PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Friday, April 21, 2017

TIME: 9:30 a.m. - 12:43 p.m.

DOCKET NO: E-100, Sub 148

BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Don M. Bailey

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Lyons Gray

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost Rates

for Electric Utility Purchases from Qualifying

Facilities - 2016

VOLUME: 8

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T A B L E O F C O N T E N T S:

PANEL OF

JOHN R. HINTON, JAY B. LUCAS and DUSTIN R. METZ

E X H I B I T S

(COURT REPORTERS NOTE: An Order Rescinding Confidential Treatment of Exhibit, filed May 1, 2017, ordered that DEC/DEP McConnell Cross Examination Exhibit Number 4 no longer be treated as confidential and shall be included in the public record.)

P R O C E E D I N G S:

CHAIRMAN FINLEY: Let's have a seat and come to order, please. Mr. Culley, you have a topic you want to address with us?

MR. CULLEY: Yes. Good morning and thank you, Mr. Chairman. Thad Culley for Cypress Creek Renewables. We were able to, as it concerns Duke Cross Exhibit Number 4, we were able to and can now stipulate to the authenticity of that document and would stipulate it into the record as well, without further objection, as a confidential exhibit. I understand Duke may have something to say on the matter as well.

CHAIRMAN FINLEY: All right. What does Duke have to say about that?

MR. SOMERS: Thank you. Good morning, Mr. Chairman. We appreciate that Cypress Creek took the time to authenticate their document. As to the confidentiality, I think as the Chair noted when this matter first arose yesterday a document that's on the internet whether it's got marked confidential or not, it's clearly not confidential if somebody like a lawyer at Duke Energy can type in a Google search and find the document. It's clearly not confidential, it's public. We don't know how many millions of people have seen that document, how many may have circulated it or used that for whatever purposes. Notwithstanding the fact that we understand Cypress Creek claims it's confidential, we don't know who breached their apparent confidentiality agreement. Once the document is public and on the internet, I don't see how it can be treated as confidential by this Commission and that would be our argument.

CHAIRMAN FINLEY: Well, for the moment we've treated it as confidential and we took it provisionally, took the evidence in, took the record on the confidential basis provisionally based on hearing from Cypress Creek as to determine whether or not it was an authentic document. That's where it will stay for the moment and we will think about that and address it. My expert on these types of matters, Commissioner Brown-Bland, has some views on how these things ought to be treated and I will confer with her and we'll let you know how we ultimately resolve that issue.

MR. CULLEY: Thank you, Mr. Chairman. And if I may ask for the opportunity, if the decision is made that this would be made a public exhibit, that we have the opportunity to submit a motion with additional information if we're able to conclude an investigation as to the circumstances of this document and how it was disclosed, as that pertains to possible trade secret materials and whether we can satisfy those standards. So I would just ask that we have an opportunity before it is included into the permanent public record and put onto a government website.

CHAIRMAN FINLEY: I want to tell you what we're going to -- when we end this case this morning (Laughter from the audience) we will establish a schedule for post-hearing filings and you can tell us whatever you think we need to know about all of that with those post-hearing filings.

MR. CULLEY: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: Anything else before we get started?

PANEL OF JOHN R. HINTON,
JAY B. LUCAS,
and DUSTIN R. METZ; were duly sworn and testified as follows:

MR. DODGE: Thank you, Chairman Finley. To get started I'll start with Mr. Hinton this morning.

DIRECT EXAMINATION

BY MR. DODGE:

Q Mr. Hinton, could you please state your name and address for the record?

A (MR. HINTON) John R. Hinton, 430 North Salisbury Street, Raleigh, North Carolina.

Q By whom are you employed and in what capacity?

A I work for the Public Service, I mean, Public Staff and I'm employed as the Director of Economic Research Division.

Q Did you cause to be filed on March 28, 2017, in this docket confidential testimony consisting of 65 pages?

A Yes.

Q Did you also cause to be filed on April 17th in this docket revisions to three pages in that testimony?

A Yes, I did.

Q Can you share those corrections with us, please?

A Yes. On page 19, the number 2012 should read 2022. The next correction is on Table 7 on page 29 of my testimony. We've provided a substitute table and I would submit that as opposed to reading out the correct numbers. The numbers are wrong concerning the Five-year and the Ten-year rates but the percentage changes were correct in that table. The third correction is on the last page of my testimony, page 65. The numbers for the 2014 DEC Approved Rates with regard to Capacity, Energy and Total Revenues were incorrectly written, or calculated. I've also submitted correction numbers for these three data, point values. In addition, in the fourth column, the % Change from 2014 read -29% for DEC's proposed rates. This is in regard to the change in the proposed rates versus the basis of what was approved in 2014. The correct number should be -36%. The next row in that Table 8 concerns the Public Staff's recommended Capacity, Energy and Total Revenues for a 5-megawatt solar plant, the incorrect number reads a -18%, the correct number should be -27%. Those are the corrections I'd like to submit.

Q Those corrections were filed on April 17th, the corrected pages for those three pages you just mentioned, correct?

A Correct.

Q Do you have any other changes or corrections to your direct testimony at this time?

A Yes. I would like on page 64 to add a minor clarification. The last words there of my verbal testimony is "rates by the Public Staff" and I'd include the words, a comma "not including the adjustments to Duke's natural gas price forecast" period or colon.

Q Could you repeat that sentence one more time? I'm sorry.

A On line 23 the added words are "not including the adjustments to Duke's natural gas price forecast".

MR. DODGE: Thank you. If -- excuse me, Chairman Finley, at this time I move that Mr. Hinton's direct testimony, as corrected, be entered into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Hinton's direct prefiled testimony filed on March 28, 2017, consisting of 65 pages, as corrected on April 17 and this morning, is copied into the record as though given orally from the stand, and to the extent to which it is marked confidential in the filing it shall be so marked in the transcript.

MR. DODGE: Thank you, Chairman Finley, and

I would note that pages 34, 35 and 56 of Mr. Hinton's testimony contains confidential information.

(WHEREUPON, the prefiled direct testimony of **JOHN ROBERT HINTON** is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of	)	TESTIMONY OF
Biennial Determination of Avoided Cost	)	JOHN R. HINTON
Rates for Electric Utility Purchases	)	PUBLIC STAFF – NORTH
from Qualifying Facilities – 2016	)	CAROLINA UTILITIES
	)	COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

Testimony of John R. Hinton
on Behalf of the Public Staff
North Carolina Utilities Commission

March 28, 2017

Q. PLEASE STATE FOR THE RECORD YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is John R. Hinton. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Economic Research Division of the Public Staff - North Carolina Utilities Commission. My qualifications are included in Appendix A to this testimony.

Q. WHAT ARE YOUR DUTIES AT THE PUBLIC STAFF?

A. My duties with the Public Staff are to conduct financial studies on the investor-required rate of return for water, natural gas, and electric utilities. I also review issues involving nuclear decommissioning plans, weather normalization of energy sales, electric utility meter sampling plans. the electric utilities' long-range peak demand and energy forecasts, and the integration aspect of the electric utilities' integrated resource plans (IRPs). I also review electric utilities' avoided cost biennial filings, as well as avoided cost issues for fuel cases and annual rider proceedings involving renewable energy and demand-side management and energy efficiency (DSM/EE).

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

A. The purpose of my testimony is to provide the Commission with the results of my investigation and analysis of the proposed avoided cost rates submitted by Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Virginia Electric & Power Company, d/b/a Dominion North Carolina Power (DNCP), (collectively, the utilities).

Q. PLEASE LIST THE ISSUES YOU ADDRESS IN YOUR TESTIMONY.

A. My testimony addresses the following issues: (1) a summary and analysis of the changes in avoided costs proposed by the utilities; (2) adjustments to avoided energy rates, including the proposal of DEC and DEP (collectively, Duke) to reset avoided energy rates every two years and the proposal of DNCP to adjust avoided energy rates based on the locational value of energy provided by qualifying facilities (QFs); (3) adjustments to avoided capacity calculations proposed by the utilities, including the proposal by Duke to eliminate a capacity credit in years when their IRPs indicate no capacity need, DNCP's proposal to eliminate a capacity credit based on the amount

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of existing QF generation in its North Carolina service territory, and the proposal by all three utilities to adjust the Performance Adjustment Factor (PAF); (4) proposed changes to the threshold for standard tariff eligibility; (5) proposed changes to the length of standard contracts; and (6) consideration of other ways to calculate avoided energy costs for solar photovoltaic (PV) systems.

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON PURPA AND THE ROLE OF THE COMMISSION IN SETTING AVOIDED COSTS RATES.

A. The Public Utility Regulatory Policy Act of 1978 (PURPA) and the rules adopted by the Federal Energy Regulatory Commission (FERC) to implement it require each electric utility to offer to purchase the electricity produced by QFs at the utility's "incremental cost of alternative energy," which is commonly referred to as the electric utility's "avoided costs." The incremental cost of alternative energy is defined as "the cost to the electric utility of the electric energy which, but for the purchase from the QF, such utility would generate or purchase from another source."[1] These rates must be just and reasonable to the electric consumers, in the public interest, and non-discriminatory to QFs.

[1] 18 C.F.R. § 292.101(b)(6).

Q. HOW ARE AVOIDED COSTS UTILIZED IN NORTH CAROLINA?

A. In addition to providing the basis for electric power purchases from QFs by a utility, the avoided costs determined by the Commission are utilized in other applications, including the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs; the determination of the incremental costs of compliance with the Renewable Energy Portfolio Standard (REPS) for cost recovery purposes; and in some ratemaking, such as determination of stand-by rates.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF SOME OF THE TRENDS IN QF DEVELOPMENT EXPERIENCED IN NORTH CAROLINA IN THE PAST TWO YEARS.

A. As discussed by Duke and DNCP witnesses, the number and capacity of QF facilities that have been constructed or are under development in North Carolina over the past five years has been tremendous, and a large percentage of those projects have been developed at or near the 5-megawatt (MW) standard threshold. Duke witness Bowman indicates that the amount of installed utility-scale solar capacity in DEC's and DEP's territories increased from approximately 125 MW in 2012 to over 1,600 MW in 2016. Further, there are an additional 4,900 MW of proposed solar projects that are either under construction or pending in DEC and DEP's interconnection queues. While it remains unknown whether and when each of these proposed facilities will be built, they potentially represent a significant increase in QF capacity in the coming months and years. As a matter of perspective, DEC and DEP's annual load growth forecasted in their IRPs over the next 15 years averages 286 MW and 172 MW, respectively.[2]

For DNCP, witness Gaskill testified that since February 2014, distributed solar in DNCP's North Carolina service territory increased from 58 MW under contract to over 435 MW currently operational at the distribution level, with an additional 537 MW under construction or pending in its distribution interconnection queue. In addition to the distribution level interconnections, witness Gaskill indicated that there are approximately 1.800 MW of active solar projects in the PJM interconnection queue for North Carolina at the transmission level. Together, these facilities represent almost 2,800 MW of solar projects that are operating or in the interconnection process, as compared with DNCP's average on-peak load of 518 MW in its North Carolina service territory. As such, these numbers indicate a tremendous amount of new solar QF generation in operation or underway.

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[2] See 2016 Integrated Resource Plans of DEC and DEP filed in Docket No. E-100, Sub 147 (September 1, 2016)

This significant growth of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers. In addition to exceeding load growth experienced by the utilities, the higher penetration of resources pose operational and technical challenges for the utilities in meeting their obligation to provide safe, reliable, and economic service to ratepayers.

Q. PLEASE EXPLAIN WHY THE PUBLIC STAFF BELIEVES THAT THE SIGNIFICANT INCREASE IN QF DEVELOPMENT INCREASES THE RISK OF OVERPAYMENT TO QFS BY RATEPAYERS.

A. In the preamble to its initial order implementing PURPA, FERC commented that "in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out."[3] While FERC found that this risk of overpayment and underpayment may generally even out over time, 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 is unparalleled. For DEP, in whose territory the greatest impacts of continued growth of solar have been seen, the risk of exposing

[3] *Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*. Order No 69, 45 Fed Reg at 12224.

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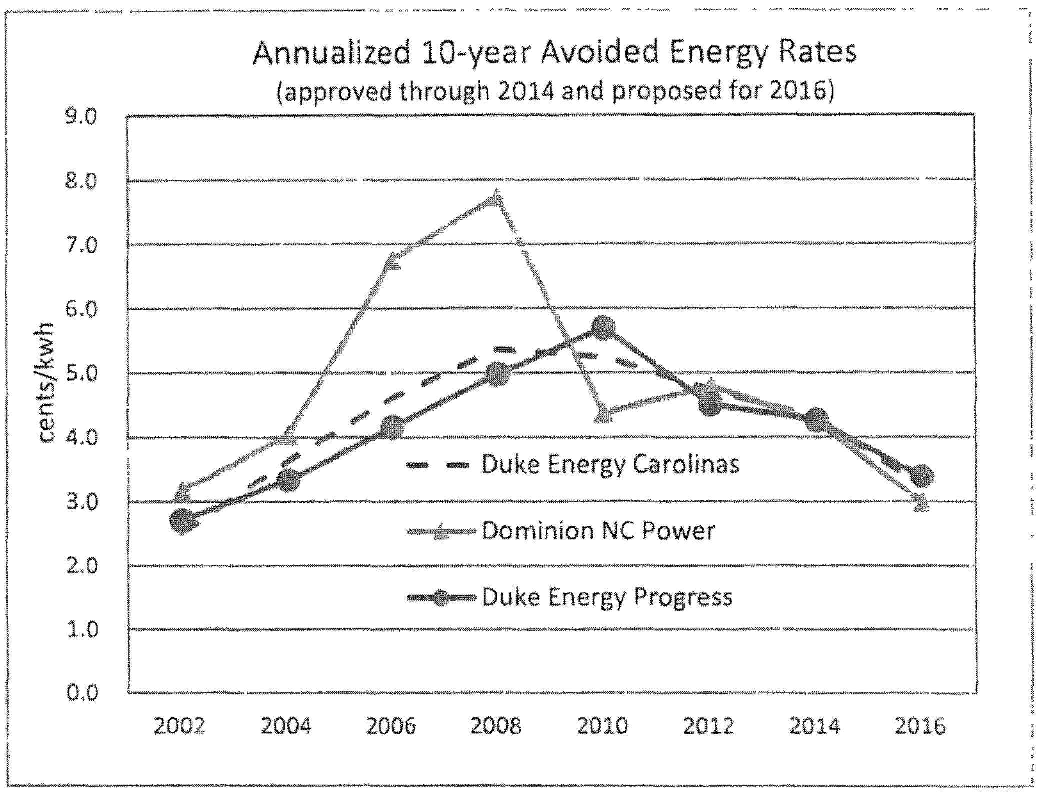
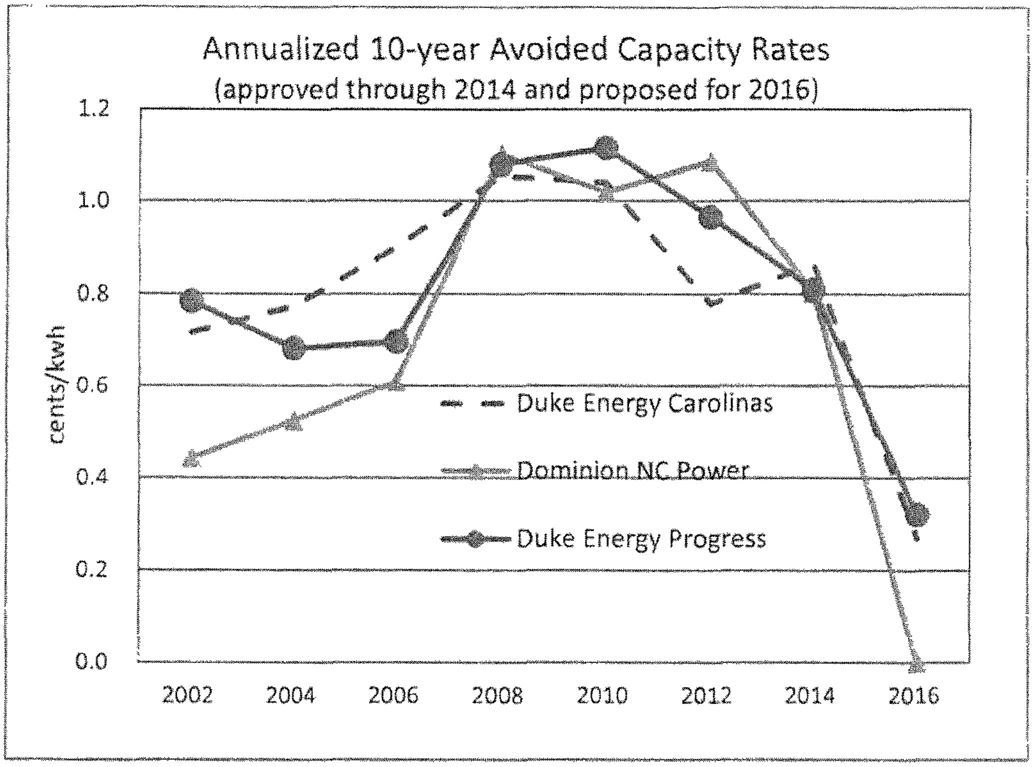
ratepayers to larger obligations to QFs, coupled with the added uncertainty associated with additional integration costs that are not yet fully quantified, may lead to higher utility rates.

Q. HOW DO THE PROPOSED AVOIDED COST RATES IN THIS PROCEEDING COMPARE TO PREVIOUSLY APPROVED RATES?

A. In general, the proposed rates are lower than previously approved rates, as the current cost of generation has fallen and projected cost of generation has decreased. The graphs below display the trends in approved and proposed avoided costs over the past 14 years.





PEAKER METHODOLOGY

Q. PLEASE DISCUSS THE METHODOLOGY HISTORICALLY APPROVED BY THE COMMISSION FOR ESTIMATING AVOIDED COSTS.

A. The Commission has long approved the use of the peaker methodology to establish avoided costs, most recently in its December 31, 2014 *Order Setting Avoided Cost Input Parameters* in Docket No. E-100, Sub 140 (Phase One Order) where the Commission found that use of the peaker method is reasonable and should be retained. In that Order, the Commission held that the "cost of the future baseload capacity in the utilities' capacity expansion plans is the appropriate measure for avoided cost purposes. The peaker method, as it was intended to be used, is a reasonable means of determining this cost and thereby for complying with Section 210 of PURPA." According to the theory of the peaker method developed by the National Economic Research Associates (NERA) in 1977,[4] if the utility's generating system is operating at the optimal point, the cost of a peaker (a combustion turbine, or CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Stated simply, the fuel savings of a baseload unit will offset its higher costs, producing a net cost equal to the capital costs of a peaker.

Q. DO YOU AGREE WITH THE USE OF THE PEAKER METHOD?

A. I generally agree with the use of the peaker method, and have testified in support of its use in multiple avoided cost proceedings before the Commission.[5] In reality, no utility system operates at the most optimal point. Utilities' planners have to deal with unexpected changes in load, cost of fuel, and other costs of generation that can

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[4] See Electric Utility Rate Design Study, topics 1.3 and 1.4 in "Gray" series of publications developed by NERA and jointly sponsored by the National Association of Regulatory Utility Commissioners, the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association (February 21, 1977).

[5] See Docket Nos. E-100, 106 (2006); E-100, Sub 136 (2012); and E-100, Sub 140 (2014).

challenge optimality. In addition, capacity has to be added in discrete increments; as such, utilities may have more or less than the optimal amount of capacity at any given point in time. This point was made in the EPCOR arbitration, Docket No. E-2, Sub 966, where Ms. Amparo Nieto, an economist with NERA, testified that this equality should be roughly achieved except in cases of severe deviation from optimality.[6]

Q. **DO YOU BELIEVE THAT THE LEVEL OF QF GENERATION HAS LED TO A SEVERE DEVIATION FROM OPTIMALITY?**

A. Not at this time. However, I am concerned that if a substantial number of the solar facilities in the interconnection queue noted by Ms. Bowman and Mr. Gaskill are built, then there is a growing likelihood of severe and persistent deviations from optimality. If estimates of future solar interconnections are correct, there may be years when reserve margins are significantly above the planned targets and it would be less likely that the capital cost of a peaker unit would equate to the net cost of a baseload unit (i.e. capital cost less fuel savings). The rapid increase in solar generation in DEP's service area has contributed to planned reserve margins over the next three years between 25% and 27%, as reported in DEP's 2016 IRP. Secondly, future substantial imbalances in capacity may

[6] Affidavit of Amparo Nieto, p. 5, filed August 6, 2010, in Docket No. E-2, Sub 966

continue to challenge the utilities' least cost planning. While there have been high reserve margins caused by lumpiness of generation additions or unexpected decreases in load, an additional 4,900 MWs from new QFs represents uncharted waters in DEC's and DEP's planning. Until recent years, this issue was quite manageable. As indicated by utility witnesses in this proceeding, however, these increasing amounts of intermittent QF generation continue to create challenges for day-to-day operations and long-term system planning.

Q. **IF GROWTH OF SOLAR QFS CONTINUES AT THE CURRENT RATE, WOULD THE PEAKER METHOD STILL BE APPROPRIATE?**

A. My concern is that the recent increases in solar generation and its expected growth raise doubt whether the traditional application of the peaker method would continue to be appropriate and provide the market with a correct price for capacity. An end result of the traditional application of the peaker method is that every kilowatt-hour (KWh) generated during on-peak hours provides capacity value and this value is quantified from the first day of QF operation, regardless of the utilities' needs for additional capacity. However, the practical reality of the addition of significant quantities of solar generation, especially in the DEP service area, challenges this assumption.

Q. PLEASE DESCRIBE THE PROPOSAL BY THE UTILITIES TO DELAY THE CAPACITY PAYMENT IN THE EARLY YEARS OF THE PLANNING PERIOD WHEN UTILITIES TYPICALLY DO NOT HAVE A CAPACITY NEED.

A. The utilities emphasize that FERC regulations do not require a utility to pay more to a QF than the utility's avoided costs. Specifically, Duke witness Snider maintains that the FERC has found that avoided costs should not include the cost for capacity unless the QF purchase will permit the purchasing utility to avoid building or purchasing capacity. DNCP witnesses Gaskill and Petrie maintain that DNCP's membership in PJM requires the utility to procure capacity for at least three years into the future, which results in DNCP having met all of its capacity needs at all times over those initial three years. Thus, all three utilities propose to include zeroes for their avoided capacity costs during the near-term years of the planning horizon. In addition, DNCP proposes to make no payment avoided capacity in the short-run and over the next ten years.

Q. DO YOU BELIEVE THAT CHANGES IN THE AMOUNT OF SOLAR GENERATION IN NORTH CAROLINA WARRANT A REVISION IN THE APPLICATION OF THE PEAKER METHOD?

A. Contrary to the Public Staff's position in prior proceedings regarding the use of zero capacity value in certain years, I believe that in light of current circumstances, it is appropriate for utilities to make a capacity payment to QFs only when additional capacity is needed on the system. I believe that the level of solar generation and the amount of solar generation in the interconnection queue warrant a departure from a traditional application of the peaker method. By 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.

Q. DOES THE PUBLIC STAFF SUPPORT DUKE'S PROPOSAL FOR THE PURPOSES OF THIS PROCEEDING?

A. Yes, the Public Staff supports Duke's proposal to limit capacity payments until the IRP dictates a capacity need in this proceeding. However, in future proceedings, conditions may lend to reconsideration of this issue, and continued applicability of the peaker method.

Q. WHEN DO DEC AND DEP INDICATE FUTURE CAPACITY NEEDS IN THEIR 2016 IRPS FILED IN DOCKET NO. E-100, SUB 147 (2016 IRP PROCEEDING)?

A. DEC indicates a resource need of approximately 3,903 MWs over the planning period (2017-2031), with the first resource need in the

2022/2023 timeframe,[7] and DEP indicates a resource need of approximately 4,071 MWs over the same planning period, with the first resource need in 2021/2022.[8]

AVOIDED CAPACITY RATES

Q. PLEASE DESCRIBE THE PROCESS USED TO CALCULATE AVOIDED CAPACITY COSTS.

A. Unlike the calculation of avoided energy costs, which entail hundreds of inputs, the calculation of avoided capacity costs incorporates considerably fewer inputs related largely to the installed cost of a CT. These inputs include each utility's financial carrying cost for the CT, a cost component for fixed operations and maintenance (O&M) costs, an adjustment for line losses and working capital, and a PAF.

The input with the most impact on the avoided capacity cost is the projected installed cost of the CT per kW. The second most influential assumption is the carrying cost rate for the CT. The carrying cost calculation can be rather complex; however, it generally involves the application of factors such as the cost of capital, property

[7] 2016 Integrated Resource Plan of DEC, Docket No. E-100, Sub 147, p. 39 (September 1, 2016).

[8] 2016 Integrated Resource Plan of DEP, Docket No. E-100, Sub 147, p. 40 (September 1, 2016).

and income tax rates, deferred taxes, insurance rates, and the projected inflation rate over the life of the CT. The carrying cost rate includes the cost of depreciation, which is dependent on the assumed useful life of the CT. The third most influential component is the costs of fixed O&M, which includes the costs of major maintenance events, inspections, and system overhauls. The remaining cost components relate to adjustments for avoided working capital and avoided line losses, and the application of the PAF.

Q. PLEASE DISCUSS YOUR REVIEW OF DEP'S and DEC'S PROPOSED AVOIDED CAPACITY RATES.

A. DEP made several revisions to its calculations of its avoided capacity rates for Schedule PP-3: All Other QFs. The first adjustment was to include zero values for capacity until its 2016 IRP shows a capacity need, as discussed above.[9] The impact of this adjustment is to reduce the 10-year present value of the future avoided capacity cost by 55%. The second adjustment was to reduce the PAF from 1.20 to 1.05, which lowered the annualized capacity cost by approximately 13%.[10] The third adjustment was to change the

[9] The use of zero values is displayed on DEP Exhibit 2, Pages 5 and 11 of 14
[10] The use of the lower PAF is shown is displayed on DEP Exhibit 2, Pages 6 and 12 of 14

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. The change revised the value of capacity from a seasonal weighting of 60% summer and 40% non-summer to 20% summer and 80% non-summer. The impact of these revisions reduced DEP's 10-year summer capacity rate by 87%, and the non-summer by 21%, and the annualized capacity rate by 60%. The following table provides a summary of the annualized changes for DEP.[11]

Table 1

DEP's Schedule PP-3: Non- Hydroelectric QFs – Option B			
Capacity Rates	Approved	Proposed	% Difference
10-Year Fixed			
Summer	6.27	0.83	-87%
Non-Summer	2.43	1.93	-21%
Annualized	0.81	0.32	-60%

Note: The proposed capacity rates are shown in DEP Exhibit 6, page 2 of 4.

DEC made the three same adjustments, reducing its 10-year summer capacity rate by 90%, the non-summer capacity rate by 38%, and the annualized capacity rate by 69%. The following table provides a summary of the annualized changes for DEC.

[11] I note that the annualized rates used above assume QF generation over all of the hours of the summer and non-summer months across the 8,760 hours per year (i.e. more applicable to a landfill gas QF than a solar QF).

Table 2

DEC's Schedule PP: Non-Hydroelectric QFs – Option B			
Capacity Rates	Approved	Proposed	% Difference
10-Year Fixed			
Summer	6.68	0.69	-90%
Non-Summer	2.58	1.61	-38%
Annualized	0.84	0.27	-69%

Note The proposed capacity rates are shown in DEC Exhibit 6, page 2 of 4.

Q. **PLEASE DISCUSS YOUR REVIEW OF DNCP's PROPOSED AVOIDED CAPACITY RATES.**

A. DNCP maintains that the existing and projected level of solar generation exceeds the load such that there are no more capacity costs to be avoided with additional QF generation. DNCP contends that any new solar generation in its North Carolina service territory will not cause it to avoid any capacity; thus, it proposes no capacity rates.

Q. **DO YOU AGREE WITH DNCP'S POSITION THAT THERE IS NO AVOIDED CAPACITY VALUE ASSOCIATED WITH ANY INCREMENTAL QF GENERATION?**

A. No. DNCP's proposal to assign no capacity value to future QF generation because there is more generation in DNCP's North Carolina service territory than load seems to run counter to general principles of utility system planning. Utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis. This system perspective is applied in various regulatory proceedings. For example, one of the central arguments in DNCP's application to join PJM was that DNCP's membership would make the Company part of a vast integrated transmission system with interfaces with PJM-E, PJM-W, and AEP with greater access to generation resources, load diversity, and improved reserve sharing across the region.[12] DNCP's 2016 IRP indicates a capacity need of approximately 4,457 MWs, with the first resource need in 2022.[13] As such, I do not find the Company's argument that there is no capacity value associated with incremental QF generation as reasonable.

Q. DO YOU AGREE WITH THE PROPOSED INSTALLED COSTS OF A CT USED BY THE UTILITIES?

A. The CT costs and inputs used by the utilities appear to be reasonable and in compliance with the Commission's holding in the Phase One Order that utilities use the installed cost of a CT per kW from publicly available industry sources, such as the EIA, PJM's cost of new entry studies, or comparable data, tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.[14]

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[12] See testimony of DNCP witness Paul Koonce in Application of Dominion North Carolina Power to Join PJM as PJM South in Docket No. E-22, Sub 418, filed on May 3, 2004.

[13] 2016 Integrated Resource Plan of DNCP, Docket No. E-100, Sub 147, p. 5 and p. A-130 (April 29, 2016).

[14] Phase One Order at p. 48.

ADJUSTMENT TO PAF

Q. WOULD YOU PLEASE DESCRIBE THE PAF AND ITS HISTORY?

A. Yes. In the early years of the implementation of PURPA, the Commission approved a capacity credit adjustment based on the utilities' reserve margin of 20%. In those years, the Commission accepted the use of a 20% reserve margin adjustment to account for avoided reserves and to allow a QF to have reasonable opportunity to obtain its full avoided capacity payment.[15] In the 1990 biennial avoided cost proceeding, Docket No. E-100, Sub 59, the reserve margin adjustment was subsequently replaced with the PAF and has remained in effect since that time.[16] In support of the PAF, Public Staff witness Chamberlin testified that reserve margins are required for reliability; as such an increase of 1 MW of load required an increase in generation of 1.20. He maintained that QF generation does not change a utility's reserve margin adjustment; rather, it is an alternative source of supply. As such, the previously 20% reserve margin adjustment should be based on a 20% adjustment for actual performance.[17] The Commission has consistently recognized in its

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[15] The Public Staff notes that if the Commission were to utilize the reserve margin adjustment at this time, the adjustments would be 1.17 for DEC and DEP and 1.125 for DNCP.

[16] See, e.g., Docket No. E-100 Subs 66, 74, 79, 81, 87, 96, 100, 106, 117, 127, 136, and 140.

[17] Testimony of John H. Chamberlin filed on behalf of the Public Staff in Docket No. E-100, Sub 59 at p. 25 (February 8, 1991)

avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constituted the utility's avoided capacity costs.

More specifically, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate all on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled.[18] Using a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83% of the on-peak hours. The Commission has previously concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83% of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. Despite DEC's repeated challenges to the PAF, the Commission has consistently reaffirmed the use of a 1.20 PAF.

Q. **PLEASE DESCRIBE THE PROPOSAL BY DUKE TO ADJUST THE PAF.**

[18] See e.g., *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 127, pp. 11-12 (2011).

A. In this proceeding, Duke has proposed a PAF of 1.05, which is based on a CT with a 95% availability factor. Although the percentage and subsequent percentage has changed, this is basically the same argument that DEC has made in past proceedings.[19]

Q. DO YOU AGREE WITH THIS POSITION?

A. I disagree with Duke's argument that the consideration of whether there is an opportunity for QFs to earn their full capacity payment should be irrelevant as to whether utilities may recover the full costs of their generating units. My understanding is that PURPA discourages discrimination between the utility and a QF; as such, the QF deserves a reasonable opportunity to collect its full capacity payment. In my opinion, this concept should be tempered with consideration of the utilities' obligation to serve and a QF's obligation to honor the contractual provisions of the purchase power agreement (PPA).

In addition, with respect to the argument that the starting reliability of a CT should be used to establish the PAF, the Commission has specifically rejected the use of a CT for this purpose, most recently in the Sub 140 proceeding. In that proceeding, the Commission

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[19] DEC Initial Statements filed in Docket No. E-100, Subs 41A, 59, 66, 79, 87, and 96, in which DEC proposed a PAF of approximately 1.12 based on an availability factor of approximately 88%. In Docket No. E-100, Sub 100, DEC lowered its recommended PAF to 1.0832 based on a 92.32% availability factor; in Docket No. E-100, Sub 106, DEC recommended a 1.20 PAF, which it continued to recommend through the 2014 Proceeding.

concluded that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are just a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

Q. WHAT IS THE PUBLIC STAFF'S POSITION ON THE PAF?

A. The Public Staff agrees with the Commission's previous conclusions that if a QF's availability is similar to that of the utility's baseload fleet, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. As discussed in Public Staff witness Metz's testimony, the Public Staff evaluated the capacity and availability factors reported by the utilities in their monthly baseload power plant performance filings and other sources and calculated an average baseload availability over the past five years of 86.33%, which equates to a PAF of 1.16. As such, I recommend that the Commission adopt an updated PAF of 1.16 for avoided capacity calculations.

Q. HAVE YOU REVIEWED DEC'S AND DEP'S PROPOSAL TO ADJUST THEIR SEASONAL ALLOCATION FACTORS IN THEIR AVOIDED CAPACITY RATE CALCULATIONS?

A. Yes. DEC and DEP have proposed to adjust the seasonal allocation factors used to assign weightings for avoided capacity between seasonal months in calculating their avoided capacity rates. Their proposed changes are in the tables below:

Table 3: DEC's Seasonal Allocation Factors

	Option A		Option B	
	On Peak Months	Off Peak Months	Summer Months	Non-Summer Months
Sub 140	80%	20%	60%	40%
Sub 148	100%	0%	20%	80%

Table 4: DEP's Seasonal Allocation Factors

	Option A		Option B	
	Summer Months	Non-Summer Months	Summer Months	Non-Summer Months
Sub 140	60%	40%	60%	40%
Sub 148	20%	80%	20%	80%

Summer Months include June through September
Non-Summer Months include October through May
On Peak Months include December through March and June through September
Off-Peak Months include April, May, October, and November

Q. WHAT IS THE BASIS FOR THE PROPOSED CHANGES TO THE SEASONAL ALLOCATION FACTORS?

A. Witness Snider testifies that DEC and DEP used a loss of load risk as determined by their respective 2016 resource adequacy studies to support the shift in the seasonal allocation factors. In previous avoided cost proceedings, these factors have been based on seasonal CT operational data. In response to the Public Staff's data request, Duke stated that loss of load risk was the proper metric to represent system reliability. In previous avoided cost proceedings, CTs were used more as a reliability resource. However, recently the Duke's CT resources have been used more than just for reliability, due primarily to low natural gas prices. The data request response states that this change in usage diminishes the capacity value directly related to CT operations. As such, Duke states that the loss of load risk was a more direct indication of capacity benefits. The proposed percentages were derived from the 2016 resource adequacy studies.

Q. DOES THE PUBLIC STAFF HAVE CONCERNS WITH DUKE'S JUSTIFICATIONS FOR CHANGING THE SEASONAL ALLOCATION FACTORS?

A. Yes. The Public Staff continues to have concerns that the proposed seasonal factors may shift an excessive emphasis toward the winter periods than appropriate. It is true that in the 2014 and 2015 DEC and DEP have experienced significant winter peaks, and in 2014 struggled to satisfy the load conditions on their systems. However, the Public Staff does not believe that the significant shift of avoided capacity values to the winter periods should be made at this time. 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.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION WITH REGARD TO DEC'S AND DEP'S PROPOSED CHANGES TO SEASONAL ALLOCATION FACTORS?

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

Avoided Energy Rates

Q. PLEASE DISCUSS YOUR REVIEW OF DEP'S AND DEC'S PROPOSED AVOIDED ENERGY RATES.

A. I began my review by comparing the avoided energy rates proposed by each utility. DEC and DEP are proposing a structural change to their avoided energy rates in this proceeding in that they are no longer offering fixed 5-year, 10-year, and 15-year energy rates; rather they are proposing that the energy rates paid to QFs be recalculated every two years. As such, the only fixed energy rate that DEC and DEP propose is the variable or 2-year rate as more fully discussed later in my testimony.

The Companies' proposed elimination of the fixed 5-, 10-, and 15-year energy rates does not allow for a comparison with existing fixed energy rates; however, Tables 5 and 6 below provide comparisons of DEC's and DEP's proposed rates with the previously approved energy rates for hydroelectric QFs in Docket No. E-100, Sub 140 (2014 Proceeding).[20] As noted in their filing, DEC and DEP decided largely to keep the same structure in calculating their avoided energy costs for hydroelectric and all other QFs. The percentage changes, ranging between -5% and -24%, largely reflect decreases in the expected costs of generation over the next 15 years from the Sub 140 avoided energy rates.

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[20] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 140 (December 17, 2015).

Table 5

DEP's Schedule PP (NC):
Hydroelectric QFs with No Storage – Option B – Energy Rates

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	3.63	-7%	3.47	-13%	3.58	-24%	3.92	-24%
Non-summer	3.28	-5%	3.21	-10%	3.34	-20%	3.62	-20%
Annualized	3.35	-6%	3.27	-10%	3.39	-21%	3.68	-21%

Note: The proposed energy rates are shown in DEP Exhibit 6, page 4 of 4.

Table 6

DEC's Schedule PP (NC):
Hydroelectric QFs with No Storage – Option B – Energy Rates

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	3.59	-7%	3.74	-13%	4.06	-24%	4.59	-24%
Non-summer	3.16	-5%	3.27	-10%	3.42	-20%	3.66	-20%
Annualized	3.25	-6%	3.37	-10%	3.56	-21%	3.86	-21%

Note: The proposed energy rates are shown in DEC Exhibit 6, page 4 of 4.

Q. PLEASE DISCUSS YOUR REVIEW OF DNCP'S PROPOSED AVOIDED ENERGY RATES.

A. Unlike DEC and DEP, DNCP did not propose a 15-year avoided energy rate for the hydroelectric QFs. The table below compares the variable, 5-, and 10-year avoided energy rates to the rates approved in the 2014 Proceeding, and shows that the proposed energy rates are 14% and 30% lower than the avoided energy rates approved in the 2014 Proceeding.

Table 7

DNCP's Schedule FP Schedule 19 – Option B – Energy Rates								
	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	3.292	-14%	3.189	-28%	3.394	-29%	NA	NA
Off-peak	2.656	-18%	2.687	-28%	2.872	-30%	NA	NA
Annualized	2.791	-17%	2.793	-28%	2.983	-30%	NA	NA

Note: The proposed energy rates are shown in DNCP Exhibit 12, page 2 of 2.

Q. PLEASE DISCUSS THE METHODOLOGY USED BY THE UTILITIES TO ESTIMATE THEIR AVOIDED ENERGY COSTS.

A. All three utilities use either the PROMOD or the PROSYM production costing model to estimate their avoided energy costs over the next 10 to 15 years. The models provide a chronological estimate of the hourly fuel costs, variable O&M costs, and generation unit start-up costs associated with the production of energy. This estimate is performed by replicating the future costs of operating each utility's generating units combined with other supply-side resources, such as its DSM programs and purchases from other generators. The model dispatches the generating units in a least cost manner subject to various constraints, such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times. The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts and the resource expansion plan from its

IRP. Multiple iterations of the model are performed that simulate operating conditions associated with possible forced outages.

Each utility performs two model runs: one at full load and one that assumes 100 MW or 150 MW of zero cost power. The difference between the two runs represents the avoided energy costs associated with QF generation. The avoided energy costs are based upon the marginal cost of the last unit dispatched in the generation stack in each hour combined with adjustments for reductions in working capital and line losses.

Q. WHAT CAUSED THE DECREASE IN THE UTILITIES' AVOIDED ENERGY RATES?

A. The largest factor was the decrease in the forecasted natural gas and coal prices over the next 10 years. On average, DEC and DEP have reduced their predicted natural gas prices by approximately 14% and their predicted coal prices by approximately 13% from those in the 2014 Proceeding. DNCP's forecasted natural gas and coal prices declined by approximately 8% and approximately 23%, respectively, from its price forecasts in the 2014 Proceeding. The MWh output, heat rates, and other generating unit characteristics were comparable to those previously assumed. Fuel price forecasts are often the most influential factor on avoided energy costs and can cause significant changes between proceedings, largely because fuel costs for marginal units often have greater impact than variable O&M and generation start costs.

Q. ARE THE INPUTS USED IN THE CURRENT CALCULATIONS OF AVOIDED ENERGY COSTS REASONABLE?

A. I believe most of the inputs are reasonable; however, I have concerns with Duke's use of 10-year forward prices to develop its price forecast for natural gas.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE FUEL FORECASTS UTILIZED BY DUKE.

A. As in the 2014 Proceeding and the 2016 IRP Proceeding, I have concerns with DEP's and DEC's over-reliance on long-term forward prices for their fuel forecasts. In their 2014 IRPs, DEC and DEP incorporated five years or less of forward price data before transitioning their fuel forecast to a long-term fundamental natural gas price forecast. The Companies made changes to this approach in their 2015 IRP updates by extending the period on which they relied on forward price data to ten years. In the 2014 Proceeding, the Public Staff and other parties advocated that the DEC and DEP return to their previous use of forward prices for no more than five years of the forecast before transitioning to a fundamental forecast developed by energy economists and gas analysts that estimate the future demand and supply of natural gas. In its December 17, 2015, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in the 2014 Proceeding, the Commission ordered DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts constructed in a consistent manner with those utilized in their 2014 IRPs. In this proceeding, however, DEC and DEP are again proposing to use ten years of forward prices.

Q. DOES DNCP INCORPORATE FORWARD PRICE DATA IN DEVELOPING ITS LONG TERM FORECASTS?

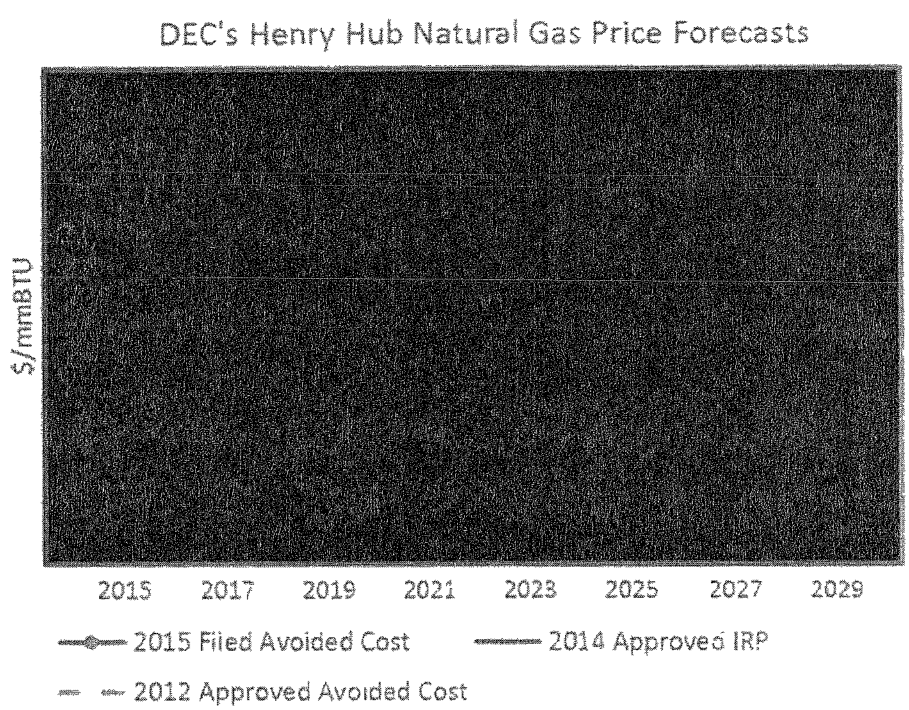
A. Yes. DNCP utilized forward price for the first 18 months and then blends the forward prices with a fundamental price forecast for the next 18 months to transition to its long-term forecast developed by ICF International, Inc. (ICF). DNCP employs a similar process of blending a short-term forward price forecast to transition to a long-term price forecast for coal. This blending allows for a smooth transition to the long-term fundamental forecast, as compared to Duke's abrupt transition.

The Public Staff supports the use of forward prices as a component in the development of a long-term price forecast. The use of five years is reasonable and appropriate because the market for these contracts are relatively liquid; whereas, 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. Fundamental price forecasts and forward price-based forecasts are different and have different applications. One such difference can be observed in the changes in forward prices, especially as futures traders respond to temporary conditions, as compared to fundamental price forecasts that are based on future demand and supply conditions that involve a more measured and tempered response to expected changes in the natural gas market.

Q. HAVE DEC AND DEP ALWAYS RELIED ON TEN YEARS OF FORWARD PRICE DATA?

A. No Prior to 2012, DEC incorporated two-year forward prices combined with a long-term fundamental natural gas price forecast in developing its IRP. More recently, in their 2013 and 2014 IRPs, DEC and DEP incorporated five years of future prices with their long-term forecasts. However, DEC and DEP used ten years of forward data to develop their 2014 avoided energy rates. An over-reliance on forward price data can call into question the reasonableness of the long-term forecasts. In addition, the Public Staff and other parties indicated in the Sub 140 Proceeding that they preferred DEC's approach prior to its merger with DEP of incorporating forward prices for the first few years of the forecast with a smooth transition to a fundamental forecast. Shown below is a graph from the Public Staff's Initial Statement in the 2014 Proceeding:

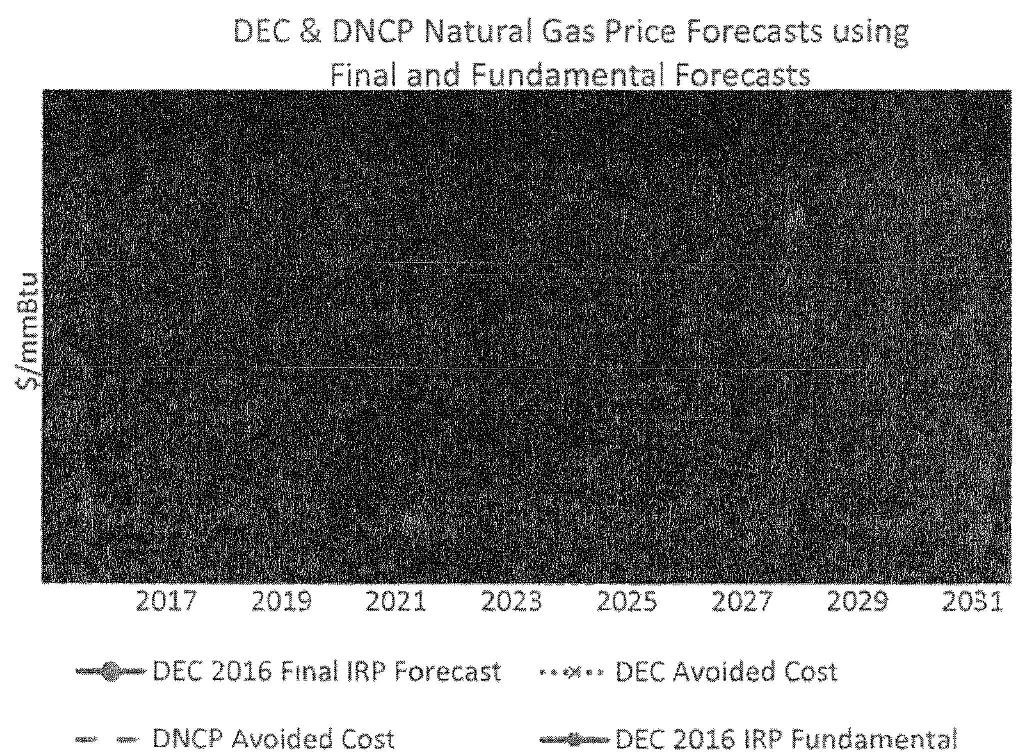
[BEGIN CONFIDENTIAL]



[END CONFIDENTIAL]

Shown below are DEC's IRP natural gas price forecast and their fundamental gas price forecast. DEC's price forecast reflects a similar pattern of sharp increases in natural gas prices as the forecast transitions to a fundamental gas forecast. If DEC and DEP had relied on only five years of forward price data as required by the Commission in the 2014 Proceeding, the price forecasts of DNCP and DEC would be far more comparable and reasonable.

[BEGIN CONFIDENTIAL]



[redacted]

[END CONFIDENTIAL]

Q. DO YOU AGREE WITH THE FUEL FORECASTS UTILIZED BY THE UTILITIES?

A. I find DNCP's reliance on forecasts from ICF, the same source utilized for its 2016 IRP, along with DNCP's use of three-year forward prices before transitioning to a fundamental price forecast to be reasonable. However, I disagree with DEC and DEP's use of ten-year forward prices, and instead recommend that the Commission direct DEC and DEP to recalculate their avoided energy rates using no more than five years of forward natural gas prices before transitioning to their long-term fundamental price forecast. This would be consistent with the Commission's directive in the 2014 Proceeding, and is also consistent with the Public Staff's comments in the 2016 IRP Proceeding.

Q. DO YOU BELIEVE THAT THE OTHER INPUTS USED BY THE UTILITIES IN THEIR CALCULATIONS OF AVOIDED ENERGY COSTS ARE REASONABLE?

A. Yes. The projections of energy sales (including EE) and peak demands, existing generation profiles, future resource portfolios, discount rates, and other inputs are the same or comparable to the inputs and assumptions used in the 15-year generation expansion plans in the utilities' IRPs. This consistency is important because the production costing model used to estimate a utility's future avoided energy costs relies on that utility's future resource expansion plans generated in its IRP. As such, it is important that the inputs used in the avoided costs model and the inputs used in the IRP model be consistent.

THRESHOLD FOR STANDARD CONTRACT ELIGIBILITY

Q. DO THE UTILITIES PROPOSE TO CHANGE THE SIZE THRESHOLD FOR STANDARD CONTRACT ELIGIBILITY?

A. Yes. Duke witnesses Snider and Bowman and DNCP witnesses Petrie and Gaskill recommend that the Commission establish the maximum size eligible for standard contracts to QFs with a capacity of 1 MW or less, which is a significant reduction from the Commission's previous standard offer threshold for QFs with a capacity of 5 MW or less.[21]

Q. WHAT DOES PURPA REQUIRE WITH REGARD TO THRESHOLD FOR AVAILABILITY OF A STANDARD OFFER?

A. Subsection 18 C.F.R. 292.304(c) provides:

(c) Standard rates for purchases.

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[21] The 5-MW threshold, which dates back to 1985, applies to hydroelectric QFs that are owned and operated by small power producers as defined in G.S. 62-3(27a) and to QFs that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass. The Commission has typically required DEC, DEP, and DNCP to offer 5-year, levelized rate options to all other QFs contracting to sell three MW or less capacity

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

Q. PLEASE BRIEFLY DISCUSS THE COMMISSION'S PAST CONSIDERATION OF THE STANDARD CONTRACT THRESHOLDS.

A. The Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by FERC regulations, and has previously rejected efforts by the utilities to lower the threshold for renewable QFs.[22] Similarly, the Commission has rejected efforts to increase the maximum cap for eligibility for the standard contract, most recently in the Phase One Order. In that Order, the Commission stated that it "must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on

[22] See, e.g., Docket No. E-100, Sub 140 (2014); E-100. Sub 100 (2004); Docket No. E-100, Sub 96 (2002); Docket No. E-100, Sub 87 (1998); Docket No. E-100, Sub 79 (1996).

customers,"[23] and found that increasing the maximum cap for eligibility for the standard contract may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers. In making this determination, the Commission noted the importance of this decision in balancing the costs, benefits, and risks to all parties and customers, and recognized that regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy. The Commission stated that there had been widespread QF development under the existing thresholds and did not find sufficient evidence at that time to indicate that the existing framework failed to comply with the requirements of PURPA or otherwise disadvantages QFs. The Commission found that without this evidence, it was "inadvisable in this docket to introduce regulatory uncertainty by changing the existing framework."[24]

Q. WHAT WAS THE PUBLIC STAFF'S POSITION ON THE PROPOSED ADJUSTMENTS TO THE STANDARD CONTRACT OFFER ELIGIBILITY LIMITS IN THE PHASE ONE ORDER?

A. The Public Staff cited prior Commission holdings that the standard QF contract options represent the appropriate balance between "the need

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[23] Phase One Order at p 21.

[24] Id. at 22.

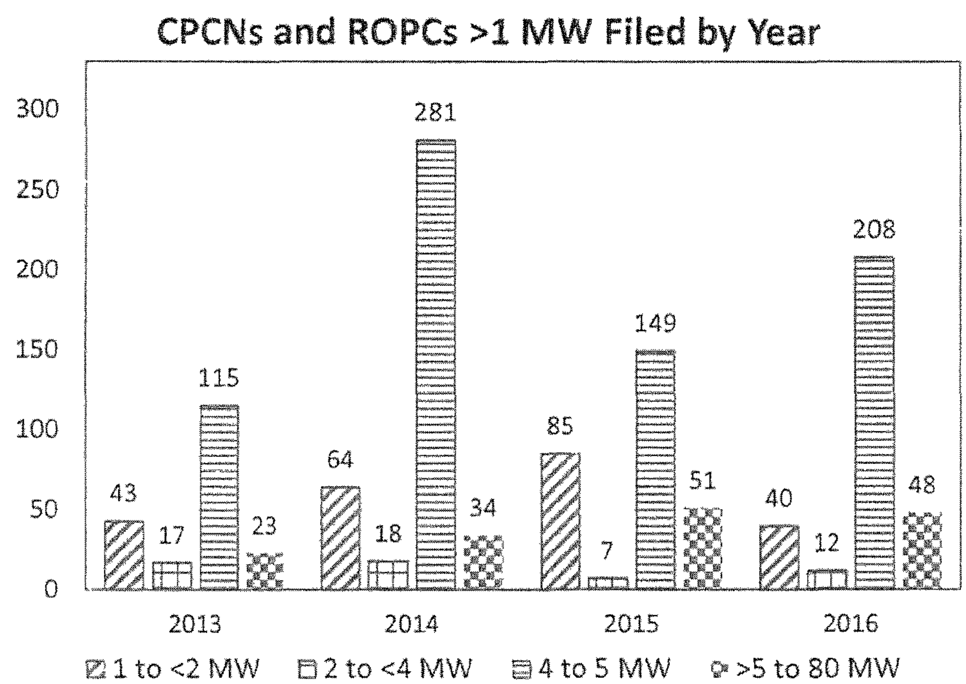
to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other."[25] We noted that setting the standard above the minimum threshold required under PURPA allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale, while providing ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options available. However, the Public Staff pointed out the significant level of QF development in North Carolina since the passage of S.L. 2007-397 (commonly referred to as Senate Bill 3) and the number of proposed QFs at or near the 5-MW standard threshold. The Public Staff further noted that negotiation of contracts by QFs not eligible for the standard offer rates with the utilities had remained challenging, lengthy, and expensive. As such, the Public Staff recommended that the Commission maintain the 5-MW standard threshold, finding that it represented an appropriate balancing point.

Q. HAVE CIRCUMSTANCES CHANGED IN RECENT YEARS TO MERIT RECONSIDERATION OF THIS ISSUE?

A. Yes. As previously discussed, the number and capacity of facilities that have been constructed or are under development in North Carolina at or near the 5-MW standard threshold over the past four

[25] Docket No. E-100, Sub 100 (2004), at pp. 10-11.

years has been tremendous. The graph below shows the number of facilities greater than 1 MW that have filed reports of proposed construction or applications for a certificate of public convenience and necessity over the past four years, clustered by size.



This significant growth of facilities from which the utilities are obligated to purchase the energy and capacity has increased the risk of potential overpayments by ratepayers. In addition, the higher penetration of resources poses operational and technical challenges to the utilities in their obligation to provide safe, reliable, and economic service to ratepayers. As such, the Public Staff believes it is appropriate for the Commission to consider modifications to the standard offer threshold.

Q. WHAT DOES THE PUBLIC STAFF RECOMMEND WITH REGARD TO ADJUSTING THE STANDARD OFFER THRESHOLD?

A. The Public Staff recommends that the Commission reduce the standard offer threshold from its current 5-MW level to a level that more currently reflects current conditions in the QF marketplace and better protects ratepayers from the risk of overpayment. To inform its recommendation, the Public Staff looked for guidance in relevant regulatory contexts on this matter. G.S. 62-110.1(g) exempts nonutility-owned generating facilities fueled by renewable energy resources less than two MW in capacity from having to obtain a certificate of public convenience and necessity (CPCN) from the Commission.[26] Further, the Commission in its adoption of a Fast Track Process in Section 3 of the North Carolina Interconnection Procedures (NCIP), allowed facilities up to two MW to be eligible for the Fast Track Process, regardless of location. Both of these provide support for the 2- MW threshold as a point where the facilities are subject to additional consideration or different treatment by the Commission, the general public through public notice requirements in G.S. 62-82, and the interconnecting utility. Reducing the threshold from five MW to two MW would represent a significant reduction from the current standard offer threshold, but at the same time still allow QFs up to two MW to

[26] Pursuant to G.S., 62-110.1(g) and Commission Rule R8-65, these facilities must still file a report of proposed construction with the Commission prior to commencing construction.

continue to take advantage of economies of scale and reduce transaction costs under the standard offer approach.

The Public Staff notes that the 1-MW limit proposed by DEC, DEP, and DNCP also represents a threshold established in other relevant regulatory contexts. For example, the Commission in its March 30, 2009, *Order Amending Net Metering Policy* in Docket No. E-100, Sub 83, established the maximum size of a facility in North Carolina that is eligible to net-meter at one MW. This position was also guided in part by G.S. 62-133.8(i)(6), which directed the Commission to consider in its adoption of rules "whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less." Further, as pointed out by Duke witness Bowman, the FERC has not required QFs below one MW to self-certify as a QF since 2010.

There are also some practical reasons for supporting a reduction in size to one MW. As stated by Duke witness Bowman, facilities one MW or below are more likely to pass the Fast Track Process than those projects between one and two MW. In response to Public Staff data requests, DEC and DEP indicated that the percentage of facilities less than one MW that passed the Fast Track screens over the past two years for each utility was 87% and 33%, respectively, while only

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11% and 5% of the facilities between one MW and two MW pass the Fast Track screens. In addition, Duke indicated that the average response time to eligible interconnection customers with regard to whether or not their project passed the Fast Track screens was approximately 8.5 days.

While the Public Staff finds support for lowering the threshold to either one MW or two MW, it appears that the 1-MW limit may have more practical significance. As indicated by witness Bowman and DNCP witness Gaskill, the reduced threshold will allow the avoided cost rates offered to more QFs to be based on more timely information, including updated capacity needs, fuel costs, and other factors that may reduce the exposure of ratepayers to potential overpayment due to changing market conditions.

Q. IF THE THRESHOLD WERE LOWERED, WHAT METHODS WOULD REMAIN AVAILABLE TO QFS TO OBTAIN FULL AVOIDED COST RATES?

A. The Commission has concluded in past avoided cost proceedings that QFs not eligible for the standard long-term levelized rates have the following three options: (a) participating in a utility's Commission-recognized competitive bidding process, if the utility has an active solicitation; (b) entering into contracts and rates "derived by free and open negotiations with the utility;" or (c) selling "as available" energy (but not capacity) at the utility's Commission-established variable energy rate. The Public Staff believes that these three options should remain available to QFs. In addition, the Public Staff notes that if the utility does not have a Commission-approved active solicitation underway, it is appropriate that any unresolved issues arising during negotiations be subject to arbitration by the Commission at the request of the utility or the QF.

Q. WHAT IS THE PUBLIC STAFF'S PERSPECTIVE ON THE PROCESS FOR NEGOTIATING QF CONTRACTS IN NORTH CAROLINA?

A. The Public Staff's investigation of this issue indicates that the process of negotiating PPA contracts can still be challenging to QFs, but that utilities and QFs are negotiating and executing these non-standard PPAs. The Public Staff notes that many of these facilities are significantly larger in size than the current standard offer threshold, indicating that QFs have sought to maximize economies of scale and available interconnection capacity in a more efficient way.

The Public Staff recognizes that the unpredictability and often protracted nature of negotiating PPAs, along with the delays in the interconnection process, may place QFs in a difficult position with

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regard to their ability to secure project financing in a timely fashion and may also raise transaction costs. While QFs maintain the right to petition for arbitration before the Commission, this process is also time consuming and adds significant transaction costs.

Similar to the Public Staff's position in the Phase One proceeding, if the Commission determines that it is appropriate to lower the threshold and to rely more heavily on negotiated PPAs, it will be necessary to streamline and improve the process to reduce transaction costs and provide a level playing field for QFs trying to negotiate PPAs. The Public Staff generally agrees with the proposal included in Duke witness Freeman's testimony regarding the establishment of reasonable contracting procedures that improve the transparency and efficiency of the negotiated PPA process, including the following.

- Specific timeframes for both parties to provide information and responses.
- The use of a standardized contract form with clear delineation of any specific changes or points of negotiation clearly identified
- Indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and be able to seek financing.

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- The opportunity for either parties to seek informal resolution of disputes or to petition for arbitration with the Commission.

The actual details of such a proposal would need to be clearly specified, and the Public Staff recommends that Duke provide additional information in its rebuttal testimony, including a discussion of how this process can be implemented in a short timeframe without creating additional delays in the ability of QFs to negotiate with the utilities.

Q. DOES THE PUBLIC STAFF BELIEVE THAT THE DETERMINATION OF AVOIDED COSTS BY A COMMISSION-APPROVED COMPETITIVE BIDDING PROCESS MAY BE A VIABLE OPTION?

A. The Public Staff supports the use of market-based approaches to determine the most cost-effective options for utilities to meet their customer's needs, as well as avoided cost rates, provided that the competitive bidding process is appropriately structured and an independent evaluator is utilized. In Docket No. E-100, Sub 122[27], the Public Staff recommended that the Commission utilize competitive bidding to a greater degree and incorporate the best practices identified in the NARUC publication entitled "Competitive Procurement

[27] Investigation Into Adopting Guidance for Electric Utilities to Assess the Capabilities of the Wholesale Market in Making Resource Additions Filed February 27, 2009.

of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices." These best practices included the following:[28]

- The procurement process should be fair and objective.
- The procurement should be designed to encourage robust competitive offerings and creative proposals from market participants.
- The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors.
- The procurement should be conducted in an efficient and timely manner.
- When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.

While the competitive bidding option has been available in North Carolina since the late 1980s, it has not been utilized on a regular basis and has not been used since the mid-1990s.[29] In recent years,

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[28] Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, prepared by the Analysis Group for National Association of Regulatory Utility Commissioners (NARUC), July 2008. Online at: http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf

[29] The Commission concluded in Docket No. E-100, Sub 57 (1989), that non-hydroelectric QFs desiring to sell generating capacity of more than 5 MW to DNCP should participate in DNCP's then current competitive solicitation. It continued this practice for DNCP until the mid-1990's. The process was formalized by the Commission in its Order establishing avoided cost rates dated June 23, 1995, in Docket No. E-100, Sub 74. In that Order, the

all three utilities have utilized request for proposals (RFPs) for various purposes, including complying with the REPS, meeting voluntary renewable energy procurement goals of certain large industrial customers, and complying with other mandates. None of these processes was, however, a Commission-recognized active solicitation for PURPA compliance purposes. Further, if the Commission were to open a separate docket as requested by Duke to establish a competitive procurement process, the Public Staff recommends that the Commission, in addition to the best practices identified by NARUC listed above, also require:

(1) That the RFP be based on needs identified in the utilities' IRPs; and.

(2) That the RFP give equal consideration for all resources.

Length of Term For Standard Contracts

Q. WHAT POSITIONS DO THE UTILITIES TAKE WITH REGARD TO THE LENGTH OF THE STANDARD CONTRACT?

Commission concluded generically that a utility could refuse to negotiate individually with non-hydroelectric QFs not eligible for the standard contracts when the utility is planning to pursue competitive bidding for its next block of capacity, and approved the use of such a competitive bidding process for one solicitation by DNCP and one by DEC. It granted DEP's motion by Order dated April 25, 1996, also in the Sub 74 proceeding, for the same relief for DEP's competitive solicitation for capacity needed in 1999.

A. In addition to reducing the threshold for availability of standard contracts to one MW, Duke and DNCP propose to reduce the maximum length of a fixed-rate standard contract to ten years.

Q. WHAT ARE THE CURRENT GUIDELINES WITH REGARD TO LONG-TERM CONTRACTS IN NORTH CAROLINA?

A. The Commission has previously concluded that the current long-term contract options serve important statewide policy interests while limiting the utilities' exposure to overpayments. In particular, the Commission has noted the following policy interests:

- G.S. 62-156(b)(1) provides that long-term contracts "shall be encouraged in order to enhance the economic feasibility of small power production facilities," which supports a decision to require long-term rate options for small hydroelectric facilities.
- G.S. 62-133.8(d) provides that "the terms of any contract entered into between an electric power supplier and a new solar electric facility or new metered solar thermal energy facility shall be of sufficient length to stimulate development of solar energy."
- The Commission in its September 29, 2005 Order in Docket No. E-100, Sub 100, stated that it believes the State policy of reducing and managing solid waste landfills set forth in G.S. 130A-309.01 to 130A-309.29 supports extending the long-term

contract options to facilities fueled by trash or methane from landfills.

- The Commission in the Sub 100 Order also noted that while there was no statute at that time dealing with hog waste or poultry waste, there was an environmental policy to be served by encouraging facilities fueled by methane from these waste products.[30]

Q. WHAT GUIDANCE REGARDING LONG-TERM CONTRACTS IS OFFERED BY THE FERC?

A. 18 C.F.R. 292.304(d)(2) provides that a QF may choose to sell energy or capacity pursuant to a legally enforceable obligation (LEO) for delivery "over a specified term." As the Commission has recognized in recent orders, the FERC has ruled that QFs have a right to fixed long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred. The FERC has never specified a minimum or maximum term to be offered by utilities to QFs. However, it is my understanding that the FERC recently held that QFs

[30] G.S. 62-133.8(e) and (f), enacted in 2008, require utilities in the state to supply a portion of their retail electric sales with energy supplies from swine and poultry waste resources, respectively. These resource mandates have proven challenging to meet, resulting in several modifications of these requirements over the past five years.

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are entitled to contracts "long enough to allow QFs reasonable opportunities to attract capital from potential investors."[31]

Q. WHAT IS THE PUBLIC STAFF'S POSITION WITH REGARD TO THE UTILITIES PROPOSAL TO CHANGE THE MAXIMUM TERM OF THE STANDARD CONTRACT?

A. The utilities argue that long-term contracts increase the risk of overpayment of avoided costs, which will be passed on to ratepayers, resulting in higher costs for all customers. In past proceedings, the Public Staff has maintained that fixed long-term rates of at least 15 years in length should be available in order to ensure that QFs could secure reasonable financing. The use of a 15-year term is also consistent with the long-range planning requirements of the electric utilities in North Carolina pursuant to G.S. 62-110.1(c)[32] which, as implemented under Commission Rule R8-60, requires each electric utility to furnish the Commission with a biennial IRP that includes forecasts and assessments for at least a 15-year period.

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[31] *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at p. 8 (Nov. 22, 2016).

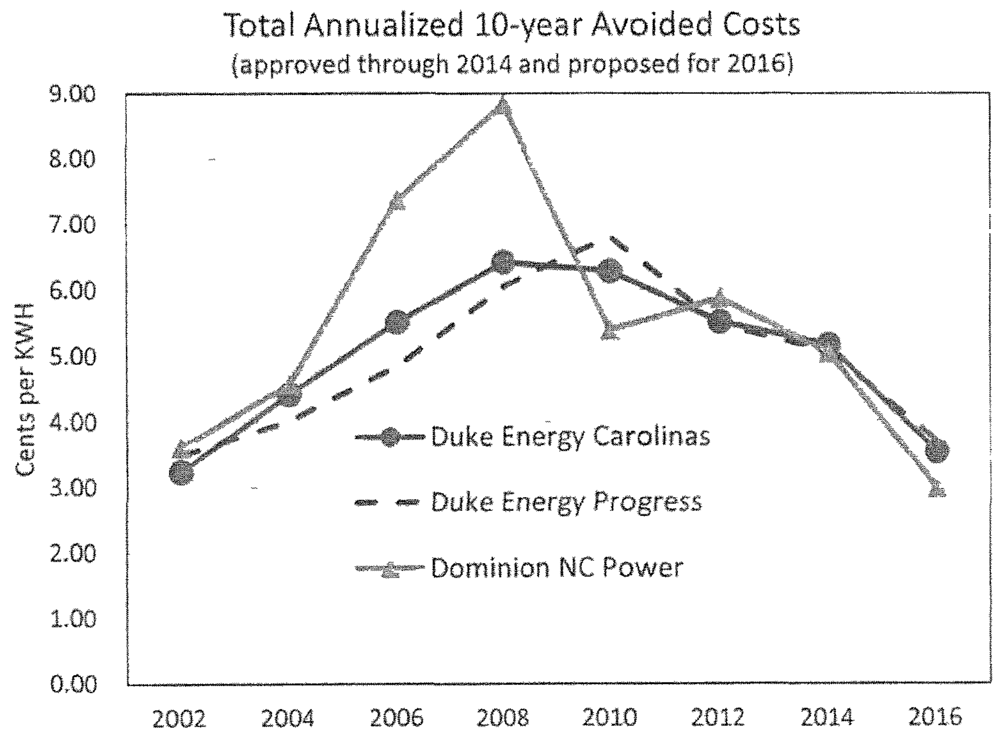
[32] G.S. 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State." The Commission's analysis is required to include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the FERC.

Given the number of currently operating facilities and solar projects in development, it appears that the use of 15-year fixed term contracts has been accepted by the financing community and has been beneficial to QFs in North Carolina.[33] The Public Staff reviewed policies in other states and found some with shorter terms and others with longer terms, but no clear standard term.

The Public Staff notes that avoided cost rates can change considerably over time, and there is always a risk of overpayment or underpayment of avoided costs. The graph below of the annualized avoided cost rates for the past eight avoided cost proceedings illustrates how the approved levelized avoided rates have evolved over time. Standard levelized contracts signed between 1998 and 2004, when rates were relatively low, resulted in contracts that were beneficial to ratepayers as rates increased in more recent years. On the other hand, the rates in standard levelized contracts signed in 2008 and 2010 are higher than the rates approved in 2012 and 2014. If avoided costs continue to fall as they have over the past three biennial proceedings, then there is a risk of overpayment and,

[33] The Public Staff notes that other State policies, including the State Renewable Energy Tax Credit, the REPS, and the 80% property tax abatement for renewable energy property, also contributed to the favorable climate for renewable energy development.

because of the growth of the solar QF industry, the magnitude of that risk will increase.[34]



Duke witness Yates testified that "because of the trend in declining energy markets over the past several years, actual incremental energy costs have been significantly lower than prior forecasts in earlier avoided cost filings." The Public Staff notes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, based largely upon forecasts of future prices, and that in many respects, the utilities' own self-build options

[34] The Public Staff notes that the reverse situation is also true: avoided cost rates could begin to rise (for example, due to an unanticipated rise in natural gas prices), resulting in contracts that were signed at lower avoided cost rates becoming increasingly favorable for ratepayers over the long-term.

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are based upon similar "uncertain" forecasts. This can be illustrated by considering two utility investments in new generating resources here in North Carolina. First, DEC's Cliffside Unit 6[35] was originally proposed to operate as a baseload unit in 2006, but due to changes in coal prices relative to natural gas, has ultimately operated more as an intermediate unit. Conversely, DEP's decision to build its natural gas-fired Richmond County Combined Cycle facility[36] in 2008 proved to be advantageous to ratepayers due to the decline in natural gas prices, and the facility has operated more as a baseload plant than as an intermediate facility as originally planned and modeled by DEP, saving customers millions of dollars in fuel costs.

As discussed by the Commission in the Phase One Order, "the FERC's order implementing Section 210 of PURPA states that the goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF. Moreover, the FERC concluded that ratepayers benefit from QFs in ways other than the direct cost because of the reduced use of fossil fuels, the addition

[35] See *Order Granting Certificate of Public Convenience and Necessity with Conditions* in Docket No. E-7, Sub 790. (March 21, 2007).

[36] See *Order Granting Certificate of Public Convenience and Necessity* in Docket No. E-2, Sub 916. (October 13, 2008).

of smaller increments of capacity, and the resulting diversity of power supply."[37]

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. This would serve to reduce the risk borne by ratepayers for overpayments over a longer term. The Public Staff believes that the utilities' proposal to limit the standard offer term to ten-year fixed PPAs is reasonable.[38] Based on its review of PPAs negotiated by the utilities, the Public Staff is aware that DEC and DEP have signed **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[37] Phase One Order at p. 20.

[38] The Public Staff notes that 18 C.F.R. 292.302(b) provides that large electric utilities must file with their State regulatory authority and make publicly available at least every two years data from which avoided costs may be derived, including the following:

> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>
> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

CONFIDENTIAL], and six of DNCP's 12 non-standard PPAs have 10-year terms, indicating that it is possible to secure financing terms shorter than 15 years. To do so, a higher interest rate or a higher level of equity investment is likely to be required. In addition, some projects that are marginally viable may not be able to secure reasonable financing.

In light of current conditions, the Public Staff agrees with the utilities' position that the use of a 10-year term is reasonable. The Public Staff recommends that the Commission continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to seek financing on reasonable terms.

Duke's Proposal to Reset Energy Rates Every Two Years

Q. **PLEASE DESCRIBE DUKE'S PROPOSAL TO ADJUST AVOIDED ENERGY RATES EVERY TWO YEARS.**

A. Duke witness Bowman testified that DEC and DEP propose to reset the energy component of avoided cost rates during each biennial avoided cost proceeding to mitigate the significant forecast risk of over- or under- projecting long-term commodity prices. She testified that this approach would protect customers from over-paying for avoided energy in future years where fuel commodity forecasts are not as certain, and provide QFs a continuing stream of revenue, as well as the potential upside benefit of increased rates if energy prices increase above forecasted levels during the 10-year contract term. She further noted that the utilities' proposal provided longer-term rates than other southern states, including Georgia, Tennessee, Alabama, and Mississippi.

Q. **DOES THE PUBLIC STAFF AGREE WITH THIS POSITION?**

A. No. The Public Staff believes that the position taken by DNCP to provide fixed 10-year energy prices as part of its standard offer rates is reasonable and consistent with PURPA's goals of encouraging QFs. This Commission in past proceedings, including the 2014 Proceeding, has acknowledged a QF's legal right to long-term fixed rates under Section 210 of PURPA and under the *J.D. Wind* Orders.[39] FERC's rationale in that case was that "in the long run,

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[39] Phase One Order at 19. See also *J.D. Wind 1*, "The FERC has "consistently affirmed the right of QFs to long term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." *J.D. Wind 1*, 130 FERC at ¶ 61,631 (2010).

'overestimations' and 'underestimations' of avoided costs will balance out."[40]

I am not an attorney, but I am aware that the FERC recently elaborated on this requirement more fully, as follows:

> [T]he Commission has long held that its regulations pertaining to legally enforceable obligations "are intended to reconcile the requirement that the rates for purchases equal to the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments, by necessity, on estimates of future avoided costs" and has explicitly agreed with previous commenters that "stressed the need for certainty with regard to return on investment in new technologies." Given this "need for certainty with regard to return on investment," coupled with Congress' directive that the Commission "encourage" QFs, a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.[41]

Based on my understanding and investigation of this issue, I do not think offering a standard offer contract with a 2-year reset on the avoided energy rates would provide sufficient "certainty with regard to return on investment" to provide a QF with a reasonable opportunity "to attract capital from potential investors." While larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment,

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[40] *Small Power Production and Cogeneration Facilities*, 45 Fed. Reg. at 12,224.
[41] Windham, *supra*

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.

The Public Staff finds that other options, 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 pricing, may provide QFs with additional certainty, while reducing ratepayers' risk of overpayment. Further, the other adjustments to the rate and terms under the standard offer as proposed by the Public Staff would significantly reduce the risk of overpayment by customers.

DNCP'S ADJUSTMENT TO AVOIDED ENERGY RATES TO REFLECT LOCATIONAL ENERGY VALUE

Q. **PLEASE DESCRIBE DNCP'S PROPOSED ADJUSTMENT TO ITS AVOIDED ENERGY RATES TO REFLECT THE LOCATIONAL MARGINAL VALUE OF THE ENERGY.**

A. DNCP proposes to adjust the avoided cost energy rates to reflect the locational energy value of the Company's North Carolina service area as opposed to the entire DOM Zone. DNCP witness Gaskill states that since the QFs in question in this proceeding are all located in North Carolina, this adjustment is designed to ensure that avoided

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energy rates for QFs located in North Carolina reflect the Company's actual avoided cost for their output.

Q. DOES THE PUBLIC STAFF AGREE WITH THIS APPROACH?

A. I think that DNCP's proposal is reasonable. DNCP provided support showing that the locational marginal prices (LMPs) for North Carolina nodes have been consistently lower than the DOM zone average LMP. Its PROMOD model, however, does not currently allow for calculation of energy rates at the nodal level. As such, it is reasonable for DNCP to amend its avoided energy costs to reflect the lower LMPs than the DOM Zone average.

<u>Avoided Energy Costs From Solar PV Systems</u>

Q. DOES THE PUBLIC STAFF PROPOSE ANY ADDITIONAL CHANGES TO AVOIDED ENERGY RATES BEYOND THOSE PROPOSED BY THE UTILITIES?

A. Yes. In the 2014 Proceeding, NCSEA witness Tom Beach referenced a study conducted by Crossborder Energy (Crossborder Study)[42] and its assessment of whether the typical diurnal profile of solar output has a higher value than a flat block of power, in light of the fact that solar output to some extent may coincide with higher

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[42] R. Thomas Beach and Patrick G. McGuire, Crossborder Energy, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 18, 2013

cost off-peak hours relative to other off-peak hours. In that proceeding, the Public Staff indicated that it agreed with witness Beach's observation with regard to the potential positive impact on off-peak energy rates. In Sub 140, the Public Staff conducted discovery where DEP, DEC, and DNCP estimated that the off-peak energy rates under Option B would increase between 8% and 10% if the definition of off-peak hours was aligned with the load profile of solar QFs.

Q. **WHAT ACTIONS DID THE COMMISSION TAKE ON THIS RECOMMENDATION?**

A. In its Phase One Order, the Commission declined to approve witness Beach's proposal to require a definition of off-peak hours to suit the load profile of solar QFs, finding that such an approach "isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources."[43]

Q. **WHY DOES THE PUBLIC STAFF BELIEVE THAT THIS CONCEPT MERITS FURTHER CONSIDERATION?**

A. The Public Staff believes that this issue is more of a modeling or allocation issue than a solar integration issue, and recommends that

[43] Phase One Order at p. 62.

the Commission reconsider this matter. From a customer perspective, the 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.

Q. PLEASE EXPLAIN WHY THE PROPOSED OFF-PEAK ENERGY RATES ARE INAPPROPRIATE FOR A SOLAR QF.

A. The existing PROSYM and PROMOD production models that generate the avoided energy rates over 8,760 hours each year are best suited to a QF that has the opportunity to generate energy during all of the on-peak and off-peak hours of the day and the night. A 24-hour dispatched QF generally has its lowest marginal costs during the late night hours and early morning hours when base load plants with the lowest marginal costs are operating. As such, the average off-peak avoided energy rates include the off-peak hours at night and early morning hours before day-break. While this average calculation of off-peak energy rates is appropriate for a landfill gas QF, it is inappropriate for a solar facility whose generation helps avoid a utility's marginal production costs during daylight hours when the marginal costs are generally higher. The Public Staff has conducted a preliminary analysis of the PJM DOM Zone LMPs and DEC's and DEP's day-ahead lambdas and finds the 8% to 10%

range proposed in the 2014 proceeding continues to be a reasonable estimate of this added benefit.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION WITH REGARD TO ANY ADJUSTMENTS TO THE OFF-PEAK RATES FOR SOLAR-BASED AVOIDED ENERGY COSTS?

A. The Public Staff recommends that DEC, DEP, and DNCP submit a separate avoided energy rate for solar that more accurately reflects the avoided marginal costs from solar QF generation during off-peak daytime hours.

<u>Overall Impact on Avoided Cost Rates</u>

Q. IN SUMMARY, CAN YOU PROVIDE AN ESTIMATE OF THE IMPACTS OF THE UTILITIES' PROPOSALS AND THE PUBLIC STAFF'S RECOMENDATIONS ON A TYPICAL FIVE MW SOLAR FACILITY?

A. Yes. To help illustrate the overall rate impact of the proposed changes on a hypothetical solar QF in North Carolina for DEC and DNCP, I used a solar generation profile based on PV Watts data to estimate the changes to the annual revenues for a solar QF under the approved 2014 avoided capacity and avoided energy rates as compared to the rates proposed by the utilities and recommended rates by the Public Staff, not including the adjustments to Duke's natural gas price forecast.

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Table 8

	Capacity Payments	Energy Payments	Total Revenue	% Change from 2014
2014 DEC Approved Rates	$162,508	$466,314	$628,823	NA
DEC Proposed Rates	$54,356	$347,669	$402,026	-36%
Public Staff Recommended	$57,889	$402,876	$460,765	-27%
2014 DNCP Approved Rates	$151,073	$456,125	$607,198	NA
DNCP Proposed Rates	$0	$321,426	$321,426	-47%
Public Staff Recommended	NA	$337,680	NA	NA

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. Since joining the Public Staff in May of 1985, I have filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. I filed testimony on the level of funding for nuclear decommissioning costs in Docket No. E-7, Sub 1026. I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual Integrated Resource Plans (IRPs). I have filed testimony on the IRPs filed in Docket No. E-100, Subs 114 and 125.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings. I have filed testimony on the avoided cost of electricity in Docket No. E-100, Subs 106, 136, and 140; and I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, E-7, Sub 790, and E-7, Sub 791.

I have filed testimony on the issue of fair rate of return in Docket Nos. E-22, Sub 333; E-22, Sub 412; P-26, Sub 93; P-12, Sub 89; G-21, Sub 293; P-31, Sub 125; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; P-100, Sub 133b; ; P-100, Sub 133d (1997 and 2002); G-21, Sub 442; W-778, Sub 31; and W-218, Sub 319. I have filed affidavits in several smaller water utility rate cases.

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001 and 1018. I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. I performed the financial analysis in the two audit reports on Mid South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency (EPA). I have published an article in the National Regulatory Research Institute's (NRRI's) Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

BY MR. DODGE:

Q Mr. Hinton, did you prepare a summary of your testimony?

A Yes.

Q Would you please provide it at this time?

A Yes.

MR. DODGE: And copies of the summaries for all three of our witnesses have already been distributed.

(WHEREUPON, the summary of **JOHN ROBERT HINTON** is copied into the record.)

BIENNIAL DETERMINATION OF AVOIDED COST
DOCKET NO. E-100, SUB 148

SUMMARY OF JOHN ROBERT HINTON

The purpose of my testimony is to comment and make recommendations to the Commission regarding the proposed avoided cost rates filed by Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion North Carolina Power (DNCP) (collectively, the utilities) in this docket. I describe some of the trends in qualifying facility (QF) development experienced in North Carolina in recent years, including observations on the tremendous growth in the number and capacity of QF facilities that have been constructed or are under development, and the need to re-evaluate the use of the peaker method and other issues to reduce the potential exposure of ratepayers to overpayment. My testimony recommends proposed changes in the following areas:

Avoided Capacity Rates: My testimony supports the continued use of the peaker methodology, modified for the purposes of this proceeding to provide a capacity payment only during those times when the utility's IRP shows a need for capacity. I also discuss the historic basis for the Performance Adjustment Factor (PAF), and recommend that the Commission revise the PAF for non-hydroelectric facilities from 1.20 to 1.16, consistent with the analysis conducted by Public Staff witness Dustin Metz. In addition, I propose the use of a 40% Summer and 60% Non-Summer seasonal allocation factor for capacity payments for DEC and DEP.

Avoided Energy Rates: I recommend that the Commission support DNCP's fuel forecasting methodology, which is based on the use of three years of forward prices of natural gas that is blended with a long-term fundamental forecast, but recommend that

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the Commission reject DEC's and DEP's reliance on ten-year forward natural gas prices and limit the use of forward prices to 5 years. I also indicate my support for DNCP's adjustment for locational energy value of QF generation; but reject DEC's and DEP's proposal to "reset" its avoided energy rates every 2 years. I also discuss further adjustments to the utilities' proposed off-peak avoided energy rates to reflect the diurnal nature of energy production for solar facilities.

Standard offer terms: My testimony further recommends that the Commission revise the capacity thresholds for standard offer contracts from its current 5-MW level to a 1 MW size limit, as recommended by DEC and DEP, and that the Commission reduce the maximum standard contract length from 15 years to 10 years, as recommended by the utilities.

The Public Staff believes that these changes are appropriate in light of the continued and expected QF development taking place in North Carolina, and that the changes, taken as a whole, help to balance the State's obligations under PURPA while reducing potential ratepayer risk.

This concludes my summary.

MR. JOSEY: I'll start with Mr. Lucas.

DIRECT EXAMINATION

BY MR. JOSEY:

Q Mr. Lucas, could you please state your name and address for the record?

A (MR. LUCAS) Jay Lucas, 430 North Salisbury Street, Raleigh, North Carolina.

Q And by whom are you employed and in what capacity?

A I'm an Engineer with the Public Staff's Electric Division.

Q And did you cause to be filed on March 28, 2017, in this docket testimony consisting of 16 pages?

A Yes.

Q Do you have any correction -- changes or corrections to your direct testimony at this time?

A No.

MR. JOSEY: Chairman Finley, at this time I would move that Mr. Lucas' direct testimony be entered into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Lucas' direct prefiled testimony filed on March 28, 2017, consisting of 16 pages is copied into the record as if given orally from the stand.

MR. JOSEY: Thank you.

(WHEREUPON, the prefiled direct testimony of **JAY B. LUCAS** is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of		
Biennial Determination of Avoided Cost	)	TESTIMONY OF
Rates for Electric Utility Purchases	)	JAY B. LUCAS
from Qualifying Facilities – 2016	)	PUBLIC STAFF – NORTH
	)	CAROLINA UTILITIES
	)	COMMISSION

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Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Jay B. Lucas. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix A to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the February 21, 2017, testimony of Kendal Bowman and Gary Freeman filed by Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), collectively "Duke", regarding proposed changes in the requirements for a qualifying facility (QF)[1] to establish a legally enforceable obligation (LEO) in North Carolina.[2]

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[1] A QF is a producer of electricity that meets the requirements of the Federal Energy Regulatory Commission (FERC) for ownership, size, and efficiency and from which

Q. WHAT IS A LEO?

A. Under the Public Utility Regulatory Policies Act of 1978 (PURPA),[3] a QF can sell its generation to a utility "as available" or "pursuant to a legally enforceable obligation."[4] For sales pursuant to a LEO, the QF can choose to have prices based on avoided costs calculated at the time the QF establishes the LEO or at the time the QF commences delivery to the utility.[5] The date of the LEO determines which avoided cost proceeding the QF can use to establish rates for energy and capacity.

Q. WHAT ARE THE CURRENT REQUIREMENTS FOR ESTABLISHING A LEO IN NORTH CAROLINA?

A. Each state is allowed to develop its own standard as to when a LEO is formed, as long as the standard does not conflict with the FERC's regulations. Accordingly, in its December 17, 2015 Order in Docket No. E-100, Sub 140 (Sub 140 Order), the Commission set the current requirements by which a QF may establish a LEO:

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utilities in some circumstances must purchase energy at their avoided cost rates. The complete criteria for a QF are provided in Chapter 18, Section 292, of the Code of Federal Regulations.

[2] The Public Staff notes that Dominion North Carolina Power (DNCP) did not propose changes to the LEO requirements, but believes that to the extent the Commission modifies the requirements for Duke, it is appropriate to make similar changes to the LEO requirements applicable for QFs seeking to locate in DNCP's service territory.

[3] Pub. L. No. 95-617, 92 Stat. 3117.

[4] 18 C.F.R. §292.304(d).

[5] *Id.*

(1) self-certify with FERC as a QF, if required;

(2) file a report of proposed construction or obtain a certificate of public convenience and necessity (CPCN) from the Commission to construct the generator; and

(3) indicate its commitment to sell its output to a utility by submission of a Notice of Commitment Form as required by Finding of Fact No. 24 in the Sub 140 Order.

Q. PLEASE SUMMARIZE DUKE'S CONCERNS REGARDING THE EXISTING LEO CRITERIA.

A. Duke contends that the existing LEO threshold is too low and allows QFs to lock in avoided cost rates long before they are actually generating electricity. Duke asserts that the existing criteria to establish a LEO can be easily met by a QF, but in practicality, the criteria do not commit the QF to build a generator at all. Duke states that, in theory, the 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. In reality, however, the utility cannot avoid plans to construct future generation based upon the LEO. Further, the QF rarely knows the interconnection costs on the LEO date or whether building the facility could possibly be prohibitively expensive or time consuming. Thus, Duke states its customers bear the risk of providing a LEO to a QF that may not be able to meet its power delivery date.

This risk arises, in part, because the interconnection process often takes far more time than contemplated by the North Carolina Interconnection Procedures (NCIP) adopted in Docket No. E-100, Sub 101, due to the number of QF projects in the interconnection queue and the imposition of additional requirements to address reliability concerns. These delays, 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. WHAT CHANGES HAS DUKE PROPOSED TO THE CURRENT REQUIREMENTS FOR ESTABLISHING A LEO?

A. Duke's proposed changes to the requirements for establishing the LEO are described in Duke's Joint Initial Statement filed on November 15, 2016, and the testimony of witness Gary Freeman. For QFs with a capacity of 1 megawatt (MW) or less, Duke proposes that the LEO be established when the QF:

(1) files a report of proposed construction with the Commission;

(2) submits a complete interconnection request to the Company; and

(3) submits a Notice of Commitment to the Company.

Duke has proposed that 1 MW be the maximum capacity of a QF to qualify for standard purchased power rates.

Duke proposed in its Joint Initial Statement that QFs with a capacity greater than 1 MW not be able to establish a LEO until they have executed and returned a Facilities Study Agreement under Section 4.4 of the NCIP, which would occur after completion of the System Impact Study requirement in Section 4.3 of the NCIP. In his testimony, Mr. Freeman proposes an alternative: that Duke work with the Public Staff and other interested parties to create formalized contracting procedures that would also be determinative of when a LEO is established. The key components of the proposed procedures are:

(1) the QF submits specific project information to Duke with a request for non-binding pricing;

(2) Duke provides non-binding pricing and a draft purchase power agreement (PPA) within 30 calendar days;

(3) the non-binding PPA is available for 60 calendar days; and

(4) Duke and the QF negotiate a PPA in good faith, and if the parties reach agreement, Duke will provide a final executable interconnection agreement (IA), which would be executed and returned back to the Company within 15 calendar days.

The final executed PPA would provide the QF with an additional 60 calendar day "post-execution due diligence period," after which it would be liable for liquidated damages if it delays construction or decides not to build the facility after committing to do so. A LEO would be established by executing a PPA, or by the Commission through arbitration or a complaint proceeding

Q. WHAT DOES THE PUBLIC STAFF RECOMMEND FOR ESTABLISHING THE LEO?

A. For QFs eligible for the standard contract, the Public Staff agrees with the recommendations of Mr. Freeman as described above. For QFs not eligible for the standard contract, the Public Staff does not agree with Duke's proposal to tie the establishment of a LEO to execution of the PPA. The Public Staff recommends that the Commission adopt the same criteria for establishing a LEO as those Mr. Freeman recommended for smaller QFs, but with two additional requirements, as follows:

- First, the QF must be a Project A or B in the interconnection queue, as described in Section 1.8 of the NCIP.
- Second, the LEO would not be established until the earlier of the QF's receipt of the utility's System Impact Study for the QF project or 105 days after the QF submits a complete interconnection request to the Company.

Q. PLEASE EXPLAIN WHY YOUR RECOMMENDATION WOULD ONLY APPLY TO PROJECTS DESIGNATED AS A OR B.

A. Under NCIP Section 1.4.2, queue position is established based on the date- and time- stamp of an interconnection request, and pursuant to NCIP Section 1.8, to the extent there are interdependent projects in the queue, Project A and B status represents the highest queue position on that circuit or feeder.[6] Only projects designated as A or B are evaluated in the interconnection study process, while other projects in the queue, Project C and thereafter, are on hold. Until a project has begun progressing through the study process, i.e., moved to Project A or

[6] The Public Staff notes that the utility does not have any control over whether interdependency issues exist between QFs in the interconnection queue, since the decision to submit an interconnection request for a specific location is made by the QF.

B status, the project owner has little or no information regarding whether it is technically or economically feasible to interconnect at its requested point of interconnection. As such, I recommend that projects designated as Project C status or below be ineligible to establish a LEO until such time as their status changes to Project A or B.

Q. **PLEASE EXPLAIN WHY YOU RECOMMEND THAT FOR QFS NOT ELIGIBLE FOR A STANDARD CONTRACT, A LEO NOT BE ESTABLISHED UNTIL THE EARLIER OF THE QF'S RECEIPT OF THE SYSTEM IMPACT STUDY OR 105 DAYS AFTER THE QF SUBMITS A COMPLETE INTERCONNECTION REQUEST TO THE COMPANY.**

A. Under the NCIP, a utility should complete the System Impact Study for a QF with Project A or B status within 105 days of the interconnection request submission, assuming all of the timeframes in the NCIP are followed. Upon receiving the System Impact Study results, a QF owner should have information on the feasibility, costs, and time required for its proposed interconnection, and therefore be in a better position to evaluate the viability of the project and commit to building the facility than at the beginning of the interconnection process.

Duke's initial proposal would prohibit a QF from being able to establish a LEO until after it submitted a Facilities Study Agreement. Before a Facilities Study Agreement can be submitted, however, the utility must complete a System Impact Study. This process leaves much of the timing and control of the process to the utility. Under the NCIP, the utility has 105 days to provide the System Impact Study. However, in a number of cases, these System Impact Studies are taking much longer. Duke indicated in a data response to the Public Staff that for projects entering into the System Impact Study step of the interconnection process from March 1, 2015, through December 31, 2016, the interval for completion of the System Impact Study has varied from one day to over a year, with a number of those studies still awaiting completion. In response to a data request, Duke provided the following estimates of the current interval to complete the System Impact Study for different sized solar projects:

- 1 MW – 94 Days (77 days DEP and 193 days DEC)
- 5 MW – 147 Days (139 days DEP and 293 days DEC)
- 20 MW – 197 Days (197 DEP days and N/A DEC)[7]

Under the Public Staff's proposal, establishment of a LEO would occur the earlier of when the System Impact Study is completed or

[7] Days are gross business days and do not reflect tolling when waiting on a developer response.

105 days has passed from the date of interconnection proposal submittal. If the NCIP timeframes are met, the QF will have received the results of the System Impact Study and have information allowing it to make a more informed commitment.

I have reviewed the recent *FLS Energy* case, where the FERC found that a requirement that allowed the utility "to control whether and when a legally enforceable obligation exists" was inconsistent with PURPA.[8] While I am not an attorney, adding this 105-day requirement appears to be more consistent with the *FLS Energy* case because it allows the QF to control if and when it established its LEO.

Q. IN ADDITION TO TYING THE LEO TO THE NCIP TIMEFRAMES, WHAT ADDITIONAL INDICIA OF COMMITMENT DOES THE PUBLIC STAFF'S PROPOSAL REQUIRE?

A. In order to initiate the timeframes called for in the NCIP, a QF must submit a complete interconnection request pursuant to NCIP Section 1.4, which requires detailed information on the facility, design work and development of an electrical one-line diagram, and verification of site control. All of these steps require expenditures of resources and time by the applicant. In addition, to the extent this

[8] In re: FLS Energy, Inc., Notice of Intent Not to Act and Declaratory Order, 157 FERC ¶ 61, 211, at paragraph 23, (December 15, 2016) (*FLS Energy* case)

information is later modified by the QF in a material way, the QF may have its queue position withdrawn and the interconnection customer would potentially have to restart the process.[9] Therefore, a material modification could affect the LEO.

Further, upon entering the interconnection process, QFs that are larger than 2 MW or did not pass the Fast Track process are required to pay a deposit of $20,000 plus $1 per kW_{AC}. While a portion of the deposit may be refundable should the QF decide to terminate the interconnection process,[10] submission of this amount of money does provide an indication of the QF's commitment to proceed through the interconnection process.

Q. WHAT OTHER BENEFITS DO USING THE TIMEFRAMES IN THE NCIP PROVIDE TO BOTH THE UTILITIES AND QFS?

A. Interconnection is an integral part of developing new QF generation, and it is impossible for a QF to be able to make informed decisions about the viability of its project without obtaining information on interconnection costs and scheduling. This information can only be obtained when the project has reached a Project A or B position in the interconnection queue, which is

[9] Material modifications are discussed in Section 1.5 of the NCIP.

[10] Section 6.3 of the NCIP provides that following the withdrawal of an interconnection request, the utility is required to provide a final accounting report and refund any portion of the deposit not already utilized in conducting the studies or any system upgrade or interconnection facilities costs.

largely within the control of the utility. If QFs in the interconnection queue in North Carolina were not experiencing delays beyond the established timeframes, many of the concerns regarding premature establishment of a LEO would be less significant. Tying the LEO to the NCIP timeframes provides an incentive to utilities to move projects through the process in as timely fashion as possible, which would help ensure that the utility's payments to a QF reflect current avoided costs. In the event that the current delays in the interconnection queue are resolved, a QF may be presented with a System Impact Study and have to commit sooner than 105 days. In that case, not only should the QF be much better situated to make a commitment based on information received from the System Impact Study and the rates for which it will be eligible, but the rates would more closely reflect current avoided costs.

Q. DOES THE PUBLIC STAFF PROPOSE ANY OTHER CHANGES TO THE NOTICE OF COMMITMENT FORM?

A. Yes. Duke witnesses Yates, Bowman, Snider, and Freeman discuss the issue of "stale" rates, i.e., that the rates for which a QF is eligible at the time it establishes a LEO using the Notice of Commitment Form may no longer be representative of the utility's current avoided costs at the time the QF begins delivering power. The Public Staff agrees with many of these concerns and believes that the adjustments it has proposed above, along with other recommendations in the testimonies of Public Staff witnesses Hinton and Metz, help address part of that concern. The Public Staff believes that its recommendations will create a LEO policy fair both to ratepayers and QFs, particularly in periods of declining avoided cost rates like North Carolina has been experiencing for the past six years. However, in the event that avoided cost rates begin to increase, a QF may instead wish to delay its establishment of a LEO, or even allow a previously executed Notice of Commitment to expire in order to establish a new LEO at the higher rates. In this case, a change in the LEO date could result in customers losing the benefit of the lower rates to which the QF had previously committed, and even potentially allow gaming of rates by a QF at customer expense. The Public Staff proposes that the LEO form be modified to include a provision that limits a QF that withdraws its Notice of Commitment from being able to establish a new LEO for two years from the date of the withdrawal. Instead, the QF should be limited to the utility's "as available" energy rates during that time.

Q. ARE THERE ANY OTHER PROVISIONS OF THE STANDARD CONTRACT THAT PROTECT RATEPAYERS FROM STALE RATES RESULTING FROM DELAYS IN THE

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INTERCONNECTION PROCESS, PPA EXECUTION, AND CONSTRUCTION?

A. Yes. The current terms and conditions of Duke's standard contract, which Duke has not proposed to change (except for the docket number), provide:

> The Fixed Long Term Credit rates on this schedule are available only to otherwise eligible Sellers that establish a Legally Enforceable Obligation on or before the filing date of proposed rates in the next biennial avoided cost proceeding, provided eligible Seller begins delivery of power no later than thirty (30) months from the date of the order approving avoided cost rates in Docket No. E-100, Sub 140, but may be extended beyond 30 months if construction is nearly complete and Seller demonstrates that it is making a good faith effort to complete its project in a timely manner.

This 30-month termination provision should provide some protection for ratepayers if a QF is not making reasonable progress on the project. Additionally, the Notice of Commitment form provides that a LEO terminates:

- for a standard contract QF, 30 days after the utility delivers an executable PPA, or
- for a non-standard contract QF, six months after the utility delivers a PPA, subject to extension until the interconnection agreement is tendered or tolling if an arbitration is filed.

Q. DOES THE PUBLIC STAFF SUPPORT DUKE'S PROPOSAL TO DEVELOP PUBLICLY AVAILABLE PROCEDURES FOR THE NEGOTIATION OF NON-STANDARD PPAS?

A. Yes. As discussed in Public Staff Hinton's testimony, the Public Staff believes that the development of formalized procedures for negotiation of PPAs could provide both parties with more certainty and create a more streamlined process.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Jay B. Lucas

I graduated from the Virginia Military Institute in 1985, earning a Bachelor of Science Degree in Civil Engineering. I also graduated from the Virginia Polytechnic Institute and State University in 1991, earning a Master of Science degree in Environmental Engineering. I have 31 years of engineering experience, and since joining the Public Staff in January 2000, have worked on utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation. I am a licensed Professional Engineer in North Carolina.

BY MR. JOSEY:

Q Mr. Lucas, did you prepare a summary of your testimony?

A Yes.

Q Would you please provide it at this time?

A Yes.

(WHEREUPON, the summary of **JAY B. LUCAS** is copied into the record.)

MR. JOSEY: Thank you. Switching to Mr. Metz.

DIRECT EXAMINATION

BY MR. JOSEY:

Q Mr. Metz, could you please state your name and your address for the record?

A (MR. METZ) My name is Dustin Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q By whom are you employed and in what capacity?

A I am an Engineer with the Public Staff, Electric Division.

Q Did you cause to be filed on March 28, 2017, in this docket testimony consisting of 22 pages and three exhibits, including one confidential exhibit?

A Yes, that is correct.

Q Do you have any changes or corrections to your direct testimony at this time?

A No, I do not.

MR. JOSEY: Chairman Finley, at this time I would move that Mr. Metz' direct testimony be entered into the record as if given orally from the stand, and the exhibits be marked as prefiled.

CHAIRMAN FINLEY: Mr. Metz' direct prefiled testimony filed on March 28, 2017, consisting of 22 pages is copied into the record as though given orally from the stand, and his three exhibits are marked for identification as premarked in the filing, and to the extent the exhibit is marked confidential it shall be so designated in the transcript.

MR. JOSEY: Thank you. I would also like to note for the Court Reporter's convenience that Mr. Metz' Exhibit 1 is confidential and pages 11 -- page 11 of Mr. Metz' testimony also contains confidential information.

Public Staff Witness Metz Confidential Exhibit 1
(Identified)

Public Staff Witness Metz Exhibits 2 and 3
(Identified)

(WHEREUPON, the prefiled direct testimony of **DUSTIN R. METZ** is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

In the Matter of	)	TESTIMONY OF
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	)	DUSTIN R. METZ
	)	PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
	)	
	)	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

Testimony of Dustin R. Metz

On Behalf of the Public Staff

North Carolina Utilities Commission

March 28, 2017

Q: **PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.**

A: My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q: **BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A: My qualifications and duties are included in Appendix A.

Q: **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A: The purpose of my testimony is to present the results of my review of the initial statements and exhibits filed by Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), collectively "Duke", and Dominion North Carolina Power (DNCP), collectively "the utilities" or "the Companies", on November 15, 2016, as well as the testimony and exhibits of the utilities filed February 21, 2017, in Docket No. E-100, Sub 148, the Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016 (2016 Proceeding). Specifically, my review focused on the utilities' proposals related to the operational impact of qualifying facilities (QFs) on the utilities' electric systems.

Based upon my review of the statements, testimony, and subsequent responses to Public Staff data requests, I conclude that the proposed changes made by the Companies in order to meet the required North American Electric Reliability Corporation (NERC) standards and associated requirements set forth in each of their respective Balancing Authority (BA) areas are reasonable and consistent with their obligation to ensure the safe operation of the electrical system (the "grid") in a cost-effective manner for ratepayers.

Q: WHAT SPECIFIC CONCERNS DO YOU ADDRESS IN YOUR TESTIMONY?

A: I address issues related to current and pending NERC reliability standards; utility curtailment of intermittent generation during system emergencies;

proposed adjustments to the performance adjustment factor (PAF); and the line loss adder.

Q: WHAT ISSUES HAVE THE UTILITIES RAISED WITH REGARD TO NERC RELIABILITY STANDARDS?

A: In his direct testimony filed on February 21, 2017, Duke witness John Samuel Holeman III discusses DEC's and DEP's responsibilities as BAs to comply with NERC's Reliability Standards. Specifically, witness Holeman cites BAL-001 (Real Power Balancing Control Performance), BAL-002 (Disturbance Control Performance), and BAL-003 (Frequency Response and Frequency Bias Setting) standards as being of particular concern at this time.

The purpose of BAL-001 is to control interconnection frequency within defined limits by balancing real power demand and supply resources in real time.

The purpose of BAL-002 is to ensure that the BA is able to utilize its contingency reserve to balance resources and demand to return interconnection frequency within the defined limits following a reported disturbance. Each BA is required to have access to, and operate when needed, resources to respond to disturbances and restore demand/supply balance within 15 minutes of the start of a disturbance event. The BA must have firm contingency reserves and dependable capacity designated for deployment to meet disturbances. Variable and intermittent resources would not qualify as contingency reserve; rather, they exacerbate the need for contingency reserves.

The purpose of BAL-003 is to require sufficient frequency response from the BA to maintain interconnection frequency within predefined bounds by arresting frequency deviations and supporting frequency until it is restored to its scheduled value. Each BA is required to have a certain amount of resources available to maintain interconnection frequency within the predefined bounds.

Together, these standards help to ensure reliability of each interconnection. A violation of any of these standards for more than 30 consecutive minutes constitutes a system emergency, which could damage generators, lead to load shedding, and, in the worst case scenario, collapse the system across the entire Eastern Interconnection, not just within DEC's or DEP's balancing areas.

Q: **ARE DEC AND DEP REQUIRED TO COMPLY WITH THE NERC BAL STANDARDS?**

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A: Yes. According to the NERC website,[1] these standards are both mandatory and subject to enforcement according to Section 215 of the Federal Power Act. In order to meet these standards, DEC and DEP must designate certain baseload, intermediate, and must-run generating units that can operate at no less than a minimum reliable output level in order to provide frequency and other regulation support to the BAs, and to meet intermediate peak loads.

Q: DO YOU AGREE THAT THE SIGNIFICANT INCREASE IN INTERMITTENT GENERATION IN NORTH CAROLINA POSES CHALLENGES TO DEC AND DEP MEETING THE NERC BAL MANDATORY STANDARDS DISCUSSED ABOVE?

A: Yes. Because of utilities' limited ability to control the "must take" output of QFs' intermittent generation, utilities face situations of both over-supply and under-supply to meet the demands within their BAs, which must be dealt with in real time via the contingency reserves within their control. An over-supply of generation results in over-frequency conditions within the interconnection, and under-supply of generation results in under-frequency conditions. As the quantity of the "must take" generation mandated by the

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[1] North American Electric Reliability Corporation, United States Mandatory Standards Subject to Enforcement: http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States. Date last accessed: March 20, 2017.

Public Utilities Regulatory Policies Act of 1978 (PURPA) increases within their respective BAs, both DEC and, in particular, DEP face increasing operational challenges as they seek to maintain the proper amount of contingency reserves that can be "ramped up" and "ramped down" in real time to meet resulting demand/supply imbalances.

In response to discovery from the Public Staff, DEP provided its internal reference manual that is being implemented for system operations regarding excess energy events and curtailment.[2] This System Operations Reference Manual Carolinas (SORMC) was provided confidentially, therefore I will discuss it at a high level. The SORMC lists a sequence of options that system operators are allowed to utilize during excess energy events. Some of the options include generation reduction of nuclear units, non-utilization of hydro units, generation reduction of cogeneration facilities, and pursuit of off-system sales to reduce thermal cycling of fossil units.[3] I am also aware that DEC and DEP are in the process of developing operating procedures that will, among other things, include curtailment provisions for all generation sources, including QF generation, in order to avoid violations of NERC balancing standards.

[2] SORMC-GOP-030 Rev 15, Last Amended and Approved on January 19, 2017

[3] Thermal cycling events of certain generation plants, i.e., coal, may result in increased tube leaks, and therefore incur higher maintenance costs and increase the potential for extended outages.

It is also noteworthy to mention that NERC can implement new or revised standards at any given time. It is the Companies' responsibility to implement any such new or revised NERC standards to ensure no related violations occur. Currently, there are 29 NERC standards subject to future enforcement between April 2017 and January 2018.[4] Among these 29 pending standards is a revision to BAL-002 (denoted BAL-002-2) which will become effective January 1, 2018. Included in this revision is an explicit discussion of the requirement of the BA to return its Area Control Error (ACE)[5] to zero following a balancing contingency event.[6] As of the date of this filing, I have not had sufficient time to fully analyze the impacts of this revised BAL standard, but based upon interviews with DEC and DEP personnel, Duke is making provisions in its operational procedures (or equivalent) to address these upcoming changes. I recommend that Duke address BAL-002-2, its effects on system operations, and the new operational procedures in its rebuttal testimony.

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[4] http://www.nerc.net/standardsreports/standardssummary.aspx, March 2017. Note: the drop down menu at the top of the link will allow the user to navigate between current and future enforcement standards.

[5] Area control error (ACE) is the instantaneous difference between a BA's net actual and scheduled interchange, taking into account the effects of frequency bias.

[6] Overgeneration, as discussed by Witness Holeman, would constitute a balancing contingency event See Witness Holeman's Testimony on the discussion of ACE, pp. 30-32.

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Q: WHAT IS YOUR OPINION OF THE UTILITIES' ASSERTION THAT INTERMITTENT QF GENERATION PRESENTS OPERATIONAL CHALLENGES TO THEIR ELECTRICAL SYSTEMS?

A: I agree that DEC and particularly DEP face unique challenges in the continued operation of their electrical grids as increasing amounts of PURPA-mandated "must take" generation and non-dispatchable generation are being added. The impacts to date have been, but are not limited to: power flowing from distribution circuits back onto the transmission system (reverse, or "negative," power flows); excess energy generated at times when there is insufficient system load (overgeneration events); difficulty planning for day-ahead operations due to the growth of variable generation; difficulty of real time operation of their electrical systems due to high levels of intermittent generation relative to load; more frequent operation of ancillary resources to meet the increasing ramp-up and ramp-down needs of their systems; and the need to sell or "dump" excess generation at a loss.[7]

These impacts are already occurring with existing levels of interconnected solar generation. Continued growth in unconstrained and non-dispatchable generation will only serve to exacerbate the current system challenges.

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[7] DEP response to Public Staff Data Request No. 3-1, March 2017 See Public Staff Witness Metz Confidential Exhibit 1.

Because DEC and DEP, as BAs, are required to operate their respective electrical systems in compliance with NERC standards and are integral members of the Eastern Interconnection, they should have the ability to exercise curtailment of intermittent QF generation during system emergencies in order to maintain the safe and reliable operation of their respective systems.

Q: WHAT IS A SYSTEM EMERGENCY?

A: According to 18 CFR 292.101(b)(4), a system emergency "means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property."

Q: DOES DUKE HAVE THE RIGHT TO CURTAIL IN A NEGOTIATED CONTRACT?

A: A negotiated contract may have language in it that would allow the system operator to contact the generator and request the generator to decrease or cease generation at that facility. This action is commonly referred to by Duke Energy as "Dispatch Down" instruction. A dispatch down instruction is a form of curtailment that may occur during emergency and non-emergency conditions.[8] The Public Staff reviewed negotiated contracts filed by Duke and generally found that the contracts provide that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q: HAS DUKE UTILIZED THIS DISPATCH DOWN INSTRUCTION LANGUAGE WITH QFS?

A: Yes. In response to Public Staff data requests, DEP indicated that it has utilized its curtailment or dispatch down instruction for certain QFs, primarily

[8] Duke's negotiated contracts define "emergency condition" as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

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during night-time hours to address excess energy conditions during those hours when the system was at the Lowest Reliability Operating Level.

Q: ARE UTILITIES ALLOWED TO CURTAIL QFS DURING A SYSTEM EMERGENCY?

A: Yes. Under 18 CFR 292.307(b), utilities can discontinue purchases during system emergencies "if such purchases would contribute to such emergencies[.]" However, each QF being curtailed in a system emergency "must be treated on a nondiscriminatory basis in any load shedding program – *i.e.*, on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption of service."[9]

Q: DOES AN IMMINENT VIOLATION OF A NERC BAL STANDARD CONSTITUTE A SYSTEM EMERGENCY?

A: While neither the Federal Code nor any FERC ruling has expressly stated that an imminent violation of a NERC BAL Standard constitutes a system emergency, I believe that an imminent violation of any of the BAL Standards would constitute a system emergency. As stated earlier in my testimony, these standards were enacted to ensure that the grid would remain stable

[9] Docket No. RM79-55, Order 69.

in order to prevent significant disruptions of service to customers, not just to the Duke BAs, but also to the entire Eastern Interconnection.

Q: ARE UTILITIES CURRENTLY ALLOWED TO CURTAIL QFS TO AVOID VIOLATING A NERC BAL STANDARD?

A: Yes, I believe so. If a utility were to face an imminent violation of a NERC BAL Standard, which I believe constitutes a system emergency, then the utility would be authorized under 18 CFR 292.307(b) to curtail QFs on an nondiscriminatory basis.

Q: WHAT STEPS DOES THE PUBLIC STAFF RECOMMEND TO ENSURE THAT A DECISION BY A UTILITY TO CURTAIL QFS IS MADE DUE TO SYSTEM EMERGENCY CONDITIONS AND ON A NONDISCRIMINATORY BASIS?

A: The Public Staff is currently in discussions with the Duke about filing its QF curtailment guidance documents with the Commission, along with requirements on how curtailment events would be reported, and what information would be included in each report.[10] Further, the Public Staff believes that the Commission should: affirm that utilities have the authority

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[10] DEP, in response to Public Staff Data Request Response 3-2, March 2017 states: "DEP has a team of personnel working on processes and procedures by which DEP, as the system operator, would communicate and implement dispatch down and dispatch up instructions." See Public Staff Witness Metz Exhibit 2

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.

Q: HAVE EITHER DEC OR DEP VIOLATED ANY OF THE NERC BAL STANDARDS OR EXPERIENCED ANY OVER- OR UNDERGENERATION EVENTS?

A: According to their response to Public Staff Data Request 6-3, neither DEC nor DEP has been found in violation of any NERC BAL Standards at this time. DEP did report, however, 33 overgeneration events during 2016 and has already had 19 instances of overgeneration in 2017 through February 21.[11]

Q: HOW HAS DEP DEALT WITH THOSE OVERGENERATION EVENTS?

A: DEP has been able to sell the excess generation to DEC through the current Joint Dispatch Agreement (JDA) between the two companies via a non-firm transmission path.

[11] Public Staff Data Request Response 3-1, March 2017. See Public Staff Witness Metz Confidential Exhibit 1

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Q: WILL DEP BE ABLE TO CONTINUE THIS PRACTICE IN THE FUTURE?

A: No. Witness Holeman stated that once DEP reaches 2,200 MWs of solar generation, DEP will be unable sell all of the excess energy to DEC to solve the problem. DEP expects that it will reach 2,200 MWs by either late 2017 or early 2018. In addition, as I stated earlier, NERC has revised BAL-002-2 to become effective on January 1, 2018, that could also impact the ability to buy and sell energy between the two utilities. Again, I recommend that Duke provide more detail about the effects of this new standard on the JDA in its rebuttal testimony. This expectation further supports the need for DEC and DEP to file their curtailment guidance documents with the Commission and for the Commission to determine the appropriate next steps to be taken.

Q: WHAT IS A PAF?

A: As described in greater detail in Public Staff witness Hinton's testimony, the PAF has been utilized in the past calculation of administratively determined avoided cost rates to account for the reality that no generator can operate 100% of the hours of the year, or even 100% of the on-peak hours of the year. The PAF allows a generator to experience a certain reasonable amount of outage time and still have the opportunity to receive a full payment for its capacity.

Q: WHAT PAF IS DUKE RECOMMENDING IN THIS PROCEEDING?

A: Duke witnesses Kendal C. Bowman and Glen A. Snider recommend a change in the PAF from 1.2 to 1.05 for all QF generation except hydroelectric. Witnesses Bowman and Snider state that their recommendation is reflective of the availability of a combustion turbine generating unit (CT). Witness Snider opines that because the peaker methodology is used to calculate avoided cost rates for DEC and DEP, it is appropriate that the rates paid to a QF are reflective of a peaker unit, in this case a CT. Because DEC's and DEP's CT fleets have a 95% starting reliability, witness Snider states that the PAF should be no greater than 1.05.

Q: DO YOU AGREE WITH DUKE'S PROPOSAL OF A 1.05 PAF FOR ALL QF GENERATION EXCEPT HYDROELECTRIC?

A: Not entirely. While I agree that a 1.2 PAF may no longer be appropriate for use in calculating avoided cost rates, I do not agree that the appropriate PAF is the one that matches the reliability of a CT. The peaker methodology uses a CT as a proxy for the pure capacity value of generation versus the energy value, but it is not meant to imply that all QF capacity calculations should be based on the characteristics of a CT.

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Q: WHAT PAF DO YOU RECOMMEND?

A: I recommend that the Commission approve a PAF value of 1.16, which is reflective of a broader plant availability factor (AF) average of 86.33%.

Q: HOW DID YOU DERIVE YOUR PAF AVERAGE OF 86.33%?

A: My calculation was based upon plant performance data filed by DEC, DEP, and DNCP in monthly Commission Baseload Power Plant Performance Reports (BLPPPRs), SNL[12] data, and responses to Public Staff data requests. When AF data was not available for particular units, I made assumptions based on historical performance of the unit using capacity factors (CF).[13] This calculation is similar to that made by the Public Staff in prior avoided cost proceedings. My calculation includes intermediate generating units in addition to baseload units, as well as some operating characteristics based on known information about certain generating facilities. This adjustment recognizes the changing characteristics of utility generation portfolios, with natural gas CC facilities running more like baseload units and coal facilities often running as intermediate units.

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[12] SNL is a service of S&P Global Market Intelligence, and is a paid, subscription service.

[13] For example, if the AF was not provided for a natural gas Combined Cycle (CC) generator but a CF was given, I estimated that the AF would be greater than the CF, as it is impossible for a plant to produce more energy (MWh) in a set time period than it is available to operate, if the plant's nameplate rating is reflective of its actual performance.

Table 1 below provides my calculation of the weighted six-year AF averages for DEC, DEP, and DNCP. After calculating the six-year weighted averages for each utility, I then utilized a simple average of the individual utility averages to arrive at an overall average of 86.33%. I provided this calculation, which results in a 1.16 PAF, to Public Staff witness John R. Hinton.

Table 1: Six Year (2011-2016) Average Availability and Capacity Factors

Six Year Average	DEC	DEP	DNCP
AF	88.24%	86.91%	83.85%
CF	81.56%	77.80%	74.96%

Q: WHY DO YOU PREFER YOUR METHODOLOGY FOR CALCULATING THE PAF TO THAT PROPOSED BY DEC AND DEP?

A: As I stated previously, the use of the peaker methodology for calculating avoided cost rates is a means of representing the "pure" capacity value of all generation, not just CTs. A CT is utilized because it is typically the smallest and least expensive increment of dependable, dispatchable capacity that a utility can install to meet load. Of course, a QF may operate many more hours in a given year than a typical CT would operate, so basing the PAF solely on the availability factor of a CT is not reflective of how it operates, or how a utility's own fleet of generating units operates. Therefore, as discussed further in witness Hinton's testimony, I recommend that the Commission consider this revised PAF calculation based on the

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historic weighted AFs of the utilities' baseload and intermediate generating units as a refinement and update to the Public Staff's previous PAF calculations.

Q: PLEASE DISCUSS DNCP'S PROPOSAL TO ELIMINATE THE LINE LOSS ADDER FROM ITS AVOIDED COST RATE SCHEDULES.

A: DNCP proposed to eliminate the 3% adjustment to its avoided energy rates for line losses due to the observed power flow issues on its distribution and transmission system resulting from the interconnection of distributed generation (DG). DNCP states in its initial statement, "[l]osses are generally only avoided when the substation load exceeds the local distributed generation on a substation bus."[14] Once power flows reverse direction and flow back onto the transmission grid, system line losses can theoretically increase. DNCP states that it has already observed these reverse (negative) power flows on at least 11 of 33 transformers in its North Carolina service territory, as well as neutral power flow (equivalent amounts of energy being generated by distributed resources and consumed by local load) on 18 out of the 33 transformers.[15]

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[14] DCNP Biennial Determination of Avoided Cost Rates for Electric Utility Purchases, pg 20 November 15, 2016.

[15] Ibid. Exhibit 7.

Q: HOW LONG HAS DNCP INCLUDED A LINE LOSS ADJUSTMENT IN ITS AVOIDED COST RATE SCHEDULES?

A: The line loss factor first appears in the DNCP's avoided cost rate schedules filed in Docket No. E-100, Sub 53 (1987 avoided cost proceeding). DNCP, known as North Carolina Power at that time, included language in its standard contract for QFs that recognized the benefit QFs provided to the system through the reduction of transmission losses (Section 5.2 of the 1987 standard contract). The rate was last increased from 2.7% to 3% in the 2008 avoided cost proceeding.[16]

Q: DOES THE PUBLIC STAFF AGREE WITH DNCP'S PROPOSAL TO ELIMINATE THE LINE LOSS ADDER?

A: Yes.

Q: PLEASE EXPLAIN WHY.

A: At a system level, DNCP has demonstrated that its North Carolina electric grid is experiencing reverse power flows onto its transmission system from DG. DNCP has shown that several of its substations are already experiencing reverse power flows, with some distribution substations impacted more than others. In the next few years as more DG is

[16] Docket No. E-100, Sub 117.

interconnected to the DNCP grid, those loss reductions will continue. It is no longer appropriate to include a line loss adder in the avoided cost rate schedules when line losses will continue to diminish as more DG is interconnected.

Q: DO DEC AND DEP INCLUDE LINE LOSS ADJUSTMENTS IN THEIR AVOIDED ENERGY RATES?

A: Yes. While DNCP makes the adjustment after calculating the avoided energy rates, DEC and DEP incorporate the calculation into their avoided energy rates.

Q: IS IT APPROPRIATE FOR DEC AND DEP TO INCLUDE A LOSS FACTOR IN THEIR RESPECTIVE AVOIDED ENERGY CALCULATIONS?

A: Neither DEC nor DEP have proposed to eliminate the loss factors from their calculations, and I do not recommend that they do so at this time; however, it may be appropriate for DEP to consider such an adjustment in future proceedings given the similar flow conditions as observed by DNCP on its grid.[17] However, it would be inappropriate to recommend DEP to make

[17] 183 out 340 (54%) distribution substations within DEP have DG connected. Public Staff Data Request, Q3-5, March 2017. See Public Staff Witness Metz Exhibit 2.

such an adjustment without a more thorough study of the issue. DEC has not yet observed the same power flow conditions from DG that DNCP and DEP have observed, and it would be inappropriate for DEC to eliminate the adjustment for line losses at this time.[18]

Q: SHOULD THE ISSUE OF LINE LOSS ABATEMENT IN THE DEC AND DEP SERVICE AREAS BE STUDIED?

A: Yes. Both DEC and DEP should continue to evaluate line loss abatement resulting from the interconnection of DG, and include their findings in the next avoided cost proceeding. If the interconnection of DG in DEC's or DEP's service areas are abating or eliminating line losses on the grid, then avoided energy rates should be adjusted accordingly. Therefore, I recommend that both DEC and DEP include a study in the next avoided cost proceeding of the impact of DG on line losses and report their findings including any appropriate adjustments to avoided energy rates.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

[18] 201 out of 741 (27%) distribution substations within DEC have DG connected. Public Staff Data Request, Q3-9, March 2017. See Public Staff Witness Metz Exhibit 3

Appendix A

Dustin R. Metz

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, 2008 and 2009 respectively. I graduated from Central Virginia Community College with Associates of Applied Science degrees in Electronics & Electrical Technology (Magma Cum Laude), 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management.

I have 12 plus years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical & electronic control system in industrial and commercial nuclear facilities, project planning & management, and general construction experience.

I joined the Public Staff in the fall of 2015 and have worked on utility rate case, fuel cases, applications for certificates of public convenience and necessity, customer complaints, nuclear decommissioning, power plant performance, and other aspects of utility regulation.

BY MR. JOSEY:

Q Mr. Metz, did you prepare a summary for your testimony, of your testimony?

A Yes, I did.

Q Would you please provide it at this time?

A Yes, I will.

(WHEREUPON, the summary of **DUSTIN R. METZ** is copied into the record.)

MR. JOSEY: Thank you. Mr. Chairman, the witnesses are available for cross examination.

CHAIRMAN FINLEY: Let's see if the Duke or Progress (sic) have any questions of these witnesses.

MR. BREITSCHWERDT: Yes, sir. Thank you. Good morning, Mr's. Hinton, Lucas and Metz. Brett Breitschwerdt on behalf of Duke Energy Progress and Duke Energy Carolinas.

CROSS EXAMINATION

BY MR. BREITSCHWERDT:

Q Mr. Hinton, I will start with you. So could you turn to page 5 of your testimony? I've just got some general, kind of background, questions about the Public Staff's investigation in this proceeding. Are you there?

A (MR. HINTON) Yes.

Q So on page 5 you generally identify trends and development of QFs in North Carolina and you discuss that in your summary as well; is that correct?

A Correct.

Q And on line 17 you start to discuss the, I guess we'll characterize that -- *a large percentage of those projects have been developed at or near the*

5-megawatt standard threshold. And then you go on to identify the number of projects in DEC/DEP installed 1600 megawatts and 4900 megawatts in the queue, and then turn the page to page 6, you identify that there are 2800 megawatts in Dominion's territory; is that correct?

A Yes.

Q And I'm sorry, just to be clear, there's 435 megawatts operation in Dominion and 2800 megawatts that are proposed?

A Correct.

Q And so my lawyer's math is that's 200 -- 2000 megawatts installed in North Carolina today and approximately 7000 that have been proposed solar QFs between Duke Progress and Dominion; would you agree with that?

A Subject to check, yes.

Q Thank you. And based upon your investigation in this proceeding, would the Public Staff agree that nearly 100 percent of QF development since the 2014 Sub 140 case has been utility scale solar?

A Yes, I believe so.

Q Did the Public Staff look outside of North

Carolina at trends in solar development over the past two years?
A Yes, I have.
Q Okay. And would you agree that across the country North Carolina has significantly more installed solar QFs than any other state in the nation?
A Say that once more, please. Are you referring to QF and we're number one in QF development?
Q Right.
A Can you restate the question?
Q Sure. So would you agree that North Carolina has significantly more solar QFs installed, so placed in service today than any other state in the nation?
A This and California has more -- I mean, I thought California had more solar megawatts but maybe QFs North Carolina, correct.
Q That's correct. Okay, thank you. And did you in your investigation look at PURPA implementation in other states in the southeast?
A Yes.
Q And we heard some discussion yesterday from Mr. Johnson on behalf of NCSEA about other states

and how to implement PURPA. And I had a discussion with Ms. Harkrader about Georgia and how PURPA is implemented in that state; is that -- do you recall that?

A Yes. I've had extensive conversations with the Georgia staff as well as representatives from The Georgia Power about how it works in that state.

MR. BREITSCHWERDT: Okay, thank you. Your Honor, I'd like to -- Mr. Chairman, introduce two cross examination exhibits at this time, if I could, please. Mr. Chairman, if I could mark these as DEC/DEP's Public Staff Panel --

CHAIRMAN FINLEY: Hold on just a minute. All right. What is your request?

MR. BREITSCHWERDT: To mark these as DEC/DEP Public Staff Panel Cross Examination Exhibits Number 1 and 2, please.

CHAIRMAN FINLEY: Well which is which?

MR. BREITSCHWERDT: The Public Staff Response to DEC/DEP Data Request No. 1 Data Request Question No. 6 is 1 and Question No. 5 is 2.

CHAIRMAN FINLEY: It shall be so marked.

MR. BREITSCHWERDT: Thank you.

DEC/DEP Public Staff Panel Cross Exhibits 1 and 2

(Identified)

BY MR. BREITSCHWERDT:

Q Mr. Hinton, have you had a chance to review these two exhibits?

A (MR. HINTON) Yes.

Q And so just to orient you this was a Data Request that you provided, correct? This is Exhibit Number 1 on behalf of the Public Staff.

A Yes.

Q And this reflects a communication with Jamie Barber at the Georgia Public Service Commission staff; is that correct?

A Yes, it is.

Q I'd like to first focus on that email and your discussion of how the QF rates are implemented in Georgia.

CHAIRMAN FINLEY: Mr. Breitschwerdt, let's hold on just a second until we get all of these exhibits passed out.

BY MR. BREITSCHWERDT:

Q And it's a little -- so I'm focusing on the back and forth in the email but specifically the email dated January 12th of this year at 11:20, where it's an email from you to Jamie Barber. And I

apologize, I don't know if it's Mr. or Ms. Barber. Which is it, Mr. or Ms. Barber?
A (MR. HINTON) Jamie is a female.
Q Okay, so Ms. Barber. And you're asking about PURPA implementation in Georgia and then it's a little confusing based on the way this was produced, but my understanding is that her responses to your questions, which are question 1 and 2, are identified in the email responses themselves; is that correct?
A Correct. We -- it's like the conversation continues to go but it is hard to discern who is speaking at certain points.
Q Okay. And I'm not going to have you read through this in detail but a couple of key points I want to make sure that it represented because there's been a lot of discussion about how PURPA is implemented in Georgia. Would you agree that small QF rates up to 100-kW, the energy component is fixed for only two years?
A Correct.
Q And after two years the avoided energy rates are refreshed?
A Correct, they are.

Q And for QFs in Georgia larger than 100-kW, they're paid an hourly avoided energy rate based on Georgia Power's what they call a System Lambda?

A That is correct.

Q And Georgia Power annually publishes updated avoided cost forecasts but the Georgia Public Service Commission in its implementation of PURPA doesn't mandate payments of fixed forecast energy rates further than two years into the future?

A Correct. They provide a forecast each year of avoided energy costs and avoided capacity costs. And, as discussed in my email, what -- one item that it touches on is it does provide QFs with an expectation of future avoided energy rates. Undoubtedly, this does help in their financing efforts. They can go to a lender and they can say even though we're guaranteed these energy rates for two years we believe the future will look like so according to the Company's projections, and that does provide some insight and comfort I believe. Again, I have not talked to a financier of renewable projects in the Georgia arena but I would expect it offered some guidance. It's obviously inferior to having fixed rates but it's something.

Q Thank you. And just moving on to the second question and answer where you were discussing with Ms. Barber, this was focused on the capacity aspect of the avoided cost rates in Georgia; is that correct?

A Yes.

Q And would you agree with me that, similar to Duke's proposal here and Dominion's proposal which the Public Staff agrees with in Georgia, QFs are not paid capacity until the first year that the Utility identifies a need in its IRP?

A Correct. If you'll look at the second cross examination exhibit, if you don't mind.

Q Please, we can turn there now.

A Where -- these are right off the internet for Georgia Power, and you see several -- it's data from an Excel spreadsheet obviously -- and you see several, three blocks of data. The block of data to the left is what I said before, it's kind of like an indicator block. In that column you see the avoided capacity costs column labeled KW per year and for this particular point in time the need for new capacity was established in 2024, at that time a capacity rate is given of $68.93, and then undoubtedly it's escalated for the next two years. Over on the right-hand block, the right-hand side of the paper you have two blocks, and it depends on I think when the QF signs on during that interim period, but you see there the rates and you see the components of the rates. You see the Lambda and then you see the Fuel Cost Multiplier, the Variable O&M Component, the Emissions Component and Start-up and those -- all of those items go into the -- into the energy rates, not just the Lambda. And I would argue that these rates here, these components here, are like we have here in North Carolina.

There was some discussion yesterday about FERC Order 714 in Glen Snider's testimony, and in his testimony the FERC only requires the Lambdas; the variable O&M data is not necessarily there; it does not include things like start-ups and O&M costs. Those are the components of energy costs. That's the difference between an avoided energy rate or cost and just a System Lambda. They are significant power points and that's the point that Georgia is alluding to its QF community that the rates that are published are based on these factors.

Q Thank you. And just so we're all clear, you pay capacity in the first year of need identifying the IRP. And then on the right side of this Exhibit 2, years 2016 and 2017, are the fixed avoided energy rates --

A Correct.

Q -- and then anything further out into the future is a forecast of for -- I guess if you look at footnote 5 it's for informational purposes, to your point that a QF can then go use for financing, but it's not a fixed long-term obligation on the utility and customers past year two; is that correct?

A Correct. My understanding is that the QF who signs in these years are entitled to capacity rates but only -- a capacity credit but only in 2024.

Q Right. And specific to the energy, it's an energy rate that's fixed for two years?

A Correct.

Q Which is similar to what Duke is proposing in

this case to mitigate the long-term forecast risk of energy commodity costs on customers; is that correct?
A I will agree that Georgia writes this as two years. And the other aspect of the value of two-year refreshing rates are what you said, yes, so yes.
Q Okay. Thank you. Let's talk a little bit more about the proposal that Duke has presented to reset its energy rate every two years as well as the, I guess what I characterize as the compromised proposal that Ms. Bowman and Mr. Snider presented in their rebuttal testimony. Are you familiar with what I'm referring to when I say the compromised proposal?
A Yes.
Q Okay. Thank you. And would you agree that this compromised proposal is intended to mitigate the significant forecast risk of over or under projecting long-term commodity costs?
A Yes, but I fear that the compromised offer, the person needs to understand the possibility that if the Company -- if the Commission orders the Company to use a -- its fundamental forecast then

those proposed energy rates in those years 2019 to 2026 will be raised. If you look at the details in these schedules which I can direct you to, you can see the components that go into the 10-year energy rate versus the two-year energy rate, the energy cost, the avoided energy cost that's a component of this proposal. Because if you accept the compromise then you forego the opportunity for the Commission to order and the Public Staff's recommendation to revise their natural gas price forecast to include fundamental prices not forward prices. The effect of forward prices you'll see in the avoided energy cost goes down in those years, they actually decrease. So the compromised proposal may provide security in knowing that you'll get that rate for the next 10 years but you also forget -- you're also foregoing the chance to get higher rates that in the Public Staff's opinion are appropriate in this proceeding.

Q Mr. Snider won't let me out of the room without talking extensively about fundamental forecasts and market rates so we'll get to that in a moment, but let's just focus in on the compromised proposal. So I think you agreed with me that the compromised proposal, the two-year or giving the QF the option to fix the two-year for 10 years will mitigate significant forecast risks of over or under-projecting long-term commodity costs; is that correct?

A It will do that, yes. I will --

Q Thank you.

A Okay.

Q And would you agree that that's a critical objective in light of the current levels of QF development in North Carolina today?

MR. DODGE: I'm going to object to this line of questioning. I think Mr. Hinton talked about, and you quoted from his testimony, the changes that are undergoing in the QF development and that this is one step of it that I think in regards to the two-year compromise, that was not something that was addressed in Mr. Hinton's testimony.

MR. BREITSCHWERDT: So does the Public Staff not have a position on --

CHAIRMAN FINLEY: Wait a minute. Now what's the -- this is unlimited cross. It is not limited to something that Mr. Hinton said in his testimony.

Overruled.
A Would you ask me the question once more?
BY MR. BREITSCHWERDT:
Q Sure. I just want to be clear. With 2000 megawatts of QF solar installed and 7000 megawatts -- I'll say 4900 megawatts proposed and looking ahead, would you agree that it's critical that we mitigate long-term forecast risks for customers through the avoided cost -- avoided energy rates that are established. And the compromised proposal that Duke has presented is that that's the objective of the way they've designed that compromised proposal.
A I do not know the real objective of that. As I've indicated, I think there's a real sacrifice involved if the other parties accept that compromise. But, as far as changing the forecast risk, it will provide certainty to the forecast that fuel -- avoided fuel energy costs for the 10-year period by fixing the two-year period. But I would argue that there are problems with that, you're not getting the benefits of what the future avoided costs will be. This proceeding is all about avoiding energy cost. I would argue

that --

CHAIRMAN FINLEY: Pull the microphone over, Mr. Hinton, so that we can hear what you're saying.

A I would tend to argue that the compromised position is a violation of PURPA in the sense that I don't believe those are the true avoided energy rates. The avoided energy rates are forward-looking, fixed -- forward-looking and, for our purposes, they're forward-looking over 10 years. And by just taking the two-year rate and just echoing it forward is not a forecast of the avoided energy costs.

Q I'm sorry to interrupt you. Were you finished?

A That's an --

Q Mr. Hinton, I would just say we are giving the QF the option to fix the two-year rate or take the two-year rate and take the potential upside benefit of avoided energy costs going up. If your fundamental forecast position is correct, then they should take that option and not fix the rate because, in theory, the avoided energy costs are going to deviate from past practice and be above what the Company says the avoided commodity costs are going to be. But if they want to fix that rate then they can do so but we're giving them that option. And I think my question is would you agree that if they have the option then that's something that they get the upside benefit or they get to accept the risk that the energy rate doesn't go up and that's their option to take? It's not something that the Company is forcing them to do but something the QF gets to elect.

A I accept your statement there. Again, but the offer is made before the Commission has had a chance to make a finding regarding the appropriateness of gas forwards or gas fundamental forecasts, thus, the parties would be accepting an offer that -- without full information to what they're giving up, if they accept your compromise.

Q Do you think the Georgia model is inconsistent with PURPA?

A It is inconsistent with how North Carolina has historically interpreted PURPA.

Q Is a two-year rate a fixed rate?

A The two-year rate is a fixed rate. There is an issue of discrimination in PURPA. And, as I've noted in my testimony - I'm certainly not a lawyer - but when the Utility plans and builds generation units it does not do so on a two-year premise except the Utilities have the obligation to serve where QFs have an obligation to fulfill their comment, I mean, contract, and I note that in my testimony. But it's not reasonable to think that a Utility would build a generating unit knowing that it would only get recovery for a two-year time period, on a fixed time period. There's an area of inappropriateness there. There's too much risk I think on the QF relative to the risk that Utilities have.

Q So, if the risk isn't placed on the QF and they're given the option to select the two-year rate and let it go up or down over the 10-year term or to fix the two-year rate, who is the risk placed on? Who takes that risk?

A I'm going to have to ask you -- I know that was a good question but could you say it one more time, please?

Q Sure. I mean, you said you're -- it's not appropriate to assign the risk to the QF of this rate changing in years three through 10, and that's not what the Company's proposal has done. It said you have the option of taking the benefit of the upside if you want to forecast out what the rate is going to be and if your fundamental forecast position is correct then energy rates are going to go up. However, if energy rates don't go up, they should take the two-year and fix it over 10 years, which they have the option to do. And in that case why would -- if the risk is not placed on the QF, who is it placed on? Who is the counterparty to the transaction?

A Well, ultimately the ratepayers bears --

Q Thank you.

A -- all these risks. I would to say that the heart of our concerns with the two-year rate largely go to financing issues. I don't believe, under my investigation with talking with bankers who specifically operate within the renewable space and developers, that a two-year financing is largely very difficult to accomplish. I remember in the last proceeding in Sub 140 Commissioner Bailey asked me a good, an excellent question that was about shifting from a 15-year term to a 10-year term. My response to him was that I'm often asked this question since I work in economics and finance but it's awful difficult to get this information. I said that my investigation with talking with people in this line of work was that the 10-year deal was quite doable. And I closed that conversation with but we're comfortable with 15. But -- and my testimony today is that a 10-year rate is doable, and I've talked to several people and they all say yes. They say it may require a little more equity. Some of the borderline QF projects will not be -- get financing, but a 10-year rate is quite doable. And that has been the guiding principle that I have used to make -- for my recommendation. So, when you talk about the risk of two-year rates that's what you were ultimately getting down to, the risk a QF cannot seek financing, and they all said that two-year refresh was not operable, was not doable. If other states offer two-year refresh, and like I've said the states in the southeast often do, I mean, like in Georgia and Florida and everyone but South Carolina, and you see two-year energy refresh, but you'll also see there's very little

QF development in those states. And the QF development you find is largely done by when the Legislature tells the Commission you shall get -- order this much QF development through your RFP process, whatever, it's not done because QFs come to the Utility and seek a certificate. They happen but not to any size.

Q Thank you. Just to -- so the specific answer to your question at the beginning was that if the risk is not placed on the QF of this forecast risk of what future energy commodity prices are going to be, it's placed on the ratepayers who ultimately pay the QF for the power during the term of the contract; is that --

A That's correct.

Q Would you agree with that?

A I will. And if you'll just allow me to expand on that just a moment. I believe as a ratepayer advocate the ratepayers pay for everything almost. This concept the stockholder bears all these risks, it's the ratepayer is how I kind of foresee a lot of it. The rate -- the forecast risk that we're dealing with, the overpayment of risk and underpayment of risk is largely what I consider a forecast risk. And as we're talking about when we project prices to be here and they come in here or when we check here and they actually come in here, there's under and overpayments, and my graphs of historical avoided energy rates bear that out. That same forecast risk that ratepayers bear from QFs, ratepayers bear from the Utility plant as well. We'd look -- in my testimony I mentioned Cliffside, the Cliffside Number 6 unit. I think that plant cost a couple of billion dollars. The rates are -- that people are paying for in their rates today. Now, it's being used as an intermediate plant. It was -- I worked on that CPCN and it was planned to be a baseload unit running with class factors in excess of 80 percent; it's not there --

Q Mr. Hinton -- I --

A So I'm just pointing out there are differences. And when you talk about forecast risk and risk of overpayment and underpayment, it just needs to be taken into context. And let me just say one last thing, for the Richmond unit that PEC built years ago, CP&L did, those were great choices. Sammy Waters from Florida came up and he persuaded management to go that route and they went it and I believe we have -- the ratepayers in North Carolina have benefited from it enormously because gas prices have been low and continued to look low and that's been a savings grace to North Carolina.

CHAIRMAN FINLEY: We're getting some awfully long questions and we're getting some awfully long answers and the time is fleeting so let's --

MR. BREITSCHWERDT: Yes --

CHAIRMAN FINLEY: -- be thy concise.

MR. BREITSCHWERDT: Yes, sir, I agree. I will try to make sure my answer -- my questions are concise and to the extent we can make the answers concise to those questions and move every one towards a noon departure date that will be most helpful.

BY MR. BREITSCHWERDT:

Q On page 30 of your testimony, line 22, if you could turn there please, I'd like to talk to you a little bit about the issues of the market, forward market data versus fundamental forecast, which has been a significant topic. You state that on line 22 that *fuel price forecasts are often the most influential factor on avoided*

energy costs and can cause significant changes between proceedings; is that correct?
A Yes.
Q And would you agree with me that no forecast will be completely accurate and is more likely to be inaccurate the further out into the future the forecast estimate is presented?
A Yes. Mr. Snider noted that with his cone conversation. That's very true. That same forecast error exists with forecast prices but forecast -- same forecast error occurs when you forecast with forwards, too. Forward prices can also, as indicated by our hedging losses, that the Company has exposed for many years.
Q So a 15-year term is riskier than a 10-year term and a 10-year term is riskier than a two-year term; correct?
A I will accept that forecast risks are greater the longer terms, yes.
Q Okay. Thank you. I would to talk with you a little bit about the Integrated Resource Planning process and the fuel forecasting that's been done. So there was some discussion with Mr. Snider about this yesterday. And you

identify on page 37 of your testimony --

CHAIRMAN FINLEY: The day before yesterday.

(Laughter)

MR. BREITSCHWERDT: We have been here awhile.

BY MR. BREITSCHWERDT:

Q You identify on page 37, line 3, that *it is important that the inputs used in the avoided costs model and the inputs used in the IRP model be consistent*; is that correct.

A Correct.

Q And would you agree with me that over the last five years Duke has evolved the way it's used market data, forward market data and fundamental forecast data in its IRPs? Let me give you a little more specific --

A I remember the 2015 IRP and the 2016 IRP, of course, I remember the 2014 IRP that used only five years of data, and the 2000 and the proceeding we have before us today that where 10 years of forward data is a basis for a forecast of natural gas prices.

Q So let me start back and move forward. So in 2012 -- well, if you don't agree or if you don't recall that that's fine. But in 2012, would you agree that the Company used two years of forward market prices followed by a transition to a fundamental forecast?

A That was the habit of Duke Energy Carolinas for many years and when they merged with Progress Energy Carolinas their forecasting team was changed. Glen Snider became head of forecasting and with him came a different emphasis on forward markets but, yes, they did evolve.

Q So an emphasis on forward markets. And did you hear Mr. Snider's testimony yesterday that a significant factor in the liquidity of the forward market was based on the changing natural gas markets?

A Say that one more time.

Q That over the past five years changes in the natural gas market have contributed to the increased liquidity in that market and that has been a driver of the use of the forward market data?

A I have to -- yes, I'll agree that liquidity is an important criteria for using forward prices and that's the heart of the Public Staff's concerns with Glen's -- with the testimony of the Company. We see there's a lot of activity in -- volume in the one to four years. And those as noted by -- they're in -- whether it's the ICE Exchange or the NYMEX Exchange, you see a very active trading. Mr. Snider talks about forward mar- -- forward prices into the context of doing bilateral transactions that he coordinates for the bank and pushes a button and gets a deal, and I'm not here to argue with that because I've never done those transactions. But my understanding of talking with people of ICE and other people in my research gives me the sense that that may be an accurate price but the confidence one has for that price may not be the same as what you have with a volume -- with the volume associated with an exchange trade.

And then the last thing I just want to say -- and I'm trying to shorten my answers because this is a big issue to me -- is that you can look at hedges, hedge trends, the hedge history of particularly DEP where the connection between hedging and forward prices are just that. When you make a hedge decision you're basically making a forward -- you're estimating a forward price because that's how you make the hedge. You think the price of gas will be here based on forward data and you lock in.

Q So --

A And Mr. Snider talked about swaps and that's exactly what the hedge material -- that's exactly the majority of all the hedge contracts that DEP has done in the last, since 2008 and 2009, have been with swaps. And I'm just here to say those swaps have errors, too. And that's my point about forecast actually, well not errors but they have risks.

Q That's it?

A Yes.

Q Thank you. So just before -- I'd like to talk with you a little about ICE and the NYMEX market, but if we could just step back. And I want to confirm that what the Company has done in terms of projecting forward market data 10 years out in the future as Mr. Snider said is consistent with its 2015 IRP. Would you agree with that?

A Yes.

Q Ten years of forward market data was used in the

2015 IRP?
A Yes. And the Public Staff did not do a complete review of that. I did examine -- I was the person that asked for the data request that you spoke of yesterday. I did a light review of it because it was in an update year and we were not expected to file comments and which we didn't.
Q And in the 2016 IRP again?
A Yes, and we used 10 years of data.
Q Thank you.
A Forward price data.
Q And do you recall back in the Sub 140 proceeding where Mr. Snider argued that there was sufficient liquidity to use forward market prices over 10 years and he identified that the Company had obtained transactable quotes from four separate market participants to demonstrate liquidity?
A Yes.
Q And he also stated at that point that that was the Company's intent going forward, to use this forward market data 10 years out in the future in future IRPs and --
MR. DODGE: Objection.
Q -- future planning?

MR. DODGE: Mr. Breitschwerdt, could you point the witness where that was included in the Sub 140?

BY MR. BREITSCHWERDT:

Q Perhaps if you could read that statement there. I think that's what I was just --

A *DEC and DEP further stated that they have used and will continue to use market pricing to the extent reliably available, and will use forecasted fuel information for periods when market data is not available or unreliable.* They added *the markets, not DEP and DEC, establish where the price transparency and liquidity exists determined by the simple market test -- market-based test of whether they are willing sellers and buyers and whether there is a reasonable spread between the bid and the ask price or action.*

Q Thank you. And so since that time the Company has used 10 years of forward market price data and has been consistent in the way that they have used that data in their subsequent avoided cost and IRP proceedings; correct?

A Correct. And I would just simply add that the

Public Staff's comments in the 2016 IRP also restated its objection to the use of 10 years of data while we are quite accepting to using forward markets for pricing -- for forecasting prices in the short term, and that's the logic and that's one reason that Duke Energy Carolinas uses that. When you do forecasting you often have to have a short-term model and a long-term model to create a forecast. The short-term models use forward price stats in the ideal arrangement. Long-term models depend on an econometric basis that looks at future supply and demand. And that's the reason why we -- that we're not supportive of the use of 10 years of data.

Q Thank you. I want to turn back to something that you spoke about a few questions back where you started going down the path of liquidity and ICE and NYMEX and over-the-counter markets. And so I think if you could confirm for me that you said you have spoken with people about the transaction that the Company did on April 5th, and that you would agree that the price is accurate but that the volume made -- or could you explain that to

me again?
A My point -- first, I did not speak to anybody about the transaction on April 5th.
Q Okay.
A Okay. All I'm saying is that as I look at the data, at your forecast and the position you're taking and I know that the NYMEX and the ICE markets, and I'm talking for those people at ICE in particular, and asked about the volume of trades and also suggested this and we had discussions -- this is all my understanding of these discussions by the way -- but there's a little less volume. I've also downloaded data off their website that illustrates the decrease in volumes as you go to year 1, year 2, year 3 and year 4. And by after year 4 there's very little volume of transactions from willing buyers and sellers of those future prices.
Q But that's on the ICE Exchange or the NYMEX Exchange; correct?
A Correct. And I've -- to go further, I am not talking to brokers with the large banks and credit -- and there's a whole lot of banks that Mr. Snider is familiar with, I have not done that

research with talking to those banks. I assume there's actually transactable data, and that's the key difference, there's transactable data but is it an exchange. It's like buying a car versus buying a stock on the U.S. -- on the New York Stock Exchange. When you buy a car you're not sure of what risk you're taking from -- especially if it's a used car, even a new car. But when you buy a stock on the stock exchange he knows there's thousands of people processing information, bids -- so you can feel that that car -- that stock really values its intrinsic value. And that's the key word - intrinsic value versus value. So you have more confidence in the intrinsic value of a stock market or an exchange-based futures price.

Q But -- and I appreciate that for long-term, 30-year projections at resource planning purposes. But what I think I understood you to say was that you've (1) not evaluated -- let me ask that question. You confirmed that you've not evaluated the over-the-counter market that Mr. Snider spoke to?

A I have not done a decent investigation of those markets.

(At the request of the Court Reporter, Mr. Hinton repeated his answer.)

A I have not done a thorough investigation or any investigation to speak of on that market of the futures market beyond what's available to exchanges, the secondary market that Witness Snider -- I mean, he has a background in trading and I don't.

Q So key point here - would you agree that for long-term planning purposes your concerns about the forward prices are different than if you are projecting out in the future what the forward price of power is going to be or what the forward commodity price of gas is going to be in making a commitment to a long-term Power Purchase Agreement?

A I hate to say that, could you ask me again, please?

Q Sure. So Mr. Snider's probably most fundamental point about this whole issue is that if you're talking about forecasting out in the future -- y'all can disagree over whether a fundamental forecast is appropriate or a market price is appropriate. But if you're talking about a 10-year purchase into the future, picking a fundamental forecast significantly above market in place of clear transactable data doesn't make sense because Duke can either buy gas or they can buy QF power and they should be interchangeable. They can go out in the marketplace and buy the gas to produce energy or they should -- or they can buy the QF power. Would you agree with that?

A I will agree with that. If you're limiting the discussion to someone sitting there and saying I've got to buy this QF power and all I can buy -- which I don't know what the price would be or I can lock in today on a future price 10 years from now, that's the way to go. I would lock in today because you've got certainty there. You've got supposedly a willing buyer who's willing to commit to that purchase.

Q And you heard Mr. Snider --

A But that's not what this proceeding is about nor is it about -- this proceeding is about setting up avoided energy cost rates and what is the best reasonable forecast for your future avoided energy costs, which are largely impacted by a future price of fuel prices. And I would like to say that on that level you do not find other utilities like TVA, like Southern or Georgia Power, like Florida, like South Carolina ENG, so all of these Utilities are, even in the southeast, do not use 10 years of forwards for planning, for setting up avoided energy costs, or for IRP. So I find that that's also a guiding principle why I think this use of 10-year forwards is inappropriate because other people do not use it for their IRPs. They use three years or four years or five years, and I've talked to those IRP people.

Q Mr. Hinton, specific to the question of avoided energy costs for this proceeding, your testimony is the market rate that the Company has established is accurate looking out in the future; is that correct?

A For -- I'll accept five years of data, forward price data is accurate.

Q And would you accept that the back five years based on the 10-year purchase that the Company completed on April 5th is representative of what

the forward market price is for a 10-year period?
A I'll represent that that was a deal that was made on April 5th, and I'm glad they were able to secure gas, but that's the same issues involved with hedging. I don't mean to belabor the point, but when Duke Energy Progress made hedge deals in 2008, they looked out forward in their crystal ball and they said gas is going to be high so we're going to hedge at $9 or $10. This is in one of my affidavits in E-2, Sub 10 -- 1001, 1018 and 1031, and I would suggest the Commission look at those affidavits and you'll see where I point out where these long-term hedge contracts, which are based on long-term expected forward prices, turned out costing the customers, ratepayers each year, the first time it was $49 million, the next year it was $50 million, the last time I did it it was $70 million for North -- not the system but for North Carolina --
Q Mr. Hinton --
A -- that's how much those hedge costs count which are based on forward price expectations.
CHAIRMAN FINLEY: I think we have belabored this point --

A Okay.

CHAIRMAN FINLEY: -- enough. I think we understand the differences between the Public Staff and the Company on this point. I think we got it. I don't think we're going to come to an agreement so if you've got another point let's move on, please.

MR. BREITSCHWERDT: Thank you. So I think that was all that I had for you, Mr. Hinton, on the publicly available part of the --

I do have a couple of confidential questions, Mr. Chairman, that I'd like to go into confidential session at the end, if that's okay. But I'd like to turn to Mr. Metz at this point and talk through the PAF.

BY MR. BREITSCHWERDT:

Q So I think your testimony covers both the system operations challenges the Company is facing and the Performance Adjustment Factor; is that correct?

A (MR. METZ) And the line loss adder; that is correct.

Q That's right. Thank you. And you are an engineer by training; is that correct?

A Correct.

Q And so from your perspective as an engineer, do you agree that there is the issues of assigning capacity performance adjustment multiplier for QF power and system operations issues that Duke Energy Progress is facing are interrelated?

A Can you restate that?

Q Sure. So would you agree that the -- let me go specifically to your page 4 of your testimony. Thank you. So you identify the challenges the Company is facing in responding to the BAL standards. And at the bottom of that page do you say that *the Balancing Authority must have firm contingency reserves and dependable capacity designated for deployment to meet disturbances*; is that correct?

A That is correct. On page 4 and continuation to page 5.

Q Thank you. And you then identify that variable and intermittent resources would not qualify as contingency reserve, rather they exacerbate the need for contingency reserves.

A That is correct. And tried to elaborate potentially more on an exacerbation on that, in regards to that. So as a variable or even an intermittent resource, the contribution changes at any given period. From an operational perspective, if a component changes you really cannot rely on that at a given period of time. And that's the -- wanting to add the exacerbation because if you're depending on a resource to be there at any given time and all of a sudden that resource is not there, whether it be on a one-minute interval because they're done by frequency response, 15-minute interval or a 30-minute interval, any time period, it would have dramatic impacts and those impacts would range over any given period of time given a magnitude of contingencies.

Q Thank you. And so I guess my key point and I'm trying to make a connection here between your testimony in the front half about system operations and the PAF. And would you say that the load-following generators that you talk about that are needed to manage frequency, to manage kind of the ramping issues that Mr. Holeman discusses, those are the same generators that you have taken into consideration when you've established the plant availability factor; that's the basis for your PAF proposal?

A Not necessarily on the same -- the PAF factor that I proposed did have a degree of switch activity as I -- I think that I pointed out in my testimony that I took baseload and intermediate generating resources. Some of the ramping characteristics Witness Holeman has stated would need -- I would consider peaking assets, which I specifically had removed from my PAF adjustment because the characteristics of a peaker plant are just generally different from standard operations of a fleet operation or, more specifically, a baseload or intermediate operation.

Q So did you take into account only units that had dispatchable, dependable capacity in establishing what the PAF proposal would be, intermediate baseload units; is that correct?

A I agree that the Utilities' assets are dispatchable and dependable.

Q Thank you. And would you agree that in contrast utility scale solar has no dependable capacity?

A From an operations planning perspective, if a -- as I stated earlier, if a source is intermittent it would be hard to provide a finite value on

what that capacity could be.
Q So to go back to my comment earlier about ramping and the need as Witness Holeman discussed to follow the Companies' load throughout the day and throughout peak periods, would you agree that solar doesn't -- QF solar doesn't provide the dispatchable, dependable capacity that is needed to meet that peak need during the day or during peak periods?
A Well, I believe as Witness Holeman has stated and is illustrated by his graphs and the curve in his figures, that you're talking about ramping periods when that is not peak times and that is low load periods. So just out of clarity are we talking about two different things here?
Q Well --
A You're talking about ramping and ramping is often the subset as demonstrated, that it's not during peak periods, it's just during typical operations of the day during low load periods.
Q Right. And I guess my point is that's based on the fact that you are rising to the daily peak during that day but I appreciate that -- essentially what I'm trying to tease out is that

solar, even in these off-peak periods is not there to meet the Companies' daily peak; is that correct?

A That is correct.

Q And so during the peak seasons would you also agree that solar is being paid at capacity value based on the Option B hours and it's being paid based on when the solar or QF delivers on peak?

A I'm not intimately familiar with Option A and Option B hours. I don't have that in front of me.

A (MR. LUCAS) I can answer that. Most solar QFs elect to go into the Option B because it's better payment for them because they're able to produce more energy during on-peak hours that better fits the Option B.

A (MR. METZ) And potentially to add onto that, I mean, it wouldn't make much sense for a solar generator then to enter into Option A just because it doesn't meet their generation profile. I remember when Witness Snider was discussing and he talked about the terms of availability or contribution to the system, I think there was interchange between Option A and Option B as to dealing specifically to a solar QF. Again, in terms of the standard offer in which a PAF is being applied it's non-discriminatory, it's based upon solar, non-solar, any QF.

Q But would you agree that there has been no -- non -- so I think Mr. Hinton said in the outset there's been very little, if any, non-solar QF development so it's been focused on this non-dependable capacity that we're paying a capacity payment to plus this PAF multiplier; is that correct?

A Can you please rephrase that?

Q So Mr. Hinton at the outset said since 2014, the amount of -- since Sub 140, the amount of development has been focused on solar. And so my point is that you're proposing a PAF multiplier for non-dependable capacity that is not available during your peaks, during the day, month or season. You can't dispatch it similar to the units that you're relying on in establishing the PAF; is that correct?

A Well, the PAF in itself does not directly detain from a dispatchability standpoint. I believe Witness Hinton had gone through extensively and through prior proceedings we talk about why the PAF is created. Would you like to elaborate on the --

A (MR. HINTON) I think all I would like to add is that is that one point that you made is that you were correct that most QFs have come of late have been solar QFs, but this rate is for the next two years. We're not saying rates for just solar. So I would add that it is appropriate to look at how this QF development, regardless of whether it's solar, or landfill gas, or the standard old boilers that the industrial customers used to have, that's the rates we're testifying to today.

MR. BREITSCHWERDT: And I just -- two exhibits, Mr. Chairman. Mr. Chairman, mark these as DEC/DEP Public Staff Panel Cross Exhibits 3 and 4.

CHAIRMAN FINLEY: The Solar Maximum Dependable Capacity is 3?

MR. BREITSCHWERDT: Yes, sir.

CHAIRMAN FINLEY: That will be so marked.

MR. BREITSCHWERDT: Thank you.

DEC/DEP Public Staff Panel Cross Exhibits 3 and 4 (Identified)

BY MR. BREITSCHWERDT:

Q Mr. Metz, so I think I'm trying to establish through -- let me ask you, does the Public Staff, between you and Mr. Lucas, review CPCN Applications that are filed with the Commission for solar QFs?

A (MR. METZ) That is correct.

Q And would you have reviewed the CPCN Applications filed last fall and approved by the Commission in October of 2016?

A It is very probable that I reviewed one of those.

Q Well, there's quite a few here so y'all worked very hard during that couple of months' span to get a significant number of these QFs to have LEOs established in the Sub 140 timeframe. And would you agree with me subject to check this represents the number of QFs that were approved for LEOs under Sub 140 with a -- during the month of October 2016?

A Subject to check, yes.

Q Yes. And would you agree that it's 625 megawatts of nameplate capacity, if you go down to the end there?

A Subject to check, yes.

Q Thank you. And if you could briefly turn to the Exhibit 4, this is -- you'll note that this is Slender Branch Solar, SP-81 -- 8116, Sub 0. Which if you briefly flip back to the last page of Exhibit 3 you'll notice Branch Solar 80 megawatts. And if you flip to the, I guess it would be the fifth page of Exhibit 3 that identifies the nameplate generating capacity of 80 megawatts.

A So where are we going with this?

Q Exhibit 3?

A Exhibit 3?

Q Exhibit 3 of the CPCN Application.

A The box highlighted in red?

Q That's correct.

A Okay. Thank you.

Q So it would be the nameplate capacity of 80 megawatts. And then the second box identifies the QF, identifying it has 0 megawatts of dependable -- so *given that solar energy is an intermittent resource, the dependable capacity of the facility is 0*. Do you read that there?

A That is correct.

Q And so if you go back to Exhibit 1, the maximum dependable capacity of all of these solar QFs. If you look through the CPCN Applications, would you accept subject to check that they all have similar characteristics and are not able to deliver dependable capacity similar to this 80-megawatt generator?

A I would agree and also state typical for -- or solar QFs do not provide a dependable capacity. But I also would like to go on and say that a dependable capacity does not reflect the amount of potential capacity contribution that it gives to the system or may provide to the system. We're interchanging operations and operations terminology of the dependability in system planning with the PAF factor.

Q But wouldn't you agree that capacity whether it's, to your point, that it's needed on peak, it's needed when the system needs capacity?

A Capacity is needed regardless of peak in terms of daily operations. I'm not going to go as far as Witness Holeman when he needs capacity and energy, but capacity is needed throughout the day.

Q And it's focused on capacity being paid in peak

periods to QFs under the PAF; is that correct?
A Yes.
Q And so we're focused on -- I think you've agreed that these CPCN Applications represent that these QFs have -- solar QFs have no dependable capacity and that they wouldn't deliver capacity during the peak periods?
A I wouldn't say they would not deliver because if they're operationing then they are delivering a portion. I mean, as I stated earlier, it is intermittent or variable in nature so it is harder from a system planner. And I think my testimony has gone through very clearly and stated that it is hard from an operations perspective to plan for intermittent or variable generation but, however, there is a subset of capacity that is provided to the system.
Q And would you agree with me that for purposes of the PAF, the time that the PAF is focused on -- the Performance Adjustment Factor is focused on performance during the peak period?
A During the hours at which they agree on. I don't remember the exact hours during Option B.
Q Right. But when you ran your analysis of how the

PAF should be calculated and you said there was some subjectivity in it, you didn't look at the peak periods when capacity was needed, you looked at the entire year; is that correct?

A I looked at it in an annual period, correct, and I did not segregate against day versus night.

A (MR. HINTON) The only perspective I'll add, and I'll be brief, is that the PAF is still bound on his analysis on the Utilities' operation, not necessarily the QF's operation. Now, the PAF does go into an equity issue which we can discuss later but I just want to focus -- Witness Metz was examining the baseload operations and intermediate operations and peaking operations of the utility systems. That's all I would add.

Q And so your focus is on the availability. So Duke and the Public Staff agree that the availability factor is the appropriate factor to use when establishing the PAF; is that correct?

A (MR. METZ) I believe the Public Staff has made a significant change in how we evaluate it. In prior proceedings I believe it was discussed as a capacity factor as Witness Hinton went through and provided some of the history of how this has evolved. I believe the Commission made their Order in Sub 140 that hey you need to, just paraphrasing, or you need to maybe look at how this is happening in a different perspective and capacity factor may not be relevant. Based upon that input I looked at availability and it was subjectivity into what units were selected due to the general characteristics. But again it was based upon looking at the availability, not segregating or discriminating against, in an exact case Option A or Option B, or looking at a QF-specific technology. It was made to be applied to any QF that could have different operation characteristics, some of them may be a baseload and run at nighttime during off-peak hours as Option B as I've stated.

Q Okay. But specific to solar QFs, would you agree that the PAF is compensating them based on their availability to deliver during the peak periods? That's when the hours are established. They're paid for capacity during the peak periods.

A They are paid for capacity during the peak periods; that is my understanding.

Q And the Companies' proposal in Mr. Snider's testimony was that the equivalent forced outage rate was an appropriate metric to focus on the capacity delivered by these dispatchable load-following intermediate and baseload units during peak periods. Do you agree with that?

A Will you rephrase that, please?

Q Did you review Mr. Snider's testimony on PAF, his rebuttal testimony?

A I reviewed his rebuttal testimony on the PAF and tieing that back in the EFOR. His original testimony mentioned the reliability CT as a metric to do the PAF. I believe that was the same stance that the Utilities have taken, or Duke has taken in the past. And as the Commission has stated before and authorities have stated that maybe that wasn't just right and maybe we need to look at a different perspective. Witness Snider filed in rebuttal the EFOR. I have not had time to review the maybe potential underpinnings of how he derived the EFOR but I have a basic understanding of the EFOR rate. And on that is when I initially looked at the availability factor I actually considered utilization of the EFOR factor, but the EFOR factor I thought had potential challenges, I wouldn't go to say flaws. I mean, as Mr. Snider stated there's many ways to debate a PAF factor. It's just which one is particularly a correct metric to look at capacity contribution.

Some of the underpinnings on why I did not use the EFOR, it got into maintainability and reliability. Availability from a statistical standpoint is both the metric of applying reliability which is a failure, time between failures, and in order to minimize the time between failures, you have to look at maintainability. Both of those components apply into availability. High availability does not mean high reliability. They can be exactly opposites. You can have something that has a relatively low reliability as in failure but it can be offline because you have to perform an abundance amount of maintainability in order for it to work. Other components going into that is looking at maintenance, maintenance and refueling. So if we take nuclear, for example, nuclear refueling, well the typical refueling activity, to generalize, is approximately 20 days. But, however, outages they will range depending on the maintainability that is needed to keep the reliability failure time at a low level. And that will be changed -- that can change any given time as through their preventive maintenance procedures of what is identified. Those were some of the underlying conditions of why I did not consider utilization in the EFOR.

Q So you would say that you've not had a chance to review Mr. Snider's rebuttal analysis in detail; is that correct?

A There was no -- I'm not aware of any workpapers being provided to support that value. At face value, I agree approximately 5 percent is probably a good metric with removal, as he stated, of maintenance. But as I tried to iterate that maintenance is a key factor into how reliable or how often a plant could or could not fail.

Q But would you agree with Mr. Snider's testimony that that maintenance is done in off-peak periods, and so that, if you're focusing on the capacity period where -- the period where capacity is needed which is at the peak, then that would not be the time that a nuclear generator would be out for 20 days?

A Well, again, his iteration or focus point was -- where I have a disagreement, a respectful disagreement -- was he looks at it from low peak as in system peak. However, QF generators provide a capacity during those refueling or maintenance periods. There is contribution of capacity from QFs, regardless of technology type during those periods of time which he removed from his analysis, which is what I understand from his rebuttal.

Q So he focused on peak which is an apples-to-apples comparison to when QFs are paid for capacity. And your position is that's not appropriate because the QF provides some capacity value in off-peak periods?

A No, I think I've said quite that the -- portions of that -- the opposite of that again. That if -- let's just take a theoretical example, and you say the month of March I needed to bring down a unit, it doesn't matter - nuclear, coal, gas, it doesn't matter - you've got to bring it down for maintenance, okay. Well, that wouldn't be reflected in an EFOR because it did not fail. But that whole month of March in this theoretical example the QF provided contribution to capacity. Removal of key points from a system-level peak is not an apples-to-apples comparison.

Q And I think at the beginning of the discussion I was trying to establish, based on the system operations, that during those off-peak periods when the Utility actually needs that capacity is not when a solar QF is available. Would you agree with that?

A As I've stated before and before, peak occurs on every day.

Q Correct. And would you agree that in these off-peak months, the non-summer periods, the non kind of the non-Option B hours when it's the non-summer periods, the peak occurs not during the periods that the QF is -- the solar QF is delivering energy to the Utility? This is the point that Mr. Holeman was making the other day that it's not available at 7:00 a.m. and it's not available at 4:00 p.m. when the Utilities needs are ramping up; is that correct?

A From a systems operation perspective, again we're jumping back and forth between systems operation and the PAF factor, which they are somewhat separate. I understand they are tied but, again, they're two different functions.

Q And I appreciate that. I guess I -- and this is why I asked you as an engineer if there was a correlation that was trying to bring the fact that we're paying solar QFs almost exclusively for capacity as well as a multiplier for performance even though they're not available at the time of peak, and that in doing so is that an appropriate --

A Well to back up to say --

Q -- multiplier?

A -- the PAF proposed is for a standard contract non-discriminatory, again, non-discriminatory to a generation-specific plant.

MR. BREITSCHWERDT: Well, I'd like to introduce one final exhibit on this area please if I could, Mr. Chairman? This should be DEC/DEP Exhibit 5, Public Staff Cross Exhibit 5.

BY MR. BREITSCHWERDT:

Q And so thank you, Mr. Metz, for your discussion of PAF. I'd like to take it back to Mr. Hinton for a brief discussion --

CHAIRMAN FINLEY: Hold on a minute. Hold on. The exhibit passed out is being marked for identification as DEC/DEP Public Staff Cross Examination Exhibit Number 5.

DEC/DEP Public Staff Cross Examination Exhibit 5
(Identified)

BY MR. BREITSCHWERDT:

Q So, Mr. Hinton, still on the topic of PAF and the availability of --

MS. MITCHELL: Mr. Chairman, I'm going to make an objection here. I understood Duke to be finished with their cross examination of Witness Hinton.

MR. BREITSCHWERDT: I certainly didn't say that. I said I had questions for Mr. Metz on PAF data. They both addressed the PAF issue, but I'll be quick.

CHAIRMAN FINLEY: Overruled. Overruled.

BY MR. BREITSCHWERDT:

Q So, Mr. Hinton, are you familiar with this data response?

A (MR. HINTON) Yes.

Q Are you familiar with the email that was attached

produced by the Public Staff?
A Yes.
Q Thank you. And specific to the issues that we were discussing about PAF availability and peak versus not on peak, could you share with the Commission who Ms. Nieto is?
A Yes. Amparo Nieto or Nieto, she works for NERA. And, as you may recall, NERA, National Economic Research Associates, they developed the grey books and they are the founding organization behind the peaker methodology that we use here in North Carolina. So I had taken a course on marginal cost ratemaking under NERA several years -- two or three years ago, two years ago, and so I had a working relationship with her.
Q Thank you. And would you -- is it fair to say that she is an expert on the peaker methodology and the value of capacity based on the peaker methodology?
A Yes.
Q And the -- in the email -- if I could just characterize it and please let me know if you disagree. You had sent her an email on March 20th identifying this proceeding and your

ongoing investigation of the Companies' avoided cost rates and Ms. Nieto responded in the email on March 21st dated, and at 1:40 a.m. She was up early. But she identified in the second sentence where you were asking about the value of intermittent renewables, solar, and she identified when that her view, based on her expert judgment applying the peaker methodology, is that these are not considered firm resources, and so they have generally little capacity value. Did I read that highlighted first sentence correctly?

A You did but I feel that it's my obligation to give a little deeper context of the interaction between Ms. Nieto and myself. She also filed an affidavit in the EPCOR case where she had testified in her affidavit that Carolina Power & Light at that time was not in a situation where they had excess energy, excuse me, excess capacity and that she saw no reason why you would have that unless you had a situation -- no use to -- there was no reason to give zero capacity value unless you were in a situation of severe deviation from optimality, which is addressed in my testimony. So that's the nature of the conversation. So in her other works that she had done she had came to the conclusion that solar and wind, in her particular testifying cases, had little capacity value.

In North Carolina, our history of looking at PURPA and the capacity value of intermittent resources, as illustrated in Sub 140, was that there's a diversity in the system and that there may be obvious -- the sun may not be shining in eastern North Carolina but it is shining somewhere in the State of North Carolina that's under Duke's control, and there is capacity value you can reasonably expect all of the time. And it's that assumption that somewhat underpins the differences between our recommendations in this proceeding and the -- with Mr. Metz testimony there which I agree with, about in a short-term nature there is less planning ability, but in the IRPs there is capacity value associated with solar resources. They are in the current IRPs and have been for years.

Q And, Mr. Hinton, Duke hasn't taken the position that there is zero capacity value for this standard offer in this proceeding for solar or non-solar; is that correct?

A That is correct. But I just wanted to make sure that these sentences that you've highlighted were looked upon in that --

Q Fair enough. But I really want to focus on the second sentence that I've highlighted later in her email to you and if there's something that we need to identify, but it says a *key factor here is to what extent the existing and upcoming wind and solar generation can be considered a capacity resource that actually generates at peak and reduces system on-peak capacity needs*. Did I read that correctly?

A You did.

Q And so if we are evaluating the capacity value on peak and at the system peak to offset other capacity needs, would you agree with me that it's appropriate to establish a Performance Adjustment Factor, a multiplier, that's also focused on on-peak periods of the Utilities' availability, the Utilities' generation availability?

A Right. The -- I -- yes, yes, I agree.

Q So we're focused on peak and so --
A Right.
Q -- apples-to-apples comparison is the Utilities' generation on peak is the appropriate metric?
A Well --

CHAIRMAN FINLEY: You should have stopped when you were ahead there, Mr. Breitschwerdt.

(Laughter)

MR. BREITSCHWERDT: Thank you.

A (MR. HINTON) For setting avoided cost rates in the PAF, we look at the whole system. For the designing -- for the rate design aspect of avoided capacity rates, we do look at the hours and we set avoided cost rates based on paid on a kWh basis. So under that context we look at a whole collection of hours not just a single one-hour peak.
Q I think I'll move on. Mr. Lucas, if we could take one step back I've just got a couple of questions for you. Exhibit 3 that I passed out which was the Cypress Creek CPCN Application, do you have that?
A I'm getting it.
Q Oh, excuse me, I apologize, that was Exhibit 4.

A I've got it. I've got the exhibits.
Q Thank you. So I just -- I understand the Public Staff's position and you did a very nice job of going through it in your summary at the beginning of what a legally enforceable obligation is based on your proposal, but I just want to run through a hypothetical to make sure I understand how this would work in the real world. So this generator, 80 megawatts we talked about earlier, submitted a CPCN Application on July 22, 2016; would you agree with that? I'm just -- based on the date on the --
A Yes, yes.
Q And so, if we assume that they submitted an interconnection request on that same date, then 95 days -- and assume they're a Project A, 95 days into the future is that's your proposed standard; is that correct, that 95 days into the future they would be able to establish a legally enforceable obligation; is that correct?
A I'll just lay out the steps. It would have -- to establish the legally enforceable obligation this particular facility would have had to receive its Certificate of Public Convenience, it would have

had to submit an interconnection request, it must be a Project A or B in the interconnection queue, and either 105 days would have passed from submitting the interconnection request or the facility would have received the results of its System Impact Study.

Q Thank you. And, I'm sorry, I misspoke when I said 95 days, 105 days. So let's assume that they are -- Cypress Creek is building this project, they've done the Form 556 which takes one day, there's no approvals, they submitted the CPCN Application to the Commission, which I discussed with Mr. Metz a little bit earlier was approved in October of 2016, and then 105 days from July 22nd, just roughly let's say that's mid-November of 2016; would you agree with that or subject to check --

A Yes.

Q -- agree with that?

A Yes.

Q So that's the point in time where they could establish their LEO?

MR. DODGE: Objection. I'd like to object. I think Mr. Lucas indicated they also had to submit an interconnection request and be a Project A or B not just --

BY MR. BREITSCHWERDT:

Q And I -- if that's not clear, let's say they've done all of those things. They submitted their interconnection request on July 22nd, the same day they submitted their CPCNs. I'm just trying to line this up and make this a real world project development example. Would you agree that they submitted the interconnection request early in the process of developing a solar QF?

A (MR. LUCAS) Yes.

Q Similar to when they submit their CPCN Application early in the development process?

A Yes, they can do that.

Q Okay. Thank you. And so if we're -- under the Public Staff's proposal, it's 105 days if they're a Project A, which for the purposes of this hypothetical they would be, that they would get to the point where they would establish a legally enforceable obligation. Would you agree with that?

A Yes.

Q Okay. Thank you. If you could turn to -- and I just want to kind of focus in on what we're talking about in terms of commitment here. So the Utility is committing, if you move to Exhibit 3 where we talked about earlier, that this is an 80-megawatt generator --

MR. BREITSCHWERDT: Excuse me, for clarification in the record, in DEC/DEP Public Staff Cross Exhibit Number 4 there are exhibits identified throughout.

BY MR. BREITSCHWERDT:

Q And Exhibit 3 to the CPCN Application identifies this as an 80-megawatt generator and that the -- and I'm down on point nine, there's 178,000,000 kilowatt hours or 178,660 megawatt hours a year of production from this generator; do you see that?

A Yes.

Q So if you could -- would you agree with me that through establishing a legally enforceable obligation, the QF is committing the Utility that they have to purchase that amount of power at some point in the future at the avoided cost established at that time?

A With one provision is if the QF actually builds the facility.

Q Excellent. That's exactly where I wanted this to go. So if you could move to Exhibit 5, and so this is the projected cost of the facility, $157 million for an 80-megawatt generator. And so would you agree with me that the long-term obligation that the Companies would be committing to would likely be in excess of $157 million because that's the QF --

MR. DODGE: I'd like to object here. Mr. Lucas is an engineer and he's not --

CHAIRMAN FINLEY: Let him -- let him finish the question, please.

A Can you start the question again, please?

BY MR. BREITSCHWERDT:

Q Sure. So I guess I'm trying to establish the point that we heard from Mr. McConnell yesterday that they're in the business of building solar generators and you earn -- you recover your investment and then you earn a return on your investment. And so, if they're going to enter a PPA to build this generator, they have to recover this amount of money; is that correct?

A Yes, they have to recover their cost.

Q Okay. And so that's part of the obligation that the Utility has committed to at the point in the LEO is --
A No. There are a lot of tax credits, there could be RECs, there are a lot of other financial instruments that go into paying for that cost.
Q Okay. That's fair enough. But to your point earlier, they've committed to the amount of hours that they would buy at whatever that avoided cost is if the generator is built?
A Yes.
Q Okay. And so we established earlier that they completed the commitments to establish a LEO by November of 2016; is that correct?
A That's possible. They could have done that.
Q In this hypothetical scenario?
A Yes.
Q And if they don't -- so if the project -- if the interconnection process takes longer than four months so it moves to the System Impact Study and it takes 12 to 18 months for a generator to get to an Interconnection Agreement, would you agree with me that there will be a period of time where the QF doesn't know whether or not it's going to

build the project or not and whether it's actually going to deliver these kilowatt hours to the Utility?

A That's up to the individual QF developer as to when they want to commit to build the project to its financial providers. It could wait until after the System Impact Study results to decide to build the facility.

Q But the Utility is committed but the QF is not to build -- the Utility is committed to buy but the QF is not committed to deliver the energy until they make that determination that they want to enter into a PPA; is that correct?

A That's correct.

Q And so the Public Staff's proposal is that even if a QF doesn't know if it will be viable to build a generator, even if it's not economically technically feasible based on the upgrades or whatever other costs or factors that the QF ultimately decides whether or not to build, the Utility is obligated for this amount of megawatt hours from an 80-megawatt generator over the term of the PPA; is that correct?

A That's correct.

Q And so the QF can make this legally enforceable commitment to sell without committing to build a generator at all?

A Yes.

Q And do you know any other state in the country where a QF can make that sort of nonbinding, nonmeaningful commitment and get avoided cost rates during a legally enforceable obligation?

MR. DODGE: Chairman Finley, I'd like to object to that question. Mr. Lucas is testifying on behalf of what the LEO process should be here in North Carolina and not necessarily conducting a survey of what other states around the country have utilized.

BY MR. BREITSCHWERDT:

Q Mr. Lucas --

CHAIRMAN FINLEY: We've had a whole lot of testimony about what happens in other states in determining how to apply PURPA. Overruled.

A (MR. LUCAS) You use the word "nonmeaningful" and that's hard to define. And these things in absolute periods of time, as the QF moves through the interconnection process it receives more and more information as it moves along. So to say at one point it has -- it can't make any meaningful commitment, there's just no one point where that can be determined.

BY MR. BREITSCHWERDT:

Q If a QF wants to make a meaningful commitment to deliver power to the Utility, wouldn't they do that through executing a Power Purchase Agreement and committing to do so?

A Yes.

Q Okay.

A I believe you were talking about the interconnection process.

MR. BREITSCHWERDT: I don't think I have any further questions. Thank you. And, Mr. Chairman, I do have a couple of confidential questions for Mr. Hinton that I'd preserve.

CHAIRMAN FINLEY: How long is that going to take?

MR. BREITSCHWERDT: Five minutes.

CHAIRMAN FINLEY: I'll tell you what, we will stay around to hear the confidential questions of Mr. Hinton and everybody else can take a break and come back at quarter until twelve. So if you're not -- if you haven't signed a confidentiality agreement you're welcome to leave the hearing room and come back at quarter til twelve, and we will go into a confidential session at this time.

Madam Clerk, if you will indicate in the transcript that the testimony from this point until I tell you otherwise will be marked confidential.

(WHEREUPON, Confidential testimony begins and shall be filed under seal.)

MR. BREITSCHWERDT: [redacted]

[redacted]

BY MR. BREITSCHWERDT:

Q [redacted]

CHAIRMAN FINLEY: [redacted]

MS. FENTRESS: [redacted]

MR. BREITSCHWERDT: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. BREITSCHWERDT: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. BREITSCHWERDT: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. BREITSCHWERDT: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. BREITSCHWERDT: [redacted]

BY MR. BREITSCHWERDT:

Q [redacted]

[redacted]

A [redacted]

Q [redacted]

A [redacted]

[redacted]

Q [redacted]

A [redacted]

Q [redacted]

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Q [redacted]

CHAIRMAN FINLEY: [redacted]

[redacted]

BY MR. BREITSCHWERDT:

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

[redacted]

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

MR. BREITSCHWERDT: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. DODGE: [redacted]

[redacted]

BY MR. DODGE:

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

A [redacted]

Q [redacted]

[redacted]

A [redacted]

MR. DODGE: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. SOMERS: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. SOMERS: [redacted]

CHAIRMAN FINLEY: [redacted]

MR. SOMERS: [redacted]

CHAIRMAN FINLEY: [redacted]

[redacted]

(WHEREUPON, the Confidential portion of the transcript has concluded.)

CHAIRMAN FINLEY: And we will take a break, and the Commissioners can take as long of a break as they want.

(Laughter)

I'll be here at quarter til twelve to tell everybody else when we'll start back. Let's take a break.

(Recess at 11:41 a.m., until 11:50 a.m.)

CHAIRMAN FINLEY: Dominion, you have no cross?

MS. KELLS: No, sir, we don't.

CHAIRMAN FINLEY: Intervenors.

CROSS EXAMINATION

BY MS. MITCHELL:

Q Mr. Hinton, Charlotte Mitchell, NCSEA, how are you?

A (MR. HINTON) I'm doing fine.

Q Just a few questions for you. Mr. Hinton, in your testimony you state that the avoided cost determined by the Commission in this proceeding will have implications beyond the rates that are paid to QFs; is that correct?

A I said the -- when you say implications beyond QFs could -- I'm not sure I said just that. Could you ask me again, please?

Q Well, I believe that you testified that the avoided cost determinations made by the Commission impact other utility programs such as the DSM/EE program.

A Yes, they do. There's avoided cost calculations within DSM/EE programs and the decisions we make here could very well impact future avoided cost rates for these programs. And they also set the dividing mark between -- for REPS when a company comes in to get rate recovery for its cost of renewable energy a portion of it will go to fuel and a portion will go to the REPS Rider cases.

Q Okay, thank you. Turning now to the Utilities' proposals related to the calculation of avoided capacity costs. I understand your position to be that the Public Staff's position in this case is to support Duke's proposal to limit capacity payments to those years in which the IRP shows a capacity need; is that correct?

A Yes.
Q And isn't it true, Mr. Hinton, that the Utilities make capacity additions or seek to make capacity additions that are not indicated in the IRP?
A It is -- it can happen. I would -- if -- this is a new thought pattern for planning which does give the IRP a little more importance so I would hope that that will not occur in the future. But, yes, if -- it has happened in the past and I would -- I would -- there's one issue that could address this, if you don't mind. In Georgia and other states they'll look at the IRP and they give the IRP a lot of weight. They'll say at this state in 2021 or 2022, they'll say there's a formal statement of need. Well, that declaration carries weight in the avoided cost proceedings, regardless of what happens in the next six months so that statement of need becomes an important recognition.
Q Understood. And, Mr. Hinton, have you reviewed Mr. Petrie's testimony regarding the shift in Dominion's next capacity need from 2022 to 2024 to 2026?
A Yes.

Q So is it a fair characterization to say that Dominion's need appears to be shifting as well and that would be reflected in its IRPs?
A As I -- first, I didn't have a chance to review the background of that statement by Mr. Petrie. It almost appeared like he said the load forecast changed thus the need changed. Without necessarily going through the complete capacity expansion model, as you are well aware there's just a lot of factors that go in an IRP than just a load forecast and a reserve margin calculation, so I can't accept Mr. Petrie's petition to extend the need out further.
Q Understood. Mr. Hinton, I don't understand you to be saying in this proceeding that a short-term resource adequacy reduces the cost of future capacity additions. Am I correct in that understanding?
A I think you are. You started off with a double negative and that's always confusing for the simple mind I've got but I think I agree with you.
Q Understood. But you're simply recommending that the Commission accept Duke's proposal at this

time; isn't that correct?
A For avoided capacity rates, correct.
Q Understood. Thank you for that clarification. And isn't it true that both DEC and DEP have long-term capacity needs or --
A Yes, they do.
Q And isn't it true, Mr. Hinton, that the IRP, the biennial IRPs to be clear, may not be approved at the point in time in which the Utility makes its avoided cost initial filings given the timing of the two dockets?
A That's currently the situation we're in. I have -- I was pleased when years ago, and I made this petition as an individual that the March date worked better for the year -- for that one year awhile back. That would give sufficient time for at least a preliminary review of the IRP and maybe even a potential Order issued by the Commission recognizing a statement of need that would be able -- then being used in the avoided cost proceeding. So given a little more separation other than 60 days would be warranted if we moved to this position of setting capacity on the next need in the IRP.

Q Okay. Mr. Hinton, in your testimony you indicate that the Public Staff supports the Utilities' proposal to reduce the maximum contract term offered under the standard PPA to 10 years; is that correct?

A Yes.

Q And the Public Staff's position is based, at least in part, on its review of PPAs negotiated recently with the Utilities; is that correct?

A Yes.

Q And you testified that both Dominion and the Dukes have entered into 10-year PPAs with QFs; is that correct?

A Correct.

Q And did your investigation reveal that these PPAs were with solar QFs?

A I did not go into that detail. I just understood that these PPAs were done on 10-year deals and that was the limit of my investigation.

Q So it was possible that these PPAs were with solar QFs and not other types of QFs?

A Correct.

Q Okay. And so you didn't examine whether these solar -- whether the QFs that were the subject of these PPAs were -- you didn't examine the size of these capacity -- of these QFs from a capacity standpoint?

A No, I did not.

Q Were you in the room yesterday during the testimonies of Mr. McConnell and Ms. Harkrader?

A Yes.

Q And did you hear them testify about the difficulties in obtaining financing for small QFs that would be posed by the reduction in term to 10 years?

A I did.

Q And do you agree, Mr. Hinton, that a reduction in PPA term coupled with the modification to the avoided capacity costs that Duke proposes would have an additive effect in terms of enabling -- challenging the QF's ability to obtain financing?

A Yes, I will agree to that. And that basically in part with my discussion with Commissioner Bailey in 140 that if we went to the 10-year term I expected maybe some QFs who could not obtain financing which would equate to they would have to have more equity or capital beforehand.

Q Understood. One last question for you, Mr. Hinton. Were you involved in the preparation of the Public Staff's comments in the 2016 IRP proceeding --

A Yes.

Q -- that were filed on February 17, 2017?

A Yes, I was.

Q I'm going to ask you one question about those comments. On page 23 and 24, the following sentence occurs, and I'll read that sentence to you just to refresh your recollection.

MR. DODGE: Do you have a copy of those comments with you?

MS. MITCHELL: I do have a copy of those comments.

A Yes.

BY MS. MITCHELL:

Q Mr. Hinton, again on page 23 and 24, and I believe it's highlighted on the version of the comments that you're reviewing, the following sentence occurs: *In the event that DEC's estimated winter peak loads and temperatures are overstated and their summer peaks remain dominant, the lower growth and peak demands combined with a predicted increase in solar* *generation eliminates or significantly reduces the need for 435 megawatts of CT capacity planned for 2025 in DEC's IRP.* Is that a correct reading of that sentence?

A (MR. HINTON) Yes. I actually -- it was my efforts that underlie that statement. Basically I took their IRP and I changed the growth rates for the peak demand and watched how it impacts reserve margins and whether that unit was still needed. And on a capacity level perspective, not energy, that need could be pushed out I think in at least another year, maybe to 2026, as opposed to 2025.

MS. MITCHELL: Thank you. I have nothing further.

CHAIRMAN FINLEY: Other intervenors.

MR. LEDFORD: NCSEA does have just two questions for Mr. Lucas, if that's okay.

CROSS EXAMINATION

BY MR. LEDFORD:

Q Mr. Lucas, are you familiar with Ms. Harkrader's testimony about the commitments that a QF makes when developing a project, specifically early in the process?

A (MR. LUCAS) Yes.
Q Thank you. And do you believe that the interconnection process provides a certainty to a QF as to when their project will be interconnected to the grid as it's operating currently?
A No.

MR. LEDFORD: Thank you.

MS. BOWEN: I have just a few questions for Mr. Hinton and then I think to the panel or, excuse me, yes, to Mr. Hinton and then to the panel.

Lauren Bowen on behalf of Southern Alliance for Clean Energy.

CROSS EXAMINATION

BY MS. BOWEN:

Q You've talked a little bit about Georgia and I think you've alluded to this, so I think you're aware the Georgia Public Service Commission has mandated certain -- that the Utilities in that state obtain certain amounts of megawatts of solar energy and renewable energy as a result of some IRP proceedings in that state; are you aware of that?
A (MR. HINTON) Yes, I am.

Q So, as an example, in 2013-2014, the Commission, subject to check if needed, but the Commission mandated that the Utility, Georgia Power, acquire approximately 500 megawatts of solar power over the next -- over the following few years. Are you aware of that?

A Yes. And it went through a competitive bidding process.

Q Uh-huh, it did, that's right. And would you agree that those mandates coming out of the IRP proceeding, that that's been a significant contributor to some of the solar growth they've seen in Georgia in 2015 and 2016?

A Yes. I talked extensively with Jamie Barber about that. Several of those projects were located I believe on military bases and the challenge to the Commission Staff at that time was to ensure that the costs paid for the solar facilities was at or below their avoided costs. So it's a rather complicated process to go through as we did when Duke, DEC and DEP, acquired solar facilities in North Carolina.

Q And it's okay if you don't remember this, but do you recall whether, when they looking at the avoided costs and coming in under that, were they looking at the projected avoided costs over time?

A Yes, they were.

Q Thank you. And then a few questions for the panel as a whole. The Companies in this proceeding have raised concerns about integrating more solar power onto their systems in the state. And it's my understanding that the Public Staff change in positions from prior avoided cost proceedings to this avoided cost proceedings in part are driven by an acknowledgment of those concerns that had been raised; is that fair?

A (MR. METZ) Yes, that is a fair statement.

Q Thanks. And then so my question is are there other steps that the Utilities can or should be taking to better integrate solar power going forward in North Carolina or at this time?

A That -- I mean, that is a fairly extensive question and require I think a lot of speculation on my part is I'm not the system operator and I don't fully contemplate the ins and outs that would be required. I could speak generically but I don't know how it would be applicable to avoided cost.

A (MR. HINTON) For generation planning in the long-term then there are a couple of things they could do as was mentioned yesterday. They can invest in more quick start generation units. That would help I think with their system. There's a host of those machines out there that they -- they have limited quick start facilities on their Duke systems, DEP and DEC. They have some but not a whole lot.

A (MR. LUCAS) The only thing I'd like to add, in last year's DEP's REPS case came out about payment for costs that the Utility had to incur to interconnect QFs, and the Public Staff's supported position was that those QFs should pay for system upgrades if necessary to get them interconnected.

Q And in most or all cases the QFs are paying for the system upgrades currently; is that right?

A We believe to a large extent they are. We don't know absolutely exactly who's paying for every last dollar of utility commitment to interconnect a QF.

A (MR. HINTON) And I'd like to add one final note that -- and to go on what Mr. Lucas just said, if we don't know about how all of the other costs are actually absorbed to this point in time, an integration cost study would be one step further and we're hoping the Companies will be in a position to release one in the near future because that way -- right now there's costs being shed. They're either being collected at the interconnection cost study or they're getting through base rates and we'd like to make sure that all of the costs of solar are appropriately identified the best that we can.

Q And just to follow up, the Utilities could send more precise signals or provide more information -- I think we've heard about this, but provide more specific information to QFs at an earlier stage about where to optimize -- where to optimally locate projects. Is that another option? I believe Mr. Freeman testified to that.

A (MR. LUCAS) That could be done. There's some security requirements for how much information the Utility can release so that would be difficult to answer without more information from the Utility.

A (MR. METZ) But I would like to add on that. I

think that was the Utilities' proposal of looking ahead in their request for proposal process in future proceedings is to better share that information or to provide transparency of where they need that.
Q Thank you. Just one or two final follow ups. So I think another one we heard was gathering more information or doing some additional forecasting about QF power and particularly solar power and what that means for the Utilities. I believe Mr. Holeman testified to that. Would you all agree that would be helpful as well for the Utilities?
A (MR. HINTON) Yes, I'm sure as you've heard there is a great interest in trying to predict solar generation and that's something that the industry is moving to.
Q Thank you.
A (MR. METZ) I mean, but just to provide potential of what is going on now, I mean, it's looking ahead and, yes, there is ways to improve through this process. I think we're making improvements. But at some point, and I think what we're doing now, too, is addressing the real time that is

occurring right now, even if we started implementation of forecasting, I mean, there's going to be a cost associated. Well, who's ultimately burdening the necessity to provide this forecasting. But it's going to take a period of time, I cannot define it, before we can say that is a good forecasting model to be applicable all the way (ASK DUSTIN) interfacing back to the system operator and then the challenges associated with that.

A (MR. HINTON) And I just want to -- there's one perspective I'd like to add and not to say these short-term issues are not important, they're very important. But we're after the long-run avoided costs that's over 10 years and previously did over 15 years. It possibly could be done, if the Commission accepts, it could be as short as two years but it's still a long-run marginal cost exercise.

Q Thank you. And just one final question. I think one other potential way to better integrate solar power that we've heard about is the storage, so pumped -- pumped hydro storage or battery storage. Would y'all agree that that could also

help better integrate solar going forward?
A (MR. METZ) Again, storage is a technologies-specific function. There's going to be a cost associated with it. Generic studies, and I have not gone through extensive review on my part, but right now typical storage and I'll just say battery storage is just not in the money, as a generic term, there's more analysis, there's more in-depth analysis. There's other providers that are doing more studies on how to integrate battery storage. And in terms of the question for utilization of hydro, there's other complexities that need to go into that because you also have to evaluate environmental concerns, discharge when they can or cannot be utilized and how that's going to differentiate the model that's already being utilized by the Utilities and try to further integrate that. I mean, I believe it is an important step moving forward due to the amount of QF generation that we're having in our state but it could be complex.
Q Thank you.
A (MR. HINTON) And in their -- the Companies' IRP, they are considering or reviewing at a serious

level the -- of solar in a battery generator. So I think the Utilities are making a good faith effort to examine the economics of those systems.

MS. BOWEN: Great. Thank you. I have no further questions.

CHAIRMAN FINLEY: Redirect.

MR. DODGE: Thank you, Chairman Finley. Several questions I'll try to go through quickly.

REDIRECT EXAMINATION

BY MR. DODGE:

Q Mr. Hinton, earlier Mr. Breitschwerdt was discussing Georgia, the Georgia avoided costs and the development of solar in Georgia, and Ms. Bowen was also just asking some questions about this and indicated that much of the activity in Georgia is taking place under a Commission-approved RFP process in Georgia. Do you know how many projects in Georgia have been built under the standard rates that are available in Georgia?

A (MR. HINTON) My brief understanding with talking to Ms. Barber is that there's very little.

Q Thank you. And you recall Mr. Breitschwerdt asked you to read from the 2014 Commission's

Order in the avoided cost proceeding? He asked you to read a paragraph describing DEC and DEP's further intentions that continue to use market-based data going forward.

A Yes.

Q And I'd just note this is on page 26 of that Order, that was a summary of DEC and DEP's Joint Reply Comments that he was quoting from. Turning to page 27 of that where the Commission's discussions and conclusions on that section is, I'm going to read from, it's kind of in the middle of the paragraph of the Discussions and Conclusions section. It reads *the Commission acknowledges that forecasting natural gas and coal prices over the next 15 years is challenging and that forward market prices may provide a better snapshot of prices over the near and short-term future; however, forward market prices do not reflect the same level of analysis and consideration given to the development of long-term forecasts as performed by firms whose experience is in long-term forecasting*. Did I read that correctly?

A Yes. The only thing I'd like to add on that, there hasn't been any discussion to date on why the Company does not use futures for coal price forecasts, it's because their illiquid.

Q And my point was just to note the Commission's discussions on that, not necessarily the -- just the context of the two paragraphs. And just to restate the Public Staff does not have any objections to the Companies' proposal to use, rely on market data for up to five years for purposes of IRP and avoided cost planning.

A We support that, yes.

Q We support that. Thank you. Switching a little bit to the subject of legally enforceable obligations. You may recall Mr. Breitschwerdt handed out, this is Cross Exhibit Number 3 that was a list of solar CPCNs that were issued by the Commission in late October of 2016. And Mr. Breitschwerdt characterized the Public Staff's review of those as for the purpose of helping the QF establish its LEO. When we review CPCNs to present to the Commission for approval, are we reviewing those for the purpose of helping the QF establish the LEO?

A (MR. LUCAS) No.

Q Are we reviewing them to ensure that they're in compliance with the Commission's Rules and they've completed all of the necessary steps?
A Yes.
Q And if they completed the necessary steps and we didn't -- we'd held up or delayed those; would that be appropriate?
A No.
Q Thank you. Let's see, also, Mr. Breitschwerdt also handed out Exhibit 4 which is a Cypress Creek Application for the Slender Branch Solar Application and he had you refer -- this is marked as Cross Exhibit Number 4 -- and, again, the same point Mr. Breitschwerdt made, there's exhibits numbered within this but he pointed you to Exhibit 3 within that cross examination exhibit. If you turn to Exhibit, I believe this is Exhibit 6, and it's a page labeled Slender Branch Solar CPCN Statement. Do you see that page, Mr. Lucas? It's the third to the last page I believe.
A (MR. METZ) Exhibit 8 or Exhibit 6?
Q I'm sorry. It's actually the very last page of Exhibit 6.

A (MR. LUCAS) Okay, I've got it.
Q And have you reviewed these statements previously in CPCN applications?
A Yes.
Q And just to characterize this, this exhibit, this is a response provided by the Utility regarding the impacts on the reserve margin and the capacity for -- associated with this large CPCN application?
A Yes. This is a statement from the Utility about its ability to accept the power.
Q And for the -- under the Commission's Rules, they're required to provide this information for the larger CPCN applications that are greater than five megawatts, or plan to sell for more than five years, or if they're a solar facility greater than 25 megawatts?
A Yes.
Q Thank you. Do you have the email -- let's see if I have the email from Amparo Nieto that was -- let's see if I can identify the exhibit. This is DEC/DEP Cross Examination Exhibit Number 5.
A (MR. HINTON) Yes.
Q Just two quick points. Mr. Breitschwerdt

highlighted two sections in here for you to read and he noted that this was sent at 1:40 a.m. by Ms. Nieto in response to an email from you. At the last paragraph following the section that was highlighted, Ms. Nieto again at 1:40 a.m. responding to your email, it stated that *I would need to understand the situation better with some more information*. I just wanted to note that this was a response to an email to you provided at a late night point so this is not an affidavit or a statement provided by Ms. Nieto in this proceeding?

A No. And, in fact, I never -- unfortunately never could get together and discuss things but this was the extent of our communiques and she does clearly say I need more information to better understand the situation in North Carolina.

Q Thank you. Then Mr. Breitschwerdt asked a couple of questions of both Mr. Metz and Mr. Hinton about the PAF and specifically about the payment, the relationship between the on-peak availability and the payment of the PAF. Is it your understanding that by paying only during the on-peak hours in part that's structured in that way to provide a price signal to the QFs to the value of the capacity that they're providing during those on-peak hours.

A Correct. That's one of the key intentions of that PAF is to do just that. There clearly is value of capacity generated by the solar providers as well as other QFs.

Q Thank you. And with regard to the questions about the LEO, Mr. Breitschwerdt asked about the level of commitment to build a facility on the part of a QF. This is to Mr. Lucas. Mr. Lucas, recognizing that you're not a developer of these projects, but you responded that they had not committed to build, but to the extent the QF is committing, they're committing to sell the energy and power to the Utility; is that correct?

A (MR. LUCAS) Yes, if they build the facility.

Q But is there ability to actually construct uncertain based on the outcome in the interconnection process?

A Oh, yes, they'll make that decision of whether to build or not based upon the interconnection process and the outcome of that review.

Q And to the extent the Public Staff's position is linking the timeframes in the interconnection process it's to recognize that the critical nature of that information?

A Yes.

Q Thank you. And then the last question I have, Ms. Bowman asked a couple of questions about integrating solar, better integrating solar to the panel. And two points I wanted to make, is it correct - and this may be most appropriate to Mr. Lucas - in the REPS docket the Utilities have R&D funds available and they have been utilizing those funds for looking at some of these solar integration costs and studies?

A Yes, Utilities have used that research and development funds to pay for research on integration of solar.

Q And we're supportive and interested in the outcome of those studies?

A Yes.

Q Thank you. And Mr. Hinton responded regarding the IRP and it may result in different resource selection. And to the extent these decisions were made regarding what type of generation units would be selected in the future, that would be based on an analysis of the least cost resource plans available for the Utilities; is that correct?

A (MR. HINTON) Correct. All IRPs and this is -- our state is a least cost state, so that's how the Utilities operate their IRPs and that's how we review them into those -- of least cost.

MR. DODGE: That's all I have. Thank you.

CHAIRMAN FINLEY: Commission questions. Commissioner Bailey.

COMMISSIONER BAILEY: Good afternoon. I'll try to keep my -- I've narrowed down any questions at the risk of being shot in --

(Laughter)

-- carrying this docket further on in the day.

EXAMINATION

BY COMMISSIONER BAILEY:

Q I will give you a break, Mr. Hinton, and I'll start off with Mr. Metz here. And maybe what I'm asking for is either, when I get through making the statement, you either agree or you don't agree, okay.

A (MR. METZ) Yes, sir.

Q Based on what I hear from the testimonies from Mr. Holeman at Duke and reading through his testimony that no matter what happens in the future -- and obviously they've got another 1000 or so kilowatts to come on in the next year and even more after that -- that the LROL, the L-R-O-L limits that he was talking about that does exist and that is for real and that's a NERC -- and they use that basically to make sure they don't violate NERC standards and it's even going to get worse after January 1, 2018, as I understand it. So at some point in time, Duke Energy Progress is going to have to stop -- start dumping excess energy to some other BA, either PJM or SCANA or somebody, because it's unlikely that at some point in time they can't take it west so it's most likely going to go north or south at that point in time. The -- are you in agreement that that's going to happen?

A So maybe to address this, a couple of bullet points. So the LROL as Duke has stated that that is their component. The LROL takes in multiple, from my understanding, takes in NERC standards which is inclusive of the CPL standard, which is reflective of like n-1, they're now P codes which is a totally different subset, but it takes in considerations of why they need to stay within NERC standards. So I agree that the LROL is relevant and it's their best industry experience, operating experience to stay within the NERC standards.

Q Okay. Well, based on the last six months' history we're getting in more solar or QFs coming online. Whether it's solar or whatever kind of QFs, they're going to find their self, if they can't take this west in their JDAs to Duke Energy Carolinas they've got a real issue in terms of now they're down here, they've got no load situations, they've got a significant amount of QF power on their systems. What are they going to do?

A So to potentially address probably just the JDA component of that, the JDA as mentioned before is an economic tool. It's not a system operation tool. So I really say -- even dislike saying it's a tool from an economic standpoint. The Utility is going to be faced with a challenge and I think that's why we made our statements in here that they need to file with the Public Staff and the Commission for their curtailment issues and hopefully some of those -- that component, especially dealing with the JDA is vetted through that process.

Q That's a good segue into my next question. So, as I understand when you read your summary when you started this afternoon, this morning, that basically you're recommending that the Commission comes up with some type of more definitive emergency operation definition; is that right? I mean, in other words, it appears to me that for whatever reason they don't, since these are QFs and they are under PURPA they don't -- and we really -- evidently they haven't -- we haven't defined in North Carolina a curtailment schedule or queue or however that takes place, that we should as a Commission in our new Order come up with some definition, or basically ask for a collaborative process to go forward very shortly to come up with some type of curtailment transaction that can take place when they find their self up against NERC violations.

A A collaborative process or a stakeholder group could be one avenue that the Commission would request. In terms of redefining or creating a definition, as I stated in my testimony on page 10, according to the existing CFR - I'm not trying to belabor here - the CFR already as stated *means a condition on the utility's system which is likely to result in an imminent significant disruption of service*, so on and so forth. And I think that's why I chose my language in my testimony to request to the Commission just to affirm, to acknowledge to all stakeholders that the CFR is already stating that the Utilities could do this. Simplified, please don't be surprised if we need to do this due to system operational challenges that are existing.

Q I'm not -- obviously, I'm not a lawyer so I -- as I understand it, there seems to be some grey areas there about when does the Utilities actually declare an emergency situation. They obviously, through a little -- from a legal standpoint they may not want to go down that road. That's just my take. That was an -- that was an editorial that I -- that wasn't really a question to you. So based on that, if a Company has to dump power to another BA, is that in its own ratepayers' advantage or disadvantage?

A So without going through the numbers that were in the confidential exhibit, I would say they speak for themselves on what's taking place on what one BA is paying for energy as approved by the avoided cost rates as a backwards looking function, then being potentially fair to the other utilities taking it is at their - what is it - on the margin -- on the margin price, economic term, I apologize.

Q I would say, do you agree that it's not likely to be in the North Carolina ratepayers' advantage if they have to start dumping excess power to other BAs?

A For the -- I would define it as a disparity. The one who's having to get rid of it is at a disservice to the individual who's getting - in my words and my opinion - a good deal for the other balancing area. It doesn't seem quite fair to me.

Q That's fair, okay. Back over to Mr. Hinton. Have we missed the boat here in this docket? We're not taking more of the South Carolina, what's coming on board in solar or other QFs in South Carolina. We haven't really spent a lot of time talking about that and that really bothers me that we've sort of been concentrating obviously on North Carolina. But since the BAs go over into South Carolina for Duke Energy Progress and Duke Energy Carolinas, we could be having a situation that we've really not really been talking about in this docket. Do you agree with that or disagree with that?

A (MR. HINTON) I mean, I guess I agree with it but not -- my understanding of the QF development in South Carolina is still relatively limited.

Q Okay.

A They have, from a rates perspective, there's very little development in South Carolina. They have the same basic rate structure we have in North Carolina. Over the years there's been some differences but now they're basically saying the fact that we don't have the tax credits in North Carolina anymore, I think, gives me pause to believe the future is not going to be like it has been in the past where it will be going into a different world going forward. There's still a lot in the queue and that's the reason why -- that basically for a lot of my testimony. I'm hoping this is a temporary issue. But, then again, if panel prices fall this could become a bigger issue even down the road, and we -- the Commission has no control of that actually.

COMMISSIONER BAILEY: In the interest of time, I won't get into the natural gas forecasting issues.

CHAIRMAN FINLEY: Commissioner Brown-Bland.

EXAMINATION

BY COMMISSIONER BROWN-BLAND:

Q Mr. Hinton I'll start with you. Why do you believe -- this refers to your recommendation on page 26 regarding the seasonal allocation factors. And just succinctly as you can, why do you believe we have sufficient information at this point to support your recommendation for a shift with more emphasis on the winter as opposed to other witnesses, I think, we heard yesterday who thought maybe we need more information before we make a change and thought 50/50 could be right or some combination in between?

A (MR. HINTON) I have not a whole lot of information to be honest with you. It was somewhat of an uninformed judgment call. As you'll recall the Companies proposed going to 80 percent winter and they were at 40 percent winter before so they took a very large jump. In the IRP, we clearly address issues with the reserve margin study and I had concerns personally with their load forecasting. Years ago I forecasted loads and I know how there's a degree of subjectivity involved in forecasting. I just felt it was appropriate not to make such a large change in the seasonal allocation until we have more information.

Q But somehow that means you do think it's appropriate for some kind of a change at this point in time?

A Yes, I can accept some because -- but to be honest with you I don't want to say their seasonal allocation is not important. It is important but it's not a driver. To be honest with you, in the rate calculations it's not.

Q Okay.

A It is an issue but it's not a driver. The bigger drivers are things like zeros and then the two-year refresh has its own risk issues. But as far as the rate calculations, the cost of capacity drives the capacity credits. And the fact that we, the Public Staff has agreed with the use of zeros took a lot of money off the table.

Q Now, onto the Performance Adjustment Factor, so I think this will be Mr. Hinton and Mr. Metz here. But just in understanding the purpose of this Performance Adjustment Factor, it doesn't add to the avoided cost rate that the Commission sets, but would you agree it's a way to allow the QFs an opportunity to recover the full avoided cost rate that we set, whatever that is?

A Well the -- maybe I understood you. But it does add to the avoided cost rates. I mean, it is what it -- you take the avoided capacity costs and you go through the -- and you make the adjustment to the CT to get that avoided capacity cost and then you times it by 1.2 or times it by 1.05 or 1.16. So it really does have a direct impact on the rates. The second part is does it provide -- and that's a lot of the underpinning of the PAF. I mean, the fact the Utilities don't build to meet their peak -- they build to be at their peak plus a reserve margin. And that's, of course, due because nothing the -- every utility, every plant has got a likelihood of a forced outage rate. That's just the reality we live under. And that -- the fact that we make concessions for that in planning suggests the same kind of concessions should be done for the QF. And that concession means that they can generate 86 percent of the time and still get their off-peak -- their full capacity rate or under I think our recommendation now, use the 1.16 the equivalent rate would be 83 percent.

A (MR. METZ) 86. You've got it backwards.

A (MR. HINTON) Forgive me. But we -- there is that equity issue about giving the QF the opportunity to earn its full capacity credit and we think that's appropriate and that's what is one of the key underpinnings of our --

Q And so within the avoided cost rate that we set, there's the capacity portion and the energy portion. The energy portion is always going to be based on the energy delivered --

A Correct. The avoided --

Q -- and the capacity portion is basically, I know there's more detail to it, but basically designed to recover the fact that you, that the QF creates the facility in the first place, the building, the construction, capital and other costs, right?
A (MR. LUCAS) The QF gets paid for capacity by something called the capacity credit it's paid for energy generated during the peak period on top of the energy payment. If it doesn't generate at all during the peak period, it doesn't get paid for anything.
Q Energy or capacity?
A Correct.
A (MR. HINTON) Because everything is paid on a kWh basis.
Q So, Mr. Metz, is it -- it's fair to say that the Public Staff and Duke have calculated the PAFs differently in this docket, correct?
A (MR. METZ) That is correct.
Q And is it fair to say -- I'm trying to get my head around this -- that you have -- the Public Staff has made its calculations around peak hours and the Company has used either seasonal or system peak; is there a difference?

A I can't speak specifically to what Witness Snider did in his rebuttal as we've not reviewed those numbers. My availability factor was based on an annual, no 24/7/365, so it did not segregate peak hours from non-peak hours. Again, it was in the context of a generic QF, non-specific to technology, not knowing when they could or could not contribute as there is a value to capacity regardless of when they're contributing.

Q And with respect to the Company, your 86 percent represents what?

A The amount of times that the plants were able to be called upon to provide electricity. So let's say 86 percent was the exact number so that would be reflective at 14 percent on a weighted capacity would take into consideration of either forced outages and maintenance cycles, and I believe that is sort of the split in the road of where Duke Energy is saying we're excluding the maintenance cycles. And as I've gone through earlier in saying why I think maintenance cycles should be in place due to the maintainability function.

Q And one last question. Have you given any thought to whether it's reasonable or not, I think there was some mention of going to a QF-specific kind of PAF, but in this case, say for example with solar, would it be fair or reasonable or not fair or reasonable in your opinion to allow the solar QF to get the full capacity recovery based on the same availability that the Company has for its company solar?

A I would be supportive in potentially a future proceeding, if the Commission would request that we look at QF technology-specific rates that way we're not discriminatory.

Q So my question in it that the part of the Company you would look at I guess would not be the full system. Is that fair or not fair in terms of how a PAF should work, and the comparison should just be the company solar? Availability or company solar, I guess. And just if you have an opinion?

A Yes. At this time based upon what's been presented in front of me it would be a hard time. In my opinion, I'm open to it just because I would like to take all of the information in and just take a step back.

Q Do you think it would distort, distort or give a clearer picture I guess in terms of the recovery?

A It could provide a picture but the only thing to put it in context is the Utilities' solar generation is part of rate base and general ratemaking, whereas a QF is not. And that's why I would say and take a step back and potentially look at that. But at this time, since I haven't been presented numbers or values, it would be hard to take a step back.

Q Okay. Mr. Hinton, did you want to add or do you want to leave it where he left it?

A (MR. HINTON) I think it's best, Commissioner, if I leave it where it is.

(Laughter)

COMMISSIONER BROWN-BLAND: So while I've got the mike so it won't have to come back to me, I would like to take just a moment of personal privileges they say to -- someone's been on my mind since we've been sitting here during this proceeding and I'd just like to note that and, sort of like an in-memoriam note, and recognize our departed friend and Public Staff colleague Kennie Ellis, who had always participated in these avoided cost proceedings and who had given his service to the State of North Carolina and its citizens, and he's missed during these proceedings. Thank you.

CHAIRMAN FINLEY: Questions on the Commission's questions?

MR. BREITSCHWERDT: No questions.

MR. DODGE: No questions.

CHAIRMAN FINLEY: Very well. The exhibits we have for the panel, the Metz direct examinations 1, 2 and 3, the DEC/DEP Panel Cross Examination Exhibits 1, 2, 3, 4, 5, 6 confidential and 7 confidential, without objection, shall be introduced into evidence.

MR. BREITSCHWERDT: Thank you.

Public Staff Witness Metz Confidential Exhibit 1
(Admitted)

Public Staff Witness Metz Exhibits 2 and 3
(Admitted)

DEC/DEP Public Staff Panel Cross Exhibits 1 - 5
(Admitted)

Confidential DEC/DEP Hinton Cross Exhibits 6 and 7
(Admitted)

CHAIRMAN FINLEY: Anything else to come before the Commission this afternoon? Our usual practice is to ask for post-hearing filings 30 days after the mailing of the transcript. Is there any objection to following that procedure in this case?

MS. FENTRESS: No, sir.

MR. DODGE: No objections.

CHAIRMAN FINLEY: Very well. Thank you all for your participation, and this proceeding is closed.

(WHEREUPON, the proceedings were adjourned.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell
Kim T. Mitchell
Court Reporter II