMPHASIZED THE "ATYPICAL" RECENT WEATHER EXPERIENCED DURING THE 2014 AND 2015 WINTERS. WHAT IS YOUR RESPONSE TO WITNESS VITOLO ON THIS ISSUE?

A. Witness Vitolo states that "… because including all 36 years of historical weather data the study team already had would have both ensured the inclusion of the Polar Vortex years without overly emphasizing them, something including only five years of data did." [25] Witness Vitolo seems to be under the mis-impression that the resource adequacy studies only included the past five years of weather and load data in the analysis. This is not true. In simple terms, the studies included the last five years of weather and load data to develop weather and load relationships that could be applied to all 36 historic weather years (1980-2015) that were included in the study. The resource adequacy studies purpose was to project what the hourly loads would

[25] SACE Witness Vitolo Testimony, at 36.

be for the study year 2019 if the same weather from a historic year was experienced. This modeling was done for all 36 historic weather years, not just the last five.

Load uncertainty due to weather is a key driver of resource adequacy study results. The Companies view the analytics and results produced by Astrape as reasonable and appropriate for utiity planning, and Witness Vitolo's comments should be rejected.

Q. SACE WITNESS VITOLO ALSO EXPRESSES CONCERNS THAT BASING THE SEASONAL ALLOCATION ON RESULTS FROM STUDY YEAR 2019 MAY NOT BE REPRESENTATIVE OF OTHER YEARS. HOW DO YOU RESPOND?

A. As Witness Vitolo's notes, the results from the resource adequacy studies conducted in 2016 may not be applicable to all future years since conditions may change that could impact system reliability. The potential for future changes was precisely why the Companies chose to conduct new studies in 2016 in order to account for the impact of significant levels of solar capacity that did not exist and were not foreseen at the time of the 2012 study, as well as the significant response to winter weather that was experienced in the years following the 2012 study. Further, the Companies will continue to commission new studies as significant changes occur that may impact study assumptions and results.

The recommended 80/20 winter/summer weighting reflects the Companies' best estimates at this time. As I have noted, additional solar will only shift a greater concentration of LOLE to the winter period.

Q. HAVE THE COMPANIES ASSESSED THE IMPACT OF THE CHANGE IN THE SEASONAL WEIGHTING TO 80% WINTER / 20% SUMMER TO SOLAR QFS?

A. Yes, we have. This situation is similar to the issue with solar QFs receiving significantly higher capacity payments in relation to the capacity value they provide due to the broad range of on-peak hours defined in Option B. The Companies have determined that the net impact on capacity payments paid to solar QFs as a result of changing the seasonal weighting to 80/20 winter/summer (i.e. 80/20 non-summer/summer) is negligible. Depending on whether the DEC or DEP solar profile is used, the impact on capacity payments is about +/- 1%. Thus, while the change in seasonal weighting is significant, the impact on avoided capacity payments to solar QFs in this docket is quite small. Finally, for a baseload QF, such as a cogenerator, there would be no impact on capacity payments.

Q. IF SOLAR PROVIDES A 5% CAPACITY VALUE RELATIVE TO ITS NAMEPLATE RATING, TO WHAT EXTENT ARE THE COMPANIES' STANDARD OFFER AVOIDED CAPACITY RATES DESIGNED TO COMPENSATE FOR THE NAMEPLATE CAPACITY?

A. As I have noted, given the broad definition of on-peak hours in the current Schedule PP Option B rate structure, a typical solar facility would be compensated for avoiding approximately 40% of its nameplate capacity in equivalent avoided "peaker" capacity while only providing an actual capacity value of about 5%. This means that each MW of QF solar would be compensated for almost 40% of the cost of a MW of a CT beginning with the first need for new capacity while providing only 5% of the capacity value that a CT would provide. This result is also prior to any PAF adjustment.

Q. DOES THE CHANGE IN SEASONAL CAPACITY VALUE ALLOCATION TO 80/20 WINTER/SUMMER HAVE A SIGNIFICANT IMPACT ON THE CAPACITY PAYMENT TO SOLAR FACILITIES UNDER THE COMPANIES' RATES IN THIS PROCEEDING?

A. No, it does not.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of	)	
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	)	**REBUTTAL TESTIMONY OF JOHN SAMUEL HOLEMAN III ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Samuel Holeman III. My business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as the Vice President of the System Planning and Operations Department for Duke Energy Corporation ("Duke Energy"). In that capacity, I oversee the planning and operations for Duke Energy's regulated electric utilities' electrical systems, including Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies").

Q. HAVE YOU SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I pre-filed direct testimony on behalf of the Companies on February 21, 2017, in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to Public Staff Witness Dustin R. Metz's testimony and recommendations concerning system operations, safety, reliability, and regulatory compliance in regards to the current, upcoming, and future North American Electric Reliability Corporation ("NERC") Reliability Standards. As recommended by Witness Metz, my rebuttal testimony seeks to further inform the Commission of the adverse impacts to reliable operations, risks of NERC non-compliance, and diminished operational flexibility and situational awareness, especially on the DEP system, because of the very high levels of energy being intermittently injected into and withdrawn from the system by solar qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA").

In connection with the safety and reliability risks addressed by the more robust BAL-002 standard, to be effective January 1, 2018, my rebuttal testimony responds to Public Staff Witness Metz's discussion of the Joint Dispatch Agreement ("JDA")[1] between DEC and DEP. Specifically, I explain the inherent limitations of the purely economic role of the JDA and the non-firm, curtailable transmission path between DEC and DEP underlying the JDA's economic transfer capability.

I also respond to Public Staff Witness Metz's discussion about potential future "system emergency" curtailments of QFs on the DEP system, and explain the high likelihood of operational curtailments of QFs that will be required in real time to ensure compliance with NERC's Reliability Standard requirements and avoid real risks to reliable electric service, principally as additional QFs continue to come online.

Finally, I rebut North Carolina Sustainable Energy Association ("NCSEA") Witness Ben Johnson's dismissive statement that the Companies' system operations experience and the future safety, reliability, and regulatory compliance challenges demonstrated in my direct testimony are merely "growing pains."[2] Every electric system has physical limitations as to the

[1] Joint Dispatch Agreement, effective July 2, 2012, between Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (formerly known as Carolina Power & Light Company) on file with the Federal Energy Regulatory Commission ("FERC") in Docket No. ER12-1338-000.

[2] NCSEA Johnson Testimony, at 209.

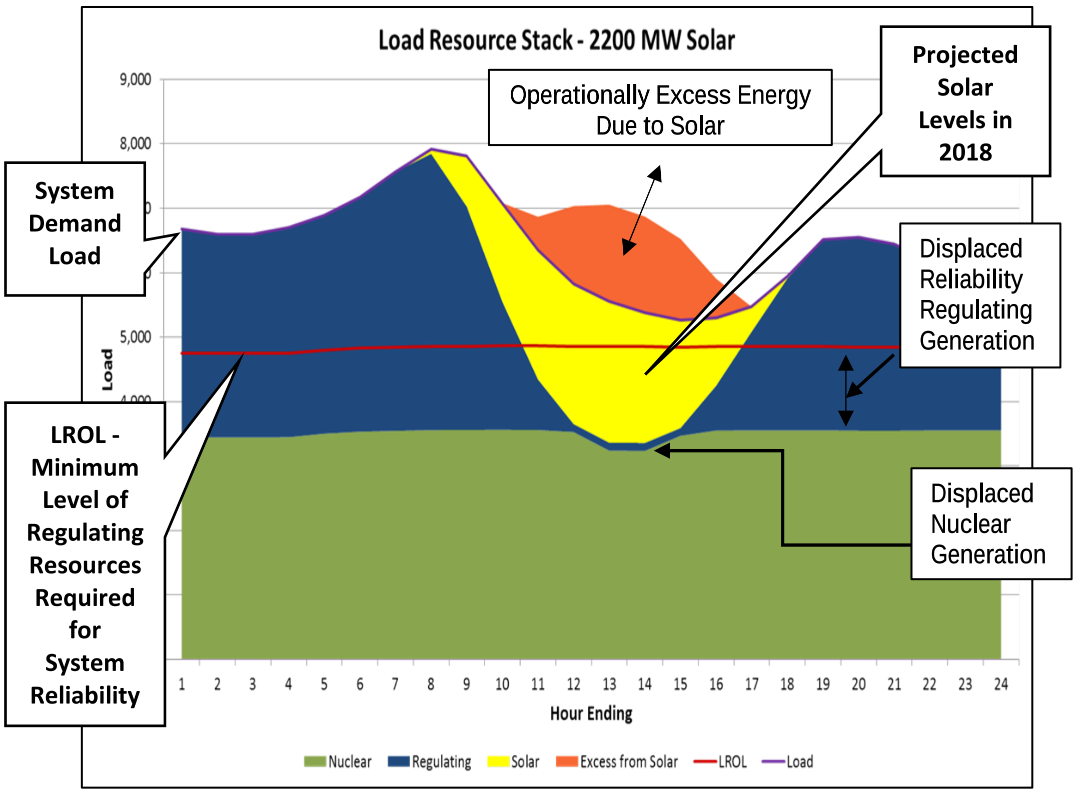
amount of any resource that it can safely and reliably accommodate. As a system operator, I am agnostic as to the type of generation technology connected to the system, as long as I can prudently provide reliable and secure service to our customers.

Q. PLEASE BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY.

A. My direct testimony informed the Commission of the impacts to system reliability and risks of non-compliance with NERC's Reliability Standards due to the operationally excess energy that is being injected into the DEP balancing authority ("BA"). I explained that QFs inject energy into the BA without any commitment, and without day-ahead or intra-day coordination with the BA, and therefore, are making "unscheduled" energy injections into the BA. These unscheduled QF energy injections are "unconstrained" by dispatch control due to PURPA's limitations, except under contractual provisions for "system emergency" conditions. I also demonstrated how the real-time balancing of the DEP BA has become volatile due to large and uncertain swings of unscheduled, intermittent solar QF energy injections into the BA.

I explained that the BA operator must select a Security Constrained Unit Commitment that is necessary to reliably provide firm native load service in the DEP BA and meet NERC Reliability Standards. As explained in my direct testimony, the Security Constrained Unit Commitment's Lowest Reliability Operating Level ("LROL"), *below which the BA cannot reduce operational output*, must be retained through the mid-day valley of the demand curve each day to provide for: (i) frequency regulation; (ii) resource availability to meet the evening peak demand; as well as (iii) resource availability to meet the next morning's peak demand, which is generally higher than the previous evening's peak demand for winter load patterns. The "LROL" is illustrated in Figure 1 by the red line (which replicates Figure 9 from my direct testimony).

Figure 1



I explained that the DEP BA is currently experiencing operationally excess energy during certain hours caused by the very high levels of QF capacity additions. As illustrated above, during these QF-caused over-generation events, although the BA's actual load demand is above the LROL (i.e. no system over-generation), the unscheduled and unconstrained QF energy injections are causing "net" demand to drop below the LROL. This causes operationally excess QF energy due to the operationally excess QF capacity additions. As additional QFs request to interconnect and inject energy into the system under PURPA, the DEP BA is increasingly exposed to significant risks to reliable electric service.

Q. WHAT WILL BE THE SOLAR QF PENETRATION LEVELS ON THE DEP BA BY EARLY 2018?

A. As of the time of my rebuttal testimony, approximately 1,552 MWs of solar QFs are interconnected and injecting energy into the DEP BA, including North Carolina, South Carolina, and behind-the-meter wholesale interconnections. There are approximately 831 MWs of additional solar QFs already under construction that are expected to become operational by early 2018. This means that solar QF penetration in the DEP BA will soon be at or greater than 2,200 MWs – *functionally, making these intermittent facilities the largest aggregate generator on the DEP BA.*

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS METZ'S CONCLUSION THAT A VIOLATION OF MANDATORY RELIABILITY STANDARDS, SUCH AS THE BAL-001, 002, AND 003 STANDARDS OVER THE PERFORMANCE MEASUREMENT PERIOD (15-30 MINUTES), COULD "DAMAGE GENERATORS, LEAD TO LOAD SHEDDING, AND, IN THE WORSE CASE SCENARIO, COLLAPSE THE SYSTEM ACROSS THE ENTIRE

EASTERN INTERCONNECTION, NOT JUST WITHIN DEC'S OR DEP'S BALANCING AUTHORITY AREAS"? [3]

A. Yes, I do. Public Staff Witness Metz correctly recognizes that compliance with NERC Reliability Standards, specifically including the BAL-001, 002, and 003 standards discussed in my direct testimony is mandatory, *because compliance with these standards is essential to ensuring reliability*, not only in the DEP and DEC BAs but across the entire Interconnection.

Public Staff Witness Metz also is correct that "[c]ontinued growth in unconstrained and non-dispatchable generation will only serve to exacerbate the current system challenges."[4] I am especially concerned about the adverse impact the excessive quantities of QF energy injections into and withdrawal from the DEP BA is having on DEP's capability to meet its obligation to provide essential reliability services.

As I discuss below, Public Staff Witness Metz is correct in noting that NERC is continually reviewing and revising its Reliability Standards to address evolving reliability concerns. These revised standards usually require the BA to plan for and meet more robust operating practices. For example, the BAL 002-2 standard that will be subject to enforcement starting January 1, 2018, will apply more rigorous operating contingencies and will expand the risk of violating the BAL 002 standard on both the DEP and DEC BAs.

[3] Public Staff Metz Testimony, at 4-5.

[4] Public Staff Metz Testimony, at 9.

Q. WHAT ARE ESSENTIAL RELIABILITY SERVICES?

A. Essential reliability services are elemental reliability building blocks integral to providing reliable electric service to customers and protecting system equipment, and must be provided regardless of the BA's resource mix. Observing the potential for variable energy resources to impact necessary reliability services delivered by large rotating mass synchronous generators essential for reliable electric system operations, NERC established the Essential Reliability Services Task Force in June 2014, to examine these essential reliability services and develop standards for their application.

As noted above, essential reliability services are provided by designated network and contingency resources that have synchronous, load-following response capabilities. The components of essential reliability services are: (i) voltage support; (ii) system inertia; (iii) ramping; and (iv) frequency support. In connection with my discussion of the BAL-001, 002, and 003 standards in my direct testimony, I discussed impacts to ramping and frequency support due to the very high levels of QF energy injections. Essential reliability services are critical to reliable BA operations, therefore, they are measured and monitored to comply with NERC requirements so that operators and planners are aware of the changing characteristics of the BA and can make informed decisions to operate the BA in a reliable manner.

In response to Public Staff Witness Metz's recommendation that I explain the impacts of the upcoming BAL-002-2 standard, I will briefly elaborate on the impacted essential reliability services.

Q. ARE THE HIGH LEVELS OF PURPA FACILITIES, ESPECIALLY SOLAR QFs IN THE DEP BA, CHALLENGING DEP'S CAPABILITY TO PROVIDE ESSENTIAL RELIABILITY SERVICES?

A. Yes they are. The DEP BA is currently operating with reduced operational flexibility and diminished situational awareness under normal conditions. Operational flexibility and situational awareness will further diminish as more QFs become operational and inject even more unscheduled and unconstrained energy into the BA. In addition to being variable, intermittent, unconstrained, and unscheduled in nature, solar QF energy injections into the BA are also "non-conforming to load," meaning that solar energy injections do not support the BA's peak demands for most of the year, neither for the morning peak nor for the late day peak for fall, winter, and spring load shapes.

Operating with diminished flexibility during normal conditions places the BA under even greater risks of NERC violations and greater risks to reliable electric service during abnormal conditions. At current levels of solar QF energy injections, DEP is already experiencing "exceedances" of NERC's Balancing Authority ACE Limit ("BAAL"), as I describe later in my rebuttal testimony. As operating conditions become more rigorous under new standards going forward, such as under the new BAL-002-2 standard, non-compliance risks will also increase.

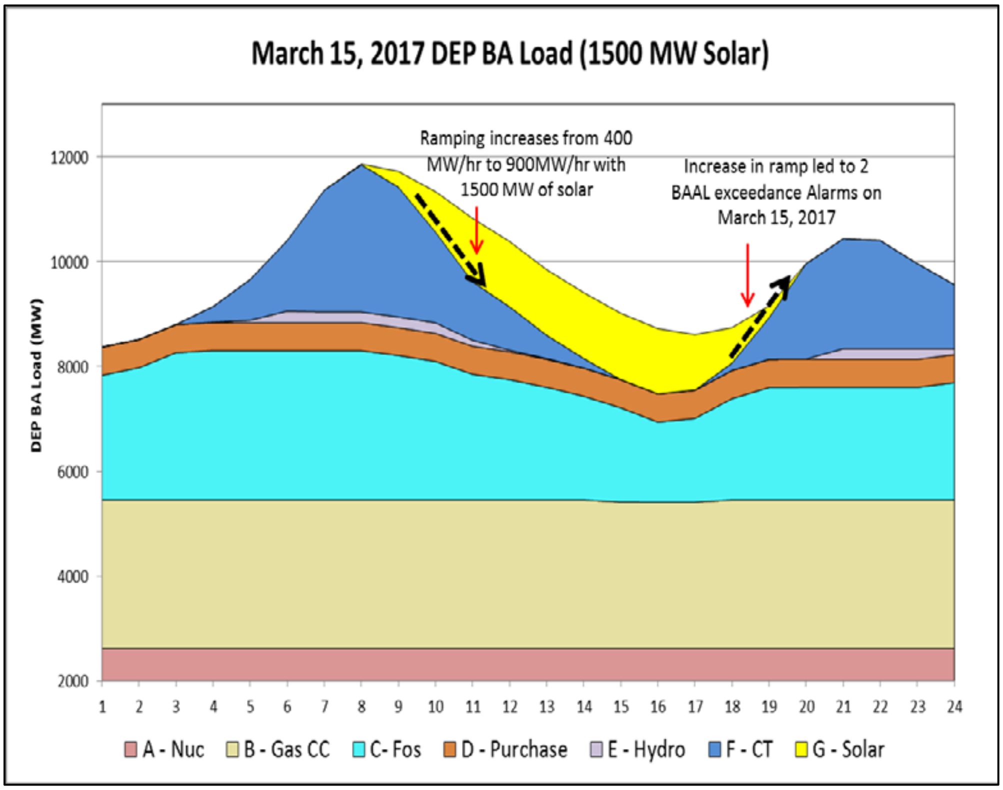
Q. AS BACKGROUND TO ADDRESSING PUBLIC STAFF WITNESS METZ'S REQUEST THAT THE COMPANIES PROVIDE ADDITIONAL DETAIL REGARDING THE NEW BAL-002-2 STANDARD AND ITS EFFECT ON SYSTEM OPERATIONS, PLEASE PROVIDE AN EXAMPLE OF NERC BAAL "EXCEEDANCES" IN THE DEP BA DUE TO ITS HIGH LEVELS OF SOLAR QFS.

A. As mentioned on page 28 of my direct testimony and discussed by Witness Metz on pages 4-5 of his testimony, DEP and DEC must comply with all applicable NERC Reliability Standards, including the BAL-001, BAL-002, and BAL-003 standards. The BAL-001 standard requires Interconnection steady-state frequency within defined limits by balancing real power demand and supply resources in real time and, as needed, to take action to support reliability. Prior to July 1, 2016, BAL-001-1, the then-effective standard, required averaging the BA's Area Control Error ("ACE")[5] over each 10-minute period *in the month* and at least 90% of those 10-minute average ACE measurements each month had to be less than or equal to an ACE limit, L_{10}. In contrast, the current BAL-001-2 standard requires BAs to manage their ACE to within an ACE limit *for each 30-minute period*. One BA ACE limit "exceedance" for 30 consecutive minutes is now a violation of the BAL-001-2 standard and is subject to NERC enforcement and penalty.

[5] NERC defines Area Control Error ("ACE") as follows: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection. *See* Glossary of Terms Used in NERC Reliability Standards, p.2 of List of Terms, accessible at http://www.nerc.com/files/glossary_of_terms.pdf ("NERC Glossary of Terms").

Figure 2 shows a recent March 15, 2017 load stack, including the actual solar energy injections into the DEP BA. It shows the challenging ramping requirements that DEP is currently experiencing due to current QF penetration levels.

Figure 2



For this March 15th day, and similarly for any fall, winter, and spring load shape days, the BA experiences rapid up-ramp requirements in the late afternoon, early evening period ("late day period") due to customer load demand. However, that is when the solar QF energy injections into the BA are rapidly declining. In the late day period, the BA's load-following resources are operating at low output levels to accommodate QF energy injections; and therefore, the BA must meet increasingly steeper "net" ramping requirements to: (i) satisfy higher customer demands; and (ii) back-stand the deficit due to rapidly declining QF energy injections.

Due to this significant increase in "net" ramping demand for the late day period peak, DEP experienced two (2) BAAL Exceedance Alarms on March 15, 2017. DEP was able to respond and avoid having these "exceedances" become violations of the BAL-001-2 standard; however, increasing levels of solar QFs on the DEP system will increase risks of future NERC non-compliance.

Q. AS FURTHER BACKGROUND TO ADDRESSING PUBLIC STAFF WITNESS METZ'S REQUEST THAT THE COMPANIES PROVIDE ADDITIONAL DETAIL REGARDING THE NEW BAL-002-2 STANDARD AND ITS EFFECT ON SYSTEM OPERATIONS, WHAT ARE YOUR PROJECTIONS OF "NET" RAMPING DEMANDS ON THE DEP BA AT 2,200 MWS OF QF PENETRATION LEVELS?

A. At 2,200 MWs of QF penetration on the DEP BA, DEP will experience very steep "net" up-ramping and down-ramping demands. Figure 3 below shows a *near tripling* of the "net" down-ramping demand on the DEP BA at 2,200 MWs of QF penetration, from 400 MW/hour to 1,100 MW/hour. This is due to non-conforming increases in QF energy injections into the system, just as the system's customer load demand begins to drop. For fall, winter, and spring loads, following the morning peak, BA operators must ramp down DEP's load-following generation resources to match declining customer load demands. To now accommodate the QF energy increases after the morning peak, the BA operators must even more steeply accelerate the reduction of power output from the system's load-following resources.

<u>Figure 3</u>

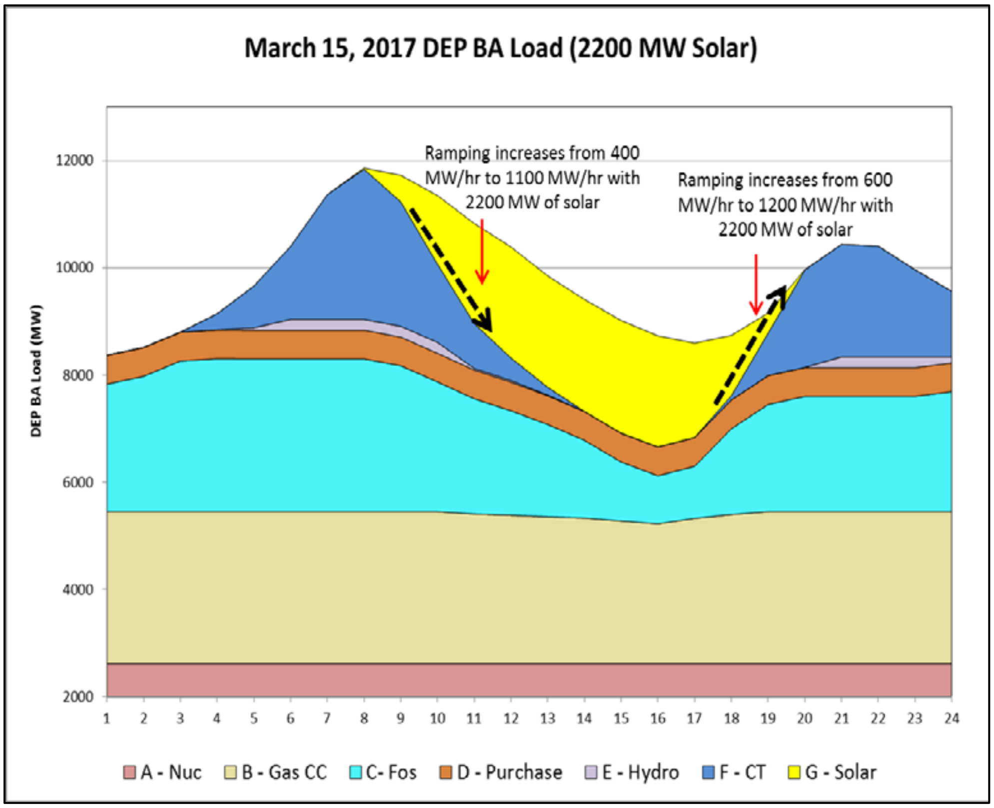


Figure 3 also shows the net up-ramping demand during that late day hours will *double* from 600 MW/hour to 1,200 MW/hour due to the rapid, non-conforming QF energy withdrawals, just when customer load demand increases for the evening peak. A 1,200 MW/hour up-ramping rate severely diminishes the BA's operational flexibility and imposes a higher risk operational environment. A generator failure or other disturbance, such as loss of transmission, would cause deficit energy on the BA that would result in NERC violations and serious challenges to providing reliable service.

Q. WITH THAT BACKGROUND, PLEASE DISCUSS THE IMPACTS OF THE NEW BAL-002-2 STANDARD THAT WILL BECOME EFFECTIVE ON JANUARY 1, 2018.

A. The currently effective version of the BAL-002 standard, BAL-002-1, considers only the "Loss of Generation" to invoke the deployment of contingency reserves, so that the BA experiencing the generator loss must recover to zero ACE or the pre-disturbance ACE within 15 minutes from the Loss of Generation event. Hence, the (i) loss of a DEP system generation asset; or (ii) a sharp reduction of QF energy injections in the BA due to the variability or intermittency of solar QF generation; or (iii) both occurring contemporaneously will increase the risk of non-compliance with the BAL-002-1 standard. As I discussed above in regard to the very steep late day ramping period, if DEP experienced a loss of generator disturbance event, or if during up-ramping the solar QF generation has a sharp decline due to sudden cloud cover, then there is increased risk that the DEP BA could violate the BAL-002-1 standard. It would also violate the BAL-002-2 standard.

The updated BAL-002-2, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event standard, effective January 1, 2018, will replace the "Loss of Generation" contingency with a more robust "Balancing Contingency Event" covering a broad range of credible events, against which the BA operator must recover the resource-demand balance *within 15 minutes* of the contingency event. Balancing Contingency Events include transmission element contingencies – *such as the loss of any of the non-firm, curtailable transmission between the DEP BA and DEC BA*. The BAL-002-2 standard's purpose is:

> "To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event."[6]

NERC's Glossary of Terms used in NERC Reliability Standards defines a "Balancing Contingency Event" as:

> "Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: a. Due to i. unit tripping, or ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE."[7]

In summary, the BAL-002-2 standard requires single contingency operations, planning, and response to broader and additional credible

[6] See BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, available at: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-002-2&title=Disturbance%20Control%20Standard%20%E2%80%93%20Contingency%20Reserve%20for%20Recovery%20from%20a%20Balancing%20Contingency%20Event&jurisdiction=United%20States

[7] *See* NERC Glossary of Terms, *supra* note 5.

contingencies that can create unexpected deviations in a BA's ACE, and requires restoration of the resource-demand balance within 15-minutes.

Q. HOW WILL THE CONTINUED ADDITION OF QFs IN THE DEP BA ADVERSELY IMPACT DEP'S AND DEC'S DAY-TO-DAY OPERATIONS AND CAPABILITY TO COMPLY WITH BAL-002-2?

A. As DEP experiences the connection of additional solar QFs on the BA, it will have to purchase increasing amounts of unconstrained and unscheduled PURPA energy – in excess of its operational ability to use the energy. DEP must then curtail that excess (or dump that excess into another BA). NCSEA Witness Johnson suggests that DEP ought to simply move the excess energy to DEC and deliberately rely on another BA's assets, such as DEC's pumped storage, to manage DEP's operational commitments.[8] He makes this suggestion even though the DEP and DEC BA's are only connected by hourly, as-available non-firm, curtailable transmission paths. Hence, the more mandatory long-term contractual commitments for operationally excess energy that DEP has, the more it must curtail to keep the BA in balance on a stand-alone basis.

Assume for example that DEP is exporting 1,000 MWs to a neighboring BA to try to manage its operationally excess energy, over hourly, as-available, non-firm, curtailable transmission, and that transmission is curtailed or a transmission facility contingency occurs resulting in immediate curtailment of the non-firm transaction. The loss of transmission action will

[8] NCSEA Johnson Testimony, at 214.

create sudden resource-demand imbalances on *two BAs* that will require each BA to restore its resource-demand balance in a quick manner to avoid BAL Standard violations, as discussed above. Explained another way, if DEP were exporting the 1,000 MWs of operationally excess energy to the DEC BA over hourly, as-available, non-firm transmission, and a transmission contingency resulted in the immediate curtailment of the 1,000 MW DEC import of DEP's excess energy, at that moment, DEC would experience a 1,000 MW deficit, and DEP would have an excess of 1,000 MWs. It is important to note that operationally excess energy on DEP exists after DEP has reduced its units' output to the LROL, and therefore, DEP has no ability to reliably reduce output from its synchronous load-following resources. Therefore, due to the challenge of curtailing 1,000 MWs of QF energy in a quick manner (i.e. 15-minutes), DEP's system reliability will be increasingly challenged along with DEP's and DEC's compliance with NERC's requirements. Any ability to dump operationally excess energy to DEC or any other neighboring BA will, therefore, be limited by the more robust BAL-002-2 standard.

Q. PLEASE CLARIFY WHAT YOU MEAN BY "NON-FIRM" TRANSMISSION.

A. "Non-Firm Transmission" is defined as: "Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption."[9] Non-firm transmission is subject to availability on an hourly basis, dependent on whether the holder of the firm transmission is using its

[9] *See* NERC Glossary of Terms, *supra* note 5.

transmission capacity or other transmission customers have made transaction reservations. Non-firm transmission is effectively the "leftovers" of the scheduling process, where firm transmission that is not scheduled day-ahead is released for hourly non-firm use. Availability of non-firm transmission will change as reservations made by wholesale customers and other transmission customers change over time. Furthermore, load-following designated network resource additions, both within DEP and in other BAs, are likely to reduce available transmission capability in the future.

Q. PUBLIC STAFF WITNESS METZ RECOMMENDS THE COMPANIES PROVIDE MORE DETAIL ON THE OPERATIONAL LIMITS OF THE "JOINT DISPATCH AGREEMENT" BETWEEN DEC AND DEP UNDER THE MODIFIED BAL-002-2 STANDARD. PLEASE RESPOND.

A. With respect to JDA transactions under the BAL-002-2 standard, it is important to consider the intended purpose of the JDA, which is to transfer incremental economic energy from the Companies' synchronous, fully-controlled generation from the system with lower marginal costs to displace higher cost system generation on the other system. The JDA is not a tool for managing balancing, regulating, or operating reserve requirements. Moreover, the JDA does not set up a joint balancing authority. Pursuant to 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, which approved the merger of Duke Energy and Progress Energy

Corporation (the "Merger"), DEP and DEC continue to operate as separate BAs and utilities, and each is responsible for its own independent resource planning and operations.[10] Put another way, the JDA is merely 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. Moreover, because firm transmission reservations support transactions where a party has an actual firm transmission need. Accordingly, under the Companies' FERC-approved Joint Open Access Transmission Tariff, in order to use firm transmission to support such non-qualifying JDA transactions between DEC and DEP (or for that matter for PURPA dump energy transactions), DEP would have to un-designate DEP's load-following network resources to secure firm transmission, which would have serious, adverse impacts on reliability.

Under the BAL-002-2 standard, the curtailment of non-firm transmission would trigger a contingency event against which each BA would have to recover within a 15-minute period. Assuming the JDA is used for its intended purpose, and each BA manages regulation, operating, and balancing

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[10] 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."

reserves independently, by curtailing excess energy when necessary, the JDA could plan to transfer economic energy from the Companies' fully-controlled synchronous generation to make hour-by-hour economic transfers. Under those conditions, each BA is more likely to recover from any curtailment of the non-firm energy transfers, because each BA would have the necessary responsive contingency resources to regulate energy up or down depending on the JDA energy flows from DEC to DEP or vice versa.

Q. PLEASE RESPOND TO PUBLIC STAFF WITNESS METZ'S RECOMMENDATION THAT THE COMPANIES FILE THEIR CURTAILMENT PROTOCOL WITH THE COMMISSION.

A. As noted by Public Staff Witness Metz, the Companies have provided to the Public Staff the current System Operations Reference Manual Carolinas, and 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. The Companies have not completed this guidance document at this time, but commit to share the document with the Public Staff as soon as it is completed and will agree to file such procedures after discussions with the Public Staff.

Q. NCSEA WITNESS JOHNSON DISMISSES THE COMPANIES' SYSTEM OPERATIONS CHALLENGES ASSOCIATED WITH OPERATIONALLY EXCESS ENERGY AS "GROWING PAINS" TO BE EXPERIENCED AS UTILITY-SCALE SOLAR BEGINS TO DISPLACE FOSSIL GENERATION. DO YOU AGREE?

A. No, I do not. System operators are charged with ensuring safety, reliability, security, and service to our customers. We are not allowed to replace operational discipline and integrity with acceptance of "growing pains," because hope and luck is not operational planning. We have to plan and then execute prudent operational discipline 24 x 7 x 365. In the current framework, the operational challenges will intensify as more than 2,200 MWs of solar facilities locate in the DEP BA. This growing level of PURPA solar interconnection is beyond growing pains.

Viewed another way, DEP will very soon have 2,200 MWs of solar facilities that will inject unconstrained, unscheduled, variable, and intermittent energy into the BA, in a manner that is non-conforming to load for most of the year. The adverse impacts to reliable system operations that I have described are challenging the system's capability to respond to abnormal system conditions, future load demand changes, and are causing risks to reliability and security conditions on the BA.

For the reasons I have extensively discussed in my direct and rebuttal testimony, and as recognized by Public Staff Witness Metz, the current and growing system operational challenges facing DEP and DEC are not merely "growing pains" to be accepted by the Companies as a temporary condition that will somehow resolve itself on their own. Instead, as set forth in the testimony of the Companies' other witnesses, it is appropriate to evolve the way in which solar QFs are added to and controlled on the Companies' energy grids to enable DEC and DEP to reliably serve our customers' energy needs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	)))))	REBUTTAL TESTIMONY OF GARY FREEMAN ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gary Freeman, and my business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the General Manager of Distributed Energy Resources Compliance & Origination for Duke Energy Corporation ("Duke Energy").

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I pre-filed direct testimony in this proceeding on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies") on February 21, 2017.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to address certain positions and arguments presented in the testimony of the North Carolina Utilities Commission – Public Staff ("Public Staff") Witnesses Jay B. Lucas and John R. Hinton; North Carolina Sustainable Energy Association ("NCSEA") Witness Carson Harkrader; and Southern Alliance for Clean Energy ("SACE") Witness Thomas Vitolo. Specifically, my rebuttal testimony rebuts the Public Staff's and NCSEA's alternative proposals for the North Carolina Utilities Commission ("Commission") to administratively establish a standard for a qualifying facility ("QF") to make a legally enforceable commitment to sell ("LEO"), as well as provides the Commission further detail regarding the

Companies' proposed contracting procedures as introduced in my pre-filed direct testimony. I also respond to SACE Witness Vitolo's speculative argument that reducing the Companies' standard offer eligibility to one megawatt ("MW") will unreasonably increase the number of projects proceeding through the Companies' interconnection queues.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. Freeman Rebuttal Exhibit 1 provides the Commission a revised streamlined Notice of Commitment Form ("NoC Form") for small QFs 1 MW or less eligible for DEC's and DEP's standard Schedule PP avoided cost tariffs. Freeman Rebuttal Exhibit 2 provides the Commission the Companies' proposed Notice of Intent to Negotiate Power Purchase Agreement form and contracting procedures under which large QFs above 1 MW would negotiate a power purchase agreement ("PPA") with the Companies, as introduced in my pre-filed direct testimony.

Q. PLEASE BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY.

A. My testimony addresses the Companies' recent experience since the Commission-approved NoC Form was adopted in 2015 that a QF project is establishing a LEO and purportedly making a legally enforceable commitment to sell at a time 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 even begun negotiations of a PPA with the utility. I emphasize the heightened importance of fixing North Carolina's

LEO policy in light of the Companies' proposal to reduce standard offer eligibility to 1 MW, and then introduce the Companies' modified proposal that larger QFs above 1 MW should make a legally enforceable commitment to sell by negotiating a PPA with the utility under Commission-approved contracting procedures.

Q. DOES PUBLIC STAFF WITNESS LUCAS APPROPRIATELY CHARACTERIZE THE COMPANIES' CONCERNS WITH THE CURRENT NoC FORM PROCESS FOR A QF TO ESTABLISH A LEGALLY ENFORCEABLE COMMITMENT TO SELL POWER?

A. Yes, he does. At pages 4-5 of his testimony, Witness Lucas recognizes the following key points presented in my direct testimony and in the testimony of Witness Kendal C. Bowman:

- **The LEO policy.** Under the Public Utility Regulatory Policies Act ("PURPA"), the purpose of a "QF's commitment through a LEO to sell its power to the utility should allow the utility to avoid other plans to construct new generation or purchase alternative power."
- **The current reality.** "In reality, the utility cannot avoid plans to construct future generation" based upon the current administratively-established LEO policy because "the current criteria do not commit the QF to build a generator at all."
- **Currently the "LEO risk" is assigned to customers.** "[C]ustomers bear the risk of providing a LEO to a QF that may not be able to meet its power delivery date" or may elect not to build the generator at all.

- **Customers are being obligated to pay "stale rates" when a LEO is established early in the interconnection process.** Where a QF has administratively established a LEO, "delays [in the interconnection process], as well as the time to construct a project, cause the actual power delivery date to lag as much as two to four years after the date of the establishment of the LEO. This late delivery of power forces Duke's customers to pay an avoided cost rate to the QF that may no longer be reflective of Duke's current avoided costs."

Q. DOES THE PUBLIC STAFF DISAGREE WITH THESE CONCERNS?

A. Not directly. The Public Staff does not specifically respond to the Companies' position that the purpose of a LEO under PURPA is to allow a QF to make a legally enforceable commitment to sell – 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.

However, the Public Staff does recognize that a QF cannot make a reasonable and informed commitment to sell its power prior to completing the System Impact Study. On page 9 of his testimony, Witness Lucas explains that "[u]pon 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." Also on page 9, Mr. Lucas recognizes that prior to moving through the interconnection 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."

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSAL TO EVOLVE THE CURRENT LEO POLICY BY ACTUALLY REQUIRING LARGE QFs TO MAKE A LEGALLY ENFORCEABLE COMMITMENT TO SELL?

A. No, they do not. While the Public Staff's proposal recognizes the need to evolve the LEO policy and current NoC Form in some respects by requiring a QF to become a Project A or Project B under Section 1.8 of the North Carolina Interconnection Procedures ("NCIP") and to at least ***begin*** System Impact Study, this does not make the QF's "commitment" through submittal of the NoC Form any more meaningful. The Public Staff does not seem to agree that a QF should actually be required to make a 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.

Q. HOW DOES NCSEA WITNESS HARKRADER DISCUSS THE QF'S COMMITMENT THAT SHOULD SATISFY THE LEO STANDARD?

A. At page 20, Witness Harkrader extensively discusses commitments made by a QF developer in the "early stages" of the QF development process including securing site control, obtaining regulatory approvals, and submitting an interconnection request. She concludes that "significant commitments – in terms of expenditure of time and financial resources and the securing of necessary approvals – are made toward the development of the QF before the interconnection study process is completed."

Q. ARE THESE COMMITMENTS IMPORTANT TO WHETHER A QF HAS MADE A LEGALLY ENFORCEABLE COMMITMENT TO SELL?

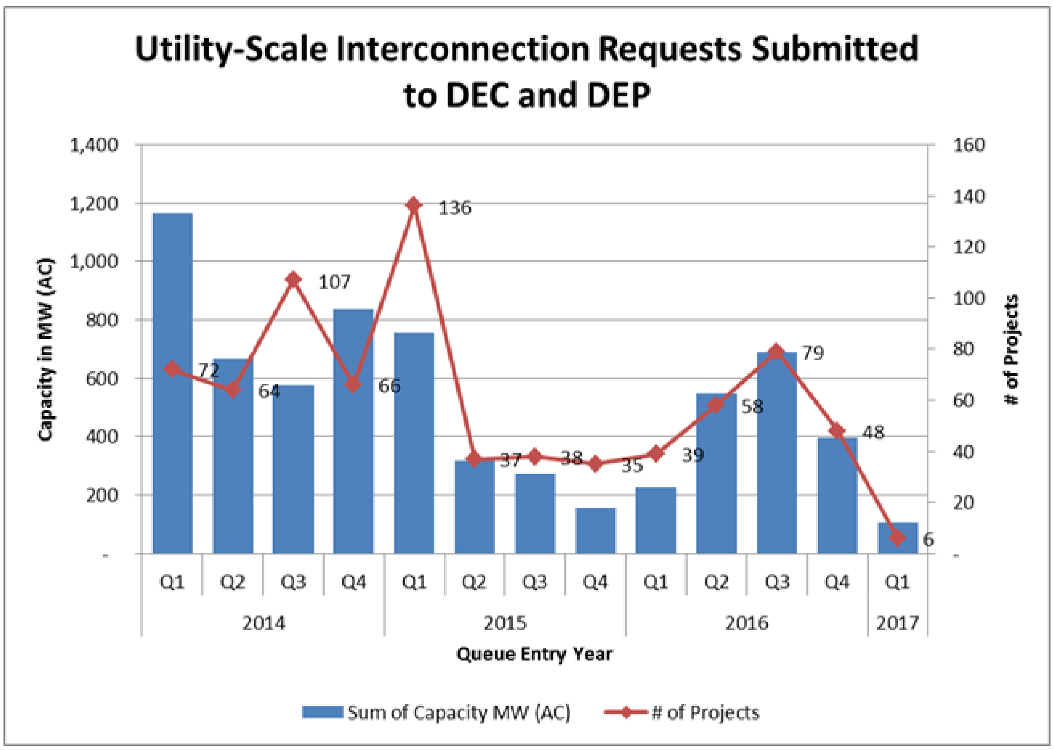
A. I don't dispute Ms. Harkrader's statements that early stage development of a QF includes making commitments of time and financial resources. However, these are not the commitments contemplated by the Federal Energy Regulatory Commission's ("FERC") regulations that provide that a QF can obligate the utility and its customers to purchase its power. A legally enforceable commitment to sell power requires a QF to commit itself to "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term." 18 C.F.R. 292.304(d). Only where a QF commits itself to deliver power over a specified term should a LEO arise.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S AND NCSEA'S PROPOSAL TO ADMINISTRATIVELY GRANT A QF A LEO 105 DAYS AFTER SUBMITTING A COMPLETE INTERCONNECTION REQUEST.

A. I disagree with this proposal because it does not require the QF to make a meaningful commitment to sell and would allow a QF to submit a "notice of commitment," thereby obligating the utility and customers, prior to receipt of interconnection study information that is needed to determine whether it is technically or economically feasible to interconnect at the QF's proposed point of interconnection. This essentially continues the current policy of providing a QF the right or option to sell at avoided cost, but creates no obligation that the QF will deliver power to the Companies.

Also, I do not read the 105-day requirement as being applicable to "On Hold" projects that will not begin study under NCIP Section 1.8 until the QF interconnection customer becomes a Project A or Project B. I addressed this interdependency concept extensively in my direct testimony, but would reiterate for the Commission that there are currently over 150 "On Hold" interconnection requests (not Project As or Bs) in DEC's and DEP's North Carolina interconnection queues and 33 different substations where far 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. This means that many new QF interconnection customers will be interdependent and not eligible to begin a System Impact Study 105 days after their interconnection request is deemed complete.

I would also like to respond to the implicit suggestion underlying this proposal that the delays in the interconnection study process have been within the utility's control. DEC and DEP have worked in good faith with the solar community, other QF developers, and our retail customers interested in installing distributed energy resources to study all interconnection requests in a non-discriminatory manner and have made reasonable efforts to meet the timeframes in the NCIP. However, as highlighted in the chart below, approximately 785 new utility-scale interconnection requests above 1 MW have been submitted since January 1, 2014 to interconnect more than 6,700 MWs of new generation to the Companies' systems. Of these projects, 28% have either withdrawn from the interconnection process or canceled their project. This suggests the speculative nature of establishing a LEO proximate to submitting the interconnection request, which occurs early in the QF development process.



To my knowledge, the level of utility-scale solar development on the DEP distribution system specifically is unprecedented across the country. I do not dispute that the interconnection study process is – as it should be – ultimately within the Companies' control in order 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. However, in my view, the primary cause of the Companies not meeting the NCIP's study timelines is not a dereliction of responsibility, but is primarily attributable to the continuing surge in new interconnection requests and the growing complexity of the distribution study process as multiple utility-scale generators propose to interconnect on the same circuit. As highlighted in the Companies' Joint Initial Statement, I look forward to continuing to work with other stakeholders to improve the North Carolina interconnection process when the E-100, Sub 101 stakeholder process recommences in May of this year.

Q. BOTH PUBLIC STAFF WITNESS LUCAS AND NCSEA WITNESS HARKRADER ALSO POINT TO FERC's RECENT *FLS ENERGY* ("FLS") ORDER AS SUPPORTING THEIR POSITION. DO YOU AGREE?

A. No, I do not. I extensively addressed this recent FERC decision in my direct testimony and will not do so again here. However, I would like to emphasize one key fact from that case for the Commission's consideration. In Paragraph 4, FERC highlights that all 14 FLS QFs had reached an agreement with the utility on all material terms of the PPA to sell their power and had tendered signed PPAs back to the utility on the date FLS asserted they had made a legally enforceable commitment to sell.[1] This is completely consistent

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

with the Companies' position and proposed contracting procedures, as discussed below. Where a QF negotiates and executes a PPA to sell its power to the utility, it seems completely reasonable that a subsequent administrative delay by the utility in delivering an interconnection agreement should not preclude a legally enforceable commitment to sell under the PPA from being established.

Q. PLEASE SUMMARIZE THE COMPANIES' CONCERNS WITH THE PUBLIC STAFF'S AND NCSEA'S LEO POLICY PROPOSAL FOR LARGER QFs.

A. The Companies' core disagreement with Public Staff's and NCSEA's proposals is that QFs should not continue to be allowed to establish a LEO without actually making a binding commitment to sell. Getting this policy right is very important, as the Companies are proposing to transition utility-scale QFs between 1 MW and 5 MWs to non-standard negotiated avoided cost rates, which are updated monthly versus only every two years under the standard tariff. It is also now significantly more important to ensure that larger QFs make a meaningful and binding commitment to sell through negotiation of a PPA, as the current NoC Form process allows QFs up to 80 MWs in size (a $150+ million dollar capital investment) to establish a LEO without making any actual commitment to sell power. For these reasons, the Companies have recommended developing contracting procedures for larger QFs where the QF can make a binding commitment to sell power over a specified term by signing a PPA.

Q. BEFORE ADDRESSING THE COMPANIES' PROPOSAL TO ADOPT CONTRACTING PROCEDURES FOR LARGE QFs, CAN YOU PLEASE BRIEFLY ADDRESS THE COMPANIES' LEO PROPOSAL FOR STANDARD OFFER QFs 1 MW AND UNDER?

A. The Companies have proposed continuing to use a streamlined NoC Form for small standard offer QFs less than 1 MW as an administratively-efficient approach to allowing these small QFs to become eligible for DEC's and DEP's standard Schedule PP avoided cost tariffs. As noted above, this approach is reasonable and appropriate for these smaller QFs because the Schedule PP rates, terms, and conditions are fixed for a two-year period. The Companies have proposed to modify the NoC Form for these small QFs to 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 and subject to the requirements specified in the tariff, including current time limits to begin delivery of power from the facility within 30 months of Commission approval of the standard offer avoided cost rates.

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSAL FOR A STREAMLINED NoC FORM FOR SMALL QFs?

A. Yes. Witness Lucas supports the Companies' proposal on page 7 of his testimony.

Q. HAVE THE COMPANIES DEVELOPED A STREAMLINED NoC FORM FOR SMALL QFs?

A. Yes. Freeman Rebuttal Exhibit 1 revises the existing NoC Form for small QFs to reflect the three requirements identified above.

Q. DOES THE PUBLIC STAFF ALSO SUPPORT THE COMPANIES' PROPOSAL TO ADOPT CONTRACTING PROCEDURES FOR LARGE QFs?

A. Yes. In his testimony, Public Staff Witness Hinton agreed with the Companies' proposal to develop contracting procedures that improve the efficiency of the negotiated PPA process and specifically recommended the Companies provide additional information regarding this proposal.

Q. HAVE THE COMPANIES DEVELOPED PROPOSED LARGE QF CONTRACTING PROCEDURES FOR THE COMMISSION'S REVIEW?

A. Yes. Freeman Rebuttal Exhibit 2 revises the existing NoC Form as a "notice of intent to negotiate a PPA" form. Section four of this form presents procedures for negotiating a PPA. The Companies recommend that the Commission direct the Companies to take input from the Public Staff, DNCP, and other interested parties and to submit any refinements to the proposed contracting procedures as a post-hearing filing.

Q. DO YOU HAVE ANY SPECIFIC COMMENTS REGARDING THE COMPANIES' CONTRACTING PROCEDURES FOR LARGE QFs?

A. Yes. The Companies' 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. Further, these 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, as contemplated by the LEO standard. 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.

It is also significant that the contracting procedures ensure that customers will not be obligated to purchase from a QF until the QF makes a commitment to sell by entering into a PPA. Prior to the QF making such a commitment, 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. While not expressly addressed in the contracting procedures, the Companies' PPA would also 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. After this 60-day due diligence period, customers should be protected from the risk of the QF's potential non-performance by including commercially reasonable liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform).

Q. DO THE COMPANIES HAVE A POSITION ON THE PUBLIC STAFF'S PROPOSAL THAT A QF THAT WITHDRAWS ITS NoC FORM BE PROHIBITED FROM ESTABLISHING A NEW LEO FOR TWO YEARS FROM THE DATE OF WITHDRAWAL AND BE LIMITED TO ESTABLISHING "AS AVAILABLE" ENERGY RATES DURING THAT TIME?

A. On page 14, Witness Lucas explains the Public Staff's concern that should avoided cost rates begin to increase,

> [A] QF may 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 customer expense.

The Companies recognize and agree with the Public Staff's concerns underlying this recommendation, and recommend this proposal be approved for small standard offer QFs subject to the Companies' proposed streamlined NoC Form. I would also highlight that requiring a large QF to execute a PPA and actually commit to deliver power is complementary to the Public Staff's proposal, as the PPA can include similar language if the QF fails to meet its obligations and terminates the PPA prior to commencing delivery of power.

Q. PLEASE ALSO RESPOND TO SACE WITNESS VITOLO'S ASSERTION THAT REDUCING THE STANDARD OFFER ELIGIBILITY TO 1 MW WILL RESULT IN A SIGNIFICANT INCREASE IN THE NUMBER OF INTERCONNECTION STUDIES THE UTILITY MUST PERFORM.

A. Witness Vitolo asserts at page 10 that "[o]ne potential outcome of reducing QF eligibility for a standard offer contract from 5 MW generation capacity to 1 MW is a dramatic increase in the number of projects under development" and suggests that this would "induce a significant increase in the number of interconnection studies the utility must perform." First, the argument that reducing the 5 MW standard offer to 1 MW will result in five times the number of projects under development is speculative at best. Second, I emphasize for the Commission that small QF projects eligible for the proposed 1 MW standard offer are also more likely to be eligible for and pass the NCIP Section 3 Fast Track screens, which provides a significantly more streamlined interconnection study process. As recognized by Public Staff Witness Hinton on pages 43-44 of his testimony, the likelihood that QF projects 1 MW or less will pass the NCIP Section 3 Fast Track process represents a “practical reason[s] for supporting a reduction in size to one MW.”

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

Instructions to QF: The QF shall deliver, via certified mail, courier, hand delivery or email, its executed Notice of Commitment to:

Director – Power Contracts
400 South Tryon Street
Mail Code: ST 13A
Charlotte, North Carolina 28202
Attn.: Wholesale Renewable Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF may be required to provide to the Company pursuant to this Notice of Commitment shall be delivered to the same address by one of the foregoing delivery methods.

1. [___________________] ("Seller") hereby commits to sell to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") all of the electrical output of the Seller's qualifying facility (the "Facility").

2. The name, address, and contact information for Seller is:

Name: ___________________ Telephone: _______________________

Address: _________________ Email: _______________________

3. By execution and submittal of this commitment to sell the output of the Facility (the "Notice of Commitment"), Seller certifies as follows:

Eligibility for Schedule PP

Seller is a qualifying facility ("QF") with a maximum nameplate capacity of 1,000 kW and is eligible for the Company's Schedule PP.

Report of Proposed Construction (Rule R8-65)

Seller has filed a report of proposed construction for its ____ kW (net capacity ac) Facility with the North Carolina Utilities Commission ("NCUC") pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. _________.

Application to Interconnect Generator to Company's System

Seller is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and has either submitted the NCIP Attachment 6 Interconnection Request Application Form for Certified Inverter-Based Generating Facilities No Larger Than 20 kW or has submitted the NCIP Attachment 1 Interconnection Request Application Form requesting NCIP Section 3 Fast Track review and the Company has notified the Seller-Interconnection Customer that its Interconnection Request is complete.

4. By execution and submittal of this Notice of Commitment Seller acknowledges that the legally enforceable obligation date ("LEO Date") for the Facility will be established upon the Company's receipt of this Notice of Commitment Form, which shall be based upon: (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company; (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company; (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above; or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

5. The LEO Date will be used to determine Seller's eligibility for the rates, terms and conditions of the Company's currently effective Schedule PP.

6. This Notice of Commitment shall automatically terminate and be of no further force and effect upon: (i) execution of a PPA between Seller and Company or; (ii) if such Seller does not execute a PPA, thirty (30) days after Company's delivery of an "executable" PPA to the QF by the Company, that contains all information necessary for execution and which the Company has requested that the QF execute and return.

The undersigned is duly authorized to execute this Notice of Commitment for the Seller:

____
[Name]

____
[Title]

____
[Company]

____
[Date]

NOTICE OF INTENT TO NEGOTIATE POWER PURCHASE AGREEMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

Instructions to "Qualifying Facility" ("QF") Seller: The QF shall deliver, via certified mail, courier, hand delivery or email, its executed Notice to:

Director – Power Contracts
400 South Tryon Street
Mail Code: ST 13A
Charlotte, North Carolina 28202
Attn.: Wholesale Renewable Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice shall be delivered to the same address by one of the foregoing delivery methods.

1. [____________________] ("Seller") has obtained QF status as of **[Date]** in **[FERC Docket Number]** and intends to sell the output of its QF cogeneration or small power production facility located at ____________ (the "Facility") to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") pursuant to a power purchase agreement to be negotiated between Seller and the Company.

2. The name, address, and contact information for Seller is:

   Name: ______________________ Telephone: ____________________

   Address: ____________________ Email: ________________________

3. **Certifications to Commence Negotiations**. In order to proceed with negotiations, Seller certifies as follows:

   (Select the applicable certification below)

   Certificate of Public Convenience and Necessity

   i. ____ Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its ____ kW (net capacity AC) Facility pursuant to North Carolina General Statute § 62-110.1 and North Carolina Utilities Commission ("Commission") Rule R8-64, on [insert date] in Docket No. _____________.

ii. ____ Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its ____ kW (net capacity AC) Facility with the Commission pursuant to Commission Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. _________.

Application to Interconnect Generator to Company's System

If Seller is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"),

i. ____ Seller is eligible for interconnection under NCIP Section 3 ("Fast Track," as defined in NCIP Section 3.1), has submitted the NCIP Attachment 1 Interconnection Request Application Form requesting Fast Track review and the Company has accepted the Section 3 Interconnection Request as complete and provided the Interconnection Customer with queue number ______.

ii. ____ Seller has submitted the NCIP Attachment 1 Interconnection Request Application Form requesting to interconnect under the NCIP Section 4 Study Process, the Company has accepted the Section 4 Interconnection Request as complete and provided the Interconnection Customer with queue number ______, and Seller has executed and returned a System Impact Study Agreement to begin the Section 4 study process after being preliminarily determined a Project A or Project B by the Company under NCIP 1.8.

4. **Procedures for negotiating power purchase agreement**. The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and will adhere to the following procedures during the negotiation process:

a. To obtain an indicative pricing proposal to sell the output of the proposed QF to the Company, Seller must provide in writing to the Company (and may include with this Notice), general project information reasonably required for the development of indicative pricing, including, but not limited to:

i. Qualifying Facility owner name, organizational structure and chart, contact information, and identify any affiliated QFs delivering power to the Company;

ii. Generation technology and other related technology applicable to the Facility;

iii. Fuel type (s) and source (s);

iv. Plans to obtain, or actual fuel and transportation agreements, if applicable;

v. Maximum design capacity (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;

vi. Proposed site location and electrical interconnection point;

vii. Where QF is or will be interconnected to an electrical system other than the Company's, plans to obtain, or actual electricity transmission agreements with the interconnected system;

viii. Quantity, firmness, and timing of daily and monthly power deliveries (including planned maintenance schedule), including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;

ix. Ability, if any, of QF to respond to dispatch orders from the Company;

x. Anticipated commencement date for delivery of electric output;

xi. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;

xii. Interconnection agreement status; and

xiii. Proposed contracting term for the sale of electric output to the Company.

b. The Company shall not be obligated to provide an indicative pricing proposal until all information described in Paragraph 4.a. has been received in writing from the Seller. Where the Company determines that the Seller has not provided sufficient information as required by Section 4.a., the Company shall, within 10 business days, notify the Seller in writing of any deficiencies.

c. Within 30 days following receipt of all information required in Paragraph 4.a., the Company will provide the owner with an indicative pricing proposal, which may include other indicative contract terms and conditions tailored to the individual characteristics of the proposed QF project. Such proposal may be used by the owner to make determinations regarding project planning, financing, and feasibility. However, the indicative pricing proposal provided to the Seller pursuant to Section 4.c. will not be final or binding on either party. Prices and other terms and conditions will become final and binding on the parties under only two conditions:

i. The prices and other terms contained in a PPA shall become final and binding upon execution of a final, agreed-upon PPA by the QF which is then presented for counter-execution by the Company; or

ii. If the Company and the QF cannot agree to the terms of a PPA, the applicable prices that would apply at the time request for arbitration is filed by the QF with the Commission shall be final and binding upon approval of such prices by the Commission upon a final non-appealable determination by the Commission that:

(a) a "legally enforceable obligation" has arisen where the QF is ready, willing, and able to enter into a contract with the Company and, but for the conduct of the Company, there would be a contract;

or
(b) the Qualifying Facility can deliver its electrical output within 180 days of such determination.

d. If the Seller desires to proceed with contracting its QF with the Company after reviewing the indicative pricing proposal, it shall request in writing that the Company prepare a draft PPA to serve as the basis for negotiations between the parties. In connection with such request, the Seller shall provide the Company with any additional information about the QF that the Company reasonably determines necessary for the preparation of a draft PPA, which shall include:
   i. Updated information of the categories described in Section 4.a.;
   ii. Evidence of site control for the entire contracting term;
   iii. Anticipated timelines for completion of key QF milestones,
   iv. to include:
      1. Licenses, permits, and other necessary approvals;
      2. Funding;
      3. Qualifying Facility engineering and drawings;
      4. Significant equipment purchases;
      5. Construction agreement(s);
      6. Interconnection agreement(s); and
      7. Signing of third-party Transmission Agreements, where applicable; and
   v. Additional information as explained in the Company's indicative pricing proposal.

e. If the Company determines that the Seller has not provided sufficient information as required by Section 4.d., the Company shall, within 10 business days, notify the Seller in writing of any deficiency.

f. Following satisfactory receipt of all information required in Section 4.d., the Company shall, within 15 business days, provide the Seller with the Companies' then current standardized non-tariff PPA customized as appropriate for the proposed QF. The draft shall serve as the basis for subsequent negotiations between the parties and, unless clearly indicated, shall not be construed as a binding proposal by the Company.

g. Within 90 calendar days after its receipt of the draft PPA from the Company pursuant to Section 4.f., the Seller shall review the draft PPA and shall either: (a) notify the Company in writing that it accepts the terms and conditions of the draft PPA and is ready to execute an PPA with same or similar terms and conditions as the draft PPA; or (b) prepare an initial set of written comments and proposals based on the draft and provide them to the Company. The Company shall not be obligated to commence negotiations with a Seller or draft a final PPA unless or until the Company has timely received an initial set of written comments and proposals from the Seller, or notice from the Seller in writing that it has no such comments or proposals and is requesting the draft PPA be finalized for execution.

h. If the Seller requests to commence negotiations to modify the draft PPA, as provided for in 4.g above, Seller shall contact the Company in writing contemporaneous with or after delivering its initial set of written comments to schedule PPA negotiations at such times and places as are mutually agreeable between the parties. In the course of PPA negotiations, the Company agrees that it:
    i. Shall not unreasonably delay negotiations and shall respond in good faith to reasonable additions, deletions, or modifications to the Companies' draft current standardized non-tariff PPA that are proposed by the Seller in a non-discriminatory manner;
    ii. May request to visit the site of the proposed QF;
    iii. Shall update its indicative pricing at appropriate intervals of not less than 60 calendar days from the date Seller commences negotiations to accommodate any changes to the Company's avoided cost calculations, the proposed QF or proposed terms of the draft PPA if the QFs' reasonably-proposed in-service date to deliver power to the Company is more than 180 days into the future;
    iv. Shall include any revised contracting terms, standards, or requirements that have occurred since the initial draft PPA was provided;
    v. May request any additional information from the Seller necessary to finalize the terms of the PPA and to satisfy the Company's due diligence with respect to the QF.

i. When both parties are in full agreement as to all terms and conditions of the draft PPA, including the price paid for delivered energy, and the Seller provides evidence that any applicable Transmission Agreements have been executed and/or execution is imminent, the Company shall prepare and forward to the Seller, within 10 business days, a final, executable version of the PPA.

j. The Seller shall, within 30 business days, execute and return the final PPA to the Company for execution. The Company will, within 10 business days of its receipt of the PPA executed by Seller, execute such PPA and return a copy to Seller.

k. Failure of the Seller to meet any timelines set forth in this section relieves the Company of any obligation to proceed under this negotiating procedure until such time as the Seller resubmits its QF and the procedures begin anew. If the Seller does not execute the final PPA within 30 business days, such final PPA shall be deemed withdrawn and the Company shall have no further obligation to the Seller unless or until such time the Seller submits a new Notice of Intent to negotiate on behalf of the QF.

The undersigned: 1) certifies the accuracy of the information provide in Section 3 of this Notice; 2) affirms that he or she has read and understands the procedures that the Company and Seller will adhere to in negotiating a PPA; and (3) is duly authorized to execute this Notice on behalf of the Seller:

____
[Name]

____
[Title]

____
[Company]

____
[Date]