PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Thursday, April 20, 2017

TIME: 2:00 p.m. - 4:52 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: 7

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

E X H I B I T S

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

CHAIRMAN FINLEY: Mr. Culley, do you have any redirect?

MR. CULLEY: No, Mr. Chairman, no redirect.

CHAIRMAN FINLEY: Let see if there are questions by the Commission. Commissioner Brown-Bland.

EXAMINATION

BY COMMISSIONER BROWN-BLAND:

Q Good afternoon, Mr. McConnell.

A Good afternoon.

Q Just a few questions. And I wanted to know if you would agree or disagree that the avoided costs here in North Carolina, the way PURPA is implemented, is the primary driver in Cypress' decision to locate projects here in North Carolina and want to deal with our investor-owned utilities?

A I think it is a significant driver. The Standard Offer Contract is compelling and simplifies the process to not have to bilaterally negotiate. The original decision was made based upon that fact pattern as well as the state investment tax credit when it was around and we built several of our projects while that tax credit was still available. The property tax abatement and the RECs both help as well but the Standard Offer is probably the most significant piece of that.

Q And, also -- so in addition to the fact that we're in the south and we have a good deal of sunshine here, you mentioned the tax credits, any other factors in terms of availability of land, the price of the land and that kind of thing?

A I think you bring up a good point that I neglected to mention is that the radiance is really solid in North Carolina on top of a lot of cheap available land relative to some of the more metropolitan denser areas where we looked to develop. So certainly there's a lot of facts in favor of development in North Carolina.

Q Are you familiar with the Renewable Portfolio Standard and requirements that we have here in North Carolina?

A Yes, ma'am.

Q Does that in any way factor into the decision to do projects here in our state?

A It did. Originally we were selling the Renewable Energy Certificates per that program back to

Duke. At this point there's not a ton of value because I believe that the Utilities have both met their portfolio standard at this time, to my knowledge. That's me speculating. But at this point there's not a lot of value associated with those RECs.

Q In terms of initial decision to do business here, was it a factor?

A Yes, ma'am.

Q You indicated that, if you consider what Cypress has in the pipeline, you would not agree that the vast majority of your projects were in North Carolina. Are you able to locate where you think the vast majority are either by state or region?

A Region is probably easier. We have a number of projects in the southeast outside of North Carolina. We have a number of projects in the northeast, subject to different incentive programs that allow for favorable development including community solar programs. We have some development efforts in deregulated markets in PJM and ERCOT in Texas. And then we have a number of more QF style models that are in the pacific northwest that we're pursuing. So our development efforts have extended well beyond North Carolina at this time.

Q From your point of view or Cypress', since you indicate those projects are across the nation, are you able -- and, if so, state your qualifiers -- but are you able to give any testimony or idea about how from your view North Carolina's PURPA implementation compares or relates to PURPA implementation across the nation? And I guess more specifically, are there locations that are more favorable than North Carolina's PURPA implementation?

A I'll caveat my entry by saying I am pretty much siloed within finance of the firm and trying to raise capital for our projects and so my day-to-day does not consist of looking at new markets and other opportunities for the firm to develop. I think North Carolina's implementation of PURPA is consistent with the intent of the law to offer avoided cost contracts for developers that have projects that are eligible and so I do think it's a favorable interpretation. I do think other states have similar interpretations. I can't speak to any specific state that's really better or worse with any degree of confidence.

COMMISSIONER BROWN-BLAND: Okay. That's okay, I just wanted your best idea of what you -- based on your own knowledge. That's all I have. Thank you.

CHAIRMAN FINLEY: Are there other Commission questions?

(No response.)

Mr. McConnell, I see that you got your undergraduate degree at the University of Virginia?

THE WITNESS: Yes, sir.

CHAIRMAN FINLEY: And masters degree from the University of North Carolina?

THE WITNESS: Yes, sir.

CHAIRMAN FINLEY: Were you able to pull for UNC in the basketball tournament?

COMMISSIONER BROWN-BLAND: Be careful. This is an important answer.

THE WITNESS: Of course, yes, sir.

MR. MCNAMEE: You're under oath.

(Laughter)

THE WITNESS: Yes, sir.

CHAIRMAN FINLEY: Good for you. Are there questions on the Commission's questions of

Mr. McConnell?

(No response.)

CHAIRMAN FINLEY: Thank you very much. You may be excused.

THE WITNESS: Thank you.

(The witness is excused.)

CHAIRMAN FINLEY: We have DEC/DEP McConnell Cross Examination Exhibits 1, 2 and 3 which we will, without objection, accept into evidence. And we will hold Exhibit 4 in abeyance until we hear further from Cypress Creek.

DEC/DEP McConnell Cross Exhibits 1 - 3

(Admitted)

MR. SOMERS: Mr. Chairman, I understood based on a conversation during the break that Cypress Creek was ready to address your question.

CHAIRMAN FINLEY: All right. Are you ready to --

MR. CULLEY: I'm sorry. I don't understand.

MR. SOMERS: May we go off record just one moment?

CHAIRMAN FINLEY: Yes.

(OFF THE RECORD DISCUSSION)

MR. CULLEY: Sorry, Mr. Chairman, there may have been a slight lack of communication between a few moving parts here. I think we can -- what I can say is Cypress Creek will endeavor as soon as possible to provide that information.

CHAIRMAN FINLEY: Good enough. Who' next? Who's the next witness?

MS. BOWEN: Mr. Chairman, if it's acceptable to the Commission, we've spoken with counsel for North Carolina Sustainable Energy Association and would like to swap order with him so that Dr. Vitolo would go next in line.

CHAIRMAN FINLEY: Very well.

THOMAS VITOLO; was duly sworn and testified as follows:

DIRECT EXAMINATION

BY MS. BOWEN:

Q Dr. Vitolo, please state your name and business address for the record?

A My name is Thomas Vitolo. My business address is 485 Massachusetts Avenue, Cambridge, Massachusetts.

Q Dr. Vitolo, did you cause to be prefiled direct testimony in this docket?

A I did.

Q And do you have any changes or corrections to your prefiled testimony?
A I do not.
Q If the questions put to you in your testimony were asked at the hearing today, would your answers be the same?
A They would.
Q Was the exhibit to your testimony prepared by you or under your direction?
A Yes.

MS. BOWEN: Mr. Chairman, I would move to have Dr. Vitolo's prefiled direct testimony entered into the record as though given orally from the stand, and to have the exhibit attached to his testimony identified as premarked, Vitolo Exhibit 1?

CHAIRMAN FINLEY: Dr. Vitolo's direct prefiled testimony consisting of 46 pages filed on March 28, 2017, is copied into the record as though given orally from the stand, and that his exhibit as premarked in the filing is so marked for purposes of this case.

MS. BOWEN: Thank you, Mr. Chairman.

Vitolo Exhibit 1
(Identified)

(WHEREUPON, the prefiled direct
testimony of **THOMAS VITOLO** is
copied into the record as if given
orally from the stand's.)

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Mar 28 2017

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Tommy Vitolo, and I am a Senior Associate with Synapse Energy Economics (Synapse) at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have a PhD in systems engineering from Boston University; a master's in financial and industrial mathematics from Dublin City University, Ireland; bachelor's degrees in applied mathematics, computer science, and economics from North Carolina State

University; and more than eight years of professional experience as a consultant, researcher, and analyst.

Since joining Synapse in 2011, I have focused on utility resource planning, variable resource integration, avoided costs, and other issues that typically involve statistical analysis, computer simulation modeling, and stochastic processes. I have filed testimony or reviewed utility filings in 24 states and two territories, primarily by evaluating numerical analysis, modeling, and decision strategies of resource plans and certificates of public convenience and necessity applications.

On topics related to the costs and benefits of distributed generation—including net metering issues, avoided costs, bill impacts, and appropriate rate design—I have developed or submitted testimony in California, Massachusetts, Maryland, North Carolina, South Carolina, Utah, Vermont, and Wisconsin. Additionally, I have performed cost and benefits analyses of distributed generation for systems located in Maine, Massachusetts, Mississippi, New York, North Carolina, and Washington DC.

Prior to joining Synapse, I worked as a research assistant at MIT Lincoln Laboratory. My CV is attached as Vitolo Exhibit 1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Southern Alliance for Clean Energy (SACE).

Q. Have you testified previously before the North Carolina Utilities Commission ("the Commission")?

A. No, though I assisted my colleague J. Rick Hornby with the development of testimony filed in Docket No. E-100, Sub 140, and as a result, I am familiar with some of the issues raised by the parties in that proceeding.

Q. What is the purpose of your direct testimony in this proceeding?

A. The primary purpose of my testimony is to provide an analysis of the proposals by Duke Energy Carolinas, Duke Energy Progress, and Dominion North Carolina Power (collectively, the "Companies") to change avoided cost standard offer contract terms and conditions for qualifying facilities (QFs) other than run-of-river hydroelectric QFs, and to evaluate the Companies' proposed methodological changes to calculating avoided cost rates.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Vitolo Exhibit 1 (Resume of Thomas John Vitolo, PhD).

Q. Please summarize your conclusions and recommendations.

A. With respect to standard offer contracts, I recommend the Commission maintain current policies by

1. retaining 5 megawatts (MW) as the threshold for renewable QF eligibility for standard offer contracts;
2. retaining the option of a 15-year standard offer contract; and
3. requiring the utilities to include fixed rates for all portions of the standard offer contract.

With respect to avoided cost calculations, I recommend the Commission

4. maintain the current 1.20 Performance Adjustment Factor (PAF);
5. maintain the peaker methodology, including the requirement of paying avoided capacity cost payments in all years;
6. reject the proposal by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (collectively, "Duke") for revising the capacity payment split among summertime and wintertime hours, instead assigning 80 percent summer for 2017 and 2018, and a recalculated percent for all years thereafter based on corrections to their study;
7. require Dominion North Carolina Power ("Dominion" or "DNCP") to continue compensating for avoided line loss; and
8. require Dominion to model its avoided energy costs with a 100 percent available resources.

2. OVERVIEW OF PURPA AND PROCEEDING

Q. What is PURPA?

A. The Public Utility Regulatory Policies Act of 1978 (PURPA) is a federal statute enacted by Congress in 1978. PURPA has been amended several times since its enactment, most recently in 2005. Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.[1] The Federal Energy Regulatory Commission (the FERC) is charged with interpreting and implementing PURPA by establishing rules and issuing orders. Under PURPA, the FERC has delegated to state regulatory commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers, known as qualifying facilities or QFs.

Q. Please describe how PURPA relates to the avoided cost rates and contract terms being set in this proceeding.

A. In the previous biennial avoided cost docket, the Commission provided a succinct overview of PURPA's requirements:

> Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates that are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.[2]

The Commission has chosen to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. Through those proceedings, the Commission has established the methodology and the rates by which North Carolina's investor-owned utilities, the Companies in this proceeding, purchase

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[1] 16 U.S.C. § 824a-3(a).

[2] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140 (Dec. 31, 2014) ("E-100, Sub 140 Phase I Order") at 3.

energy and capacity from QFs under PURPA. The Commission also has reviewed and approved other related matters involving the relationship between the Companies and such QFs, such as terms and conditions of service, contractual arrangements and interconnection charges. Throughout those proceedings, the Commission also applies relevant FERC orders relating to PURPA implementation in reaching its findings and conclusions.

3. COMMISSION'S 2014 DOCKET

Q. Please provide an overview of the previous avoided cost proceeding.

A. In the last biennial avoided cost proceeding before the Commission, Docket No. E-100, Sub 140, the Commission considered a variety of avoided cost input parameters during "Phase I" of the proceeding, many of which the companies seek to revisit in this proceeding. After fully litigating these issues, the Commission issued an "Order Setting Avoided Cost Input Parameters" on December 31, 2014. In its Order, the Commission made numerous findings of fact. Among its determinations, the Commission required that the Companies continue to apply the peaker methodology for establishing avoided energy payments; continue to apply the peaker method with publicly available industry sources for establishing avoided capacity payments in all years of the contract; utilize a 1.2 PAF in their respective avoided cost calculations for all QFs other than run-of-the-river hydroelectric facilities with no storage capability; account for the fuel-hedge value of QFs; continue to follow their previously approved adjustments for line losses; continue to offer standard offer avoided cost contracts to QFs under 5 MW; and continue to offer standard offer contracts with a maximum term of 15 years.[3]

4. ANALYSIS OF COMPANIES' PROPOSALS TO CHANGE STANDARD OFFER CONTRACTS

Q. Did the Companies propose any significant changes to the standard offer contract structure?

A. Yes. One or more of the companies proposed changes, including the following:

1. reducing the maximum capacity for standard offer contracts from 5 MW to 1 MW;
2. eliminating the 15-year option for standard offer contracts; and
3. changing the payment associated with avoided energy every two years.[4]

I will make recommendations on these topics.

The Commission Should Maintain the 5 MW Eligibility Threshold for Standard Offer Contracts

Q. What is the maximum capacity for which renewable QFs are eligible for a standard avoided cost rate structure under the current tariffs?

A. DEP's Schedule PP-1, DEC's Schedule PP, and DNCP's Schedule 19-FP all include eligibility for renewable QFs up to 5 MW in capacity.

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[3] E-100, Sub 140 Phase I Order at 7-8.

[4] The Companies have recommended several other changes, including the timing of the legally enforceable obligation (LEO). My testimony's failure to address these changes does not imply agreement with those changes. Additionally, my testimony is focused on QFs other than hydroelectric QFs with no storage capability.

Q. Are DEC, DEP, and DNCP proposing to reduce the maximum capacity for which renewable QFs are eligible for the standard avoided cost rate structure?

A. Yes. DEC, DEP, and DNCP are all proposing to reduce the eligibility from 5 MW to 1 MW.

Q. Will this proposed reduction from 5 MW to 1 MW have negative repercussions?

A. I believe that reducing the maximum capacity for which renewable QFs are eligible for a standard avoided cost rate structure from 5 MW to 1 MW will have several negative repercussions. These negative consequences relate to the lengthy, resource-intensive, power-imbalanced bilateral negotiation process, the significant loss of economies of scale, and the ramifications of a significant increase of interconnection requests or bilateral negotiations.

Q. Please describe your concerns associated with the bilateral negotiation process.

A. QFs that do not qualify for standard offer contracts must instead negotiate with the utility company to reach an agreement in order to sell their power under PURPA. The bilateral negotiation process can take many months to resolve.[5] The bilateral negotiation process is also resource intensive: for each "uncontested" PPA, the utility requires roughly 25 hours of staff effort.[6] Of course, the QF must also put considerable effort into a contract negotiation. In addition to taking considerable time and resources, there is often a significant power imbalance in

[5] DEC and DEP Response to Public Staff Request 4-3, Attachment.

[6] DEC and DEP Response to Public Staff Request 4-1.

the negotiation, as the QF has one potential customer – the incumbent utility where the facility is located. Additionally, the QF developer, on the other hand, must invest significant resources in developing the QF project before actual construction. In contrast with the utility, failure to sign a contract results in significant loss for the QF developer. A standard contract offers substantial benefits – the utility uses fewer resources in contract negotiations and in not impeding development of a local resource that is available at avoided cost, and the developer also sees a significant reduction in contrast negotiation risk, expense, and delays.

Q. Please describe your concerns associated with a loss of economies of scale.

A. A solar photovoltaic (PV) QF project has both fixed costs and variable costs. The variable costs grow predictably with the size of the project, such as the total cost of the panels, inverters, and land. The fixed costs do not grow with the size of the project. These costs include legal, administrative, and some engineering costs. As such, a larger project has a lower total cost per kilowatt than a smaller project. Reducing the capacity limit for standard avoided cost rates raises the price of the project per kilowatt, because the developer must either forego economies of scale and build a smaller project to avoid the costs and risks of negotiation, or retain the economies of scale of the larger project but also bear the cost and risk of a bilateral negotiation. Because standard offer contracts of 5 MW in size allow the QF developer to retain the economies of scale and avoid the cost and risk of negotiations and still arrive at a fair avoided cost, it results in lower costs overall.

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Q. Please describe your concerns about the ramifications of significantly more interconnection requests.

A. One potential outcome of reducing QF eligibility for a standard offer contract from 5 MW generation capacity to 1 MW is a dramatic increase in the number of projects under development. To the extent that QF developers' limits are associated with access to capital or ability to procure solar PV hardware, the developer may simply develop as many projects as necessary to build out a portfolio of QF projects that, in aggregate, total a targeted capacity. Should the proposed capacity threshold change induce a significant increase in the number of QF projects, it will also induce a significant increase in the number of interconnection studies the utility must perform. This outcome appears to impose an additional and unnecessary cost on the utility and QF developers. Should the proposed capacity reduction induce more total projects, this change will have imposed economic inefficiency that is avoided by providing a standard offer contract available to projects up to 5 MW in size.

Q. Please describe your concerns about the ramifications of significantly more bilateral negotiations.

A. Another potential outcome of reducing QF eligibility for standard offer contracts from 5 MW generation capacity to 1 MW is a dramatic increase in the number of simultaneous bilateral negotiations. Developers may maintain a 5 MW size or, seeing no advantage to a 5 MW limitation, instead develop projects in excess of 5 MW. Should the size of the projects remain at 5 MW (or even increase), the utility will now be required to enter bilateral contract negotiations for significantly more QF projects. As discussed earlier, each bilateral contract negotiation requires considerable effort by each counterparty, effort that is avoided with a standard offer contract. Furthermore, should the project size increase, we may see significantly more interconnection studies taking "well in excess of 12 months for the utility to complete,"[7] with the delays and additional costs imposing additional economic inefficiency. A standard offer contract allows the parties to arrive at an avoided cost agreement while avoiding the added time and cost of bilateral negotiations. A standard offer contract available to projects up to 5 MW in size provides multiple benefits and efficiencies.

Q. Has DEC, DEP, or DNCP proposed reducing the eligibility threshold for renewable QFs in the past?

A. Yes. DEC, DEP, and DNCP all proposed reducing renewable QFs' eligibility for the standard avoided cost rate structure to 1 MW in the most recent prior docket, Docket No. E-100, Sub 140.

Q. What did the Commission conclude about reducing the capacity threshold for eligibility in Docket No. E-100, Sub 140?

A. The Commission acknowledged that "delays caused by … negotiating a PPA … place QFs in a difficult position with regard to their ability to secure project financing in a timely fashion and raises project costs."[8] The Commission further recognized that "regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy" and that "there is insufficient evidence that the current framework fails to comply with the

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[7] E-100, Sub 140 Phase I Order at 21.

[8] Id.

requirements of PURPA or otherwise disadvantages QFs."[9] The Commission determined that it was "appropriate to retain the five MW threshold."[10]

Q. What do you recommend the Commission order with respect to maximum renewable QF generation capacity eligibility for standard offer contracts?

A. I recommend that the Commission maintain current policy by requiring DEC, DEP, and DNCP to allow renewable QFs up to 5 MW eligibility for Schedule PP, Schedule PP-1, and Schedule 19-FP, respectively.

The Commission Should Reject the Companies' Proposal to Shorten the Duration of Standard Offer Contracts

Q. What standard offer contract term durations are available to renewable QFs under the current avoided cost tariffs?

A. DEP's Schedule PP-1, DEC's Schedule PP, and DNCP's Schedule 19-FP all allow the QF to choose a five-year, 10-year, or 15-year contract duration.

Q. Are DEC, DEP, and DNCP proposing to reduce the contract duration for which renewable QFs are eligible under the current avoided cost tariffs?

A. Yes. DEC, DEP, and DNCP are all proposing to eliminate the 15-year contract option for non-hydro renewable QFs. DEC and DEP are also proposing to eliminate the five-year contract option.

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[9] Id., at pages 21 and 22.

[10] Id., at page 22.

Q. Is this proposed reduction from a maximum contract duration of 15 years to 10 years appropriate?

A. It is not. Reducing the contract duration jeopardizes project financing and may therefore violate PURPA.[11] Additionally, reducing the standard offer contract duration results in differential treatment between QF solar projects and utility solar projects.

Q. Please describe your concerns about reducing the standard offer contract duration and project financing.

A. It is common for QF projects sized 1 MW or more to require financing. Within North Carolina, the industry has demonstrated a clear ability to finance 5 MW solar QFs with 15-year contracts at the current avoided cost rates. Data responses from the Companies show that at least some solar QFs 10 MW and larger have been built with 10-year contracts as well.[12] However, this does not suggest that projects under 5 MW or over 10 MW will be financeable in the future with contracts of that duration. The Companies have proposed significantly lower payment rates for avoided energy in the new tariffs, citing falling natural gas prices since 2014.[13] Some projects may not be eligible for 10-year financing terms, and for the projects that are, reduced payments to QFs necessitate lower monthly debt payments for the project to have positive monthly cash flow. Reducing the fixed contract duration from 15 years to 10 results in higher

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[11] J.D. Wind 1, LLC, 130 FERC ¶ 61,127, 61,631 (2010); Windham Solar LLC & Allco Fin. Ltd., 157 FERC ¶ 61134, P 8 (Nov. 22, 2016).

[12] DEC and DEP Response to Public Staff Request 4-3, Attachment, Table 1.

[13] See, for example, Direct Testimony of Glen A. Snider, Page 16, Lines 5-10.

monthly debt payments, not lower payments. Reducing the maximum duration of the contract from 15 years to 10 years jeopardizes the ability for QF projects to receive financing.

Q. Please describe your concerns about reducing the minimum contract duration and violating PURPA.

A. In its Phase I Order in Docket No. E-100, Sub 140, the Commission determined that "a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind Orders."[14] The FERC has consistently affirmed the rights of QFs to "long-term avoided cost contracts or other legally enforceable obligations."[15] In 2016, the FERC emphasized that given the need for certainty with regard to a QF's return on investment, coupled with Congress' directive that the FERC encourage QFs, a QF is entitled to a contract "long enough to allow QFs reasonable opportunities to attract capital from potential investors."[16] Similarly, North Carolina law requires that the term of any contract entered into between an electric utility and a new solar electric facility "shall be of sufficient length to stimulate development of solar energy."[17]

The companies have alleged but not demonstrated that 10-year contract durations will allow QFs to obtain financing for project development for projects under 5 MW in size. While some larger QFs may be able to attract capital from potential

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[14] E-100, Sub 140 Phase I Order at 19-20.

[15] J.D. Wind 1, LLC, 130 FERC ¶ 61,127, 61,631 (2010).

[16] Windham Solar LLC & Allco Fin. Ltd., 157 FERC ¶ 61134 (Nov. 22, 2016).

[17] N.C.G.S. § 62-133.8(d).

investors based on 10-year contracts, it may be that many QFs will be unable to do so, particularly smaller QFs. This problem will likely be intensified if the capacity threshold for which renewable QFs are eligible for standard avoided cost contracts is reduced from 5 MW to 1 MW, due to the resultant impairment to economies of scale.

Q. Please describe your concern about QF solar projects being treated differently than utility projects with respect to contract duration.

A. Between August 2012 and the end of 2016, DEC and DEP have negotiated seven renewable power purchase agreements (RPPAs) with solar generators; all seven contracts are for 15 years.[18] DEP has four company-owned solar PV generators in rate base with a recovery period of 25 years and DEC owns 27 PV generators in rate base, each for 20 years.[19] DNCP has three PV generators in rate base, to be depreciated over a 35 year time period.[20] Similar to a longer loan reducing monthly payments as discussed above, a longer depreciation schedule allows for a reduced near-term rate impact, therefore making the investment more attractive. At 15-year contract durations, solar QFs have parity with RPPAs and are at a disadvantage relative to utility-owned solar. Reducing the maximum contract duration to 10-year contracts disadvantages QFs relative to RPPAs and exacerbates the disadvantage QFs face relative to utility-owned PV.

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[18] DEC and DEP Response to Public Staff Request 4-3, Attachment, Table 1.

[19] DEC and DEP Response to SACE Request 2-6.

[20] DNCP Response to SACE Request 2-5.

Q. Have DEC, DEP, and DNCP proposed reducing the maximum contract duration for renewable QFs in the past?

A. Yes. All three companies proposed reducing renewable QFs' maximum contract duration for the standard offer contracts from 15 years to 10 years in the most recent prior docket, Docket No. E-100, Sub 140.

Q. What did the Commission conclude about reducing the maximum contract length for renewable QFs in Docket No. E-100, Sub 140?

A. The Commission noted that some or all of the utilities proposed eliminating the 10- and 15-year levelized rate options in Docket Nos. E-100, Subs 79, 81, and 87.[21] The Commission also rejected similar proposals in Docket Nos. E-100, Subs 96 and 100.[22] In rejecting the proposal again in E-100, Sub 140, the Commission explained that "the FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility."[23] In light of these and other considerations, and consistent with PURPA, the Commission determined that "DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods as standard options to … non-hydroelectric QFs fueled by trash or methane derived from landfills or hog

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[21] E-100 Sub 140 Phase I order at 21.

[22] Id., at page 21.

[23] Id., at page 19 and 20.

waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity."[24]

Q. What do you recommend the Commission order with respect to maximum contract length for renewable QFs?

A. At a minimum, I recommend that the Commission maintain current policy by requiring DEC, DEP, and DNCP to allow renewable QFs eligible for Schedule PP, Schedule PP-1, and Schedule 19-FP, respectively, the ability to select five-year, 10-year, or 15-year periods. The Commission should consider requiring the utilities to offer solar QFs fixed contracts at lengths that match the recovery period of the respective utility's own assets: 20 years for PV assets in the DEP territory, 25 years in the DEC territory, and up to 35 years in the DNCP territory.[25,26]

The Commission Should Reject the Proposal by DEC and DEP to Revise the Avoided Energy Payment Every Two Years

Q. How do the companies' standard offer contracts currently treat energy payments?

A. DEP's Schedule PP-1, DEC's Schedule PP, and DNCP's Schedule 19-FP all contain avoided energy rates that are fixed for the length of the contract. Of course, the biennial avoided cost docket would update energy rates for new QF contracts.

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[24] Id., at page 22.

[25] DEC and DEP Response to SACE Request 2-6(e).

[26] DNCP Response to SACE Request 2-5(d), Attachment.

Q. Are DEC, DEP, and DNCP proposing to change the energy payment schedule for standard offer contracts?

A. DEC and DEP are proposing to change the contractual energy payment schedule. Rather than pay QFs a known energy credit rate for the entire length of the contract, DEC and DEP are proposing to change the rate every two years. DNCP is not proposing this change.

Q. What would the new energy rate be two, four, six, or more years into the multi-year renewable QF standard offer contract?

A. It is impossible to know. DEC and DEP propose to recalculate the avoided cost and apply a new rate every two years. The avoided energy cost is closely tied to the price of delivered natural gas, which has been historically volatile and continues to fluctuate. The new energy payment rate could be higher or lower than the existing rate.

Q. Is this proposed change in the energy payment schedule appropriate?

A. It is not. Failing to make avoided energy payments specific for the length of the contract jeopardizes project financing and would likely discourage QF development contrary to the policy goals of PURPA. Additionally, this proposed change foregoes the rate stability that decoupling some generation from variable fuel prices offers. Furthermore, it results in differential treatment between smaller renewable QFs and other projects. Finally, the FERC has held that QFs are entitled to receive long-term avoided 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."[27]

Q. How will changing the energy payment every two years jeopardize project financing?

A. For a project to get financing at competitive interest rates, it must have low risk of default. One important consideration of default risk is expected cash flow over the life of the debt. Solar PV output is remarkably predictable over the course of months and years. Energy (and capacity) payments that are known to all parties at the time the contract is signed allow the QF developer to demonstrate expected monthly cashflow with a high degree of certainty. Under the DEC and DEP proposals, QF developers in the DEC and DEP territories could no longer demonstrate expected monthly cashflow with any certainty after the first two years. Eliminating the avoided energy rate certainty throughout the life of the contract jeopardizes the ability for QF projects to receive financing.

Q. How will changing the energy payment every two years cause rate instability?

A. The rates that customers pay are a function of the utility's costs. A significant portion of the change in rates from one rate case to another is caused by changes in coal and natural gas fuel costs, as capital costs are already sunk and therefore unchanging. One important benefit that renewables such as wind and solar provide is that their fuel cost is fixed at $0/MWh. This allows for ratepayers to

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[27] J.D. Wind 1, LLC, 130 FERC ¶ 61,127, 61,631 (2010).

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dissociate at least a portion of their retail rate from the variability of coal and natural gas fuel costs, but only if the utility locks in energy prices for those resources. Under the current tariffs, the ratepayers gain a five-year, 10-year, or 15-year energy price hedge each time a QF selects a long-term contract because unlike the energy costs associated with the utility's coal- and gas-fired plants, the QF contract has a fixed energy rate. Eliminating the avoided energy rate certainty throughout the life of the contract foregoes the ratepayer benefit of rate stability.

Q. How will changing the energy payment every two years differ from the way DEC and DEP treat other contracts?

A. Between August 2012 and the end of 2016, DEC and DEP negotiated 10 RPPAs and 22 QF agreements with renewable generators over 5 MW in size.[28] None of these contracts appear to contain a payment rate that was unknown at time of the contract's signing.[29] DEC and DEP have further indicated that they have not evaluated potential adverse impacts on the ability of solar QFs to obtain financing with 10-year contracts with energy rates recalculated every two years.[30]

Q. How will changing the energy payment every two years differ from the way DEC and DEP treat their Company-owned investments?

A. A utility decision to build or purchase a generating asset nearly always includes a long-term obligation to pay for that capital asset. Integrated resource planning and decisions to invest capital in a new generator are substantially influenced by long-

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[28] DEC and DEP Response to Public Staff Request 4-3, Attachment.

[29] Id.

[30] DEC and DEP Response to NTE Request 2-2, 2-3, 2-4, and 2-5.

term forecasts of costs, especially fuel. The utility's return of and on its capital investment is not subject to biannual fuel cost adjustments; it simply collects payments to finance a decision made with the best information at the time, even if that information failed to correctly predict a future energy price. In the Commission's 2014 Phase I Order, it observed that "[w]hile witness Snider's emphases that QF contracts represent long-term fixed price obligations on behalf of DEC's and DEP's customers based largely on forecasts of future fuel prices, the Commission recognizes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects the utilities own self-build options are based upon similar "uncertain" forecasts."[31]

Q. Has DEC, DEP, or DNCP previously proposed not providing energy payment certainty in contracts for renewable QFs?

A. Yes. In the Commission's 2010 biennial avoided cost proceeding, E-100, Sub 127, DNCP—then North Carolina Power—proposed to offer variable avoided energy rates for QFs larger than 100 kW that would be updated every two years. In its July 27, 2011 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, the Commission determined that an avoided energy rate adjusted every two years did not comply with the FERC's recent J.D. Wind order.[32]

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[31] E-100, Sub 140 Phase I Order at 20.

[32] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 127 (July 27, 2011).

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Although DNCP had previously offered avoided energy rates that were adjusted every two years, in light of J.D. Wind, the Commission agreed with Public Staff's finding that "a rate that is reset every two years clearly does not qualify as either a fixed rate or as a fixed formula rate" and required the utility to begin offering fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts in the following biennial proceeding.[33]

Q. What do you recommend the Commission order with respect to DEC and DEP's proposal to no longer fix the avoided energy rates for the duration of long-term contracts?

A. I recommend the Commission reject this proposal. The proposed change jeopardizes the ability of QFs to secure financing because it does not provide fixed avoided energy rates for the length of the contract. This change therefore appears to contradict the Commission's assertion that "a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind Orders."[34] The Commission rejected a similar proposal by DNCP in the 2010 biennial avoided cost proceeding based on J.D. Wind, and the Commission should reach the same conclusion with respect to the Companies' proposed variable rates. The proposed change also eliminates an important ratepayer benefit of fixed price energy contracts – rate stability. Finally, the proposed change fails to treat small PV QFs and other PV generators indifferently.

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[33] Id., at pages 10-11; Public Staff Proposed Order in Docket No. E-100, Sub 127 at 9 (April 29, 2011).

[34] E-100, Sub 140 Phase I Order at 19.

5. ANALYSIS OF COMPANIES' AVOIDED COST CALCULATIONS

Q. Did the Companies propose any significant changes to the methodology for calculating avoided costs?

A. Yes. One or more of the companies proposed several changes, including the following:

1. Reducing the Performance Adjustment Factor from 1.2 to 1.05;
2. Eliminating capacity payments in certain years;
3. Changing the fraction of avoided generation capacity payment payable in the summer and winter seasons; and
4. Eliminating payment for line losses.

I will make recommendations on these topics, as well as some general recommendations about the methodology for calculating avoided energy.

The Commission Should Reject the Proposal by DEC and DEP to Reduce the Performance Adjustment Factor from 1.2 to 1.05

Q. What is the Performance Adjustment Factor?

A. In North Carolina, QFs are compensated for their generation capacity on a performance basis. The Performance Adjustment Factor (PAF) "is a mechanism by which small QFs that are eligible for the standard rates are paid a rate that is a multiple of the utility's approved avoided capacity costs averaged over on-peak

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hours."[35] This adjustment is necessary to provide QFs the opportunity of being paid the utility's full avoided capacity costs. Regarding a PAF of 1.2, the Commission has stated that "the 1.2 PAF used by the Commission in previous cases (for QFs other than run-of-the-river hydro facilities) reflects the Commission's judgment that, if a unit is available 83 percent of the time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided costs."[36] A PAF of 1.05 corresponds to a unit being available slightly more than 95 percent of the time.

Q. What is the PAF used for renewable QFs under the current tariff?

A. The current methodology uses a PAF of 1.2.

Q. Are DEC, DEP, and DNCP proposing to reduce the PAF for renewable QFs?

A. DEC and DEP are, DNCP is not. DEC and DEP are proposing to reduce the PAF to 1.05 for non-hydro QFs.

Q. What is the rationale stated by DEC and DEP for reducing the PAF?

A. DEC and DEP Witness Snider states on page 37, line 4 of his direct testimony that "when using the peaker methodology to calculate avoided cost rates, the resource a QF is replacing is the CT. The appropriate measure of reliability for a CT peaking unit is the starting reliability. The Companies' CT fleet performs at a

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[35] Laurence D. Kirsch, Direct Testimony on behalf of the Public Staff, Docket No. E-100, Sub 140 (April 25, 2014). Page 37, Line 13.

[36] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 100 (September 29, 2005) at 22.

greater than 95% starting reliability and, as such, no PAF greater than 1.05 is warranted."

Q. Is DEC and DEP's reasoning for reducing the PAF correct?

A. It is not. Witness Snider's statement contains several errors. First, the resource the QF is replacing is not a CT. The peaker method assumes that the utility's fleet is in equilibrium and therefore "the quantitative result is not biased by the choice of one particular technology over another."[37] The only specific role for a combustion turbine in the peaker method is to estimate the avoided capacity cost ($/kW-yr) for a new unit. There is no expectation that the QF will avoid the utility procurement of a specific generator technology or type. Second, in any given hour, the QF could be displacing a peaking unit, a mid-range unit, or even a baseload unit – demonstrating that the QF's availability should be compared to the utility's entire fleet.

Witness Snider uses the performance of the company's entire CT fleet to form a comparison, but this is also flawed. Judgment as to the used and useful status of utility generators is made on a unit-by-unit basis. That some utility generators are performing well should not hide under-performing generators from scrutiny. Rather than look at the average performance, it is appropriate to look at the least-well performing company-owned generator. If that generator is considered used and useful, then a QF with similar availability should also be considered to be

[37] Laurence D. Kirsch, Direct Testimony on behalf of the Public Staff, Docket No. E-100, Sub 140 (April 25, 2014). Page 23, Line 6.

operating in a reasonable manner and therefore allowed to recover the utility's full avoided cost.

Q. Do the Companies expect each of the generators in their fleets to have availability consistent with the availability threshold associated with a 1.05 PAF?

A. No. DEC and DEP's own reporting to the Commission shows many units in its generating fleet are available considerably less than 95 percent of the time.[38] DEC and DEP's availability reporting is in line with DNCP, which has stated that "15% is a reasonable allowance for the unavailability of a base load generating unit."[39]

Q. Has DEC, DEP, or DNCP proposed reducing the PAF in the past?

A. Yes. The proposal to reduce the PAF for non-hydro renewable QFs as proposed by DEC and DEP is identical to the proposals made by DEC, DEP, and DNCP in the prior biennial avoided cost docket, Docket No. E-100, Sub 140. The Commission paraphrased the Companies' witnesses as testifying "that DEC and DEP are proposing to reduce the PAF to 1.05 to align its application better with the reliability of a natural gas CT, the unit which the QF is presumed to avoid under the peaker method."[40] The Companies use nearly identical language in this year's proposal.

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[38] Direct Testimony of Kimberly McGee for Duke Energy Carolinas, Docket No. E-7, Sub 1129, Exhibit 6, p. 15-19 (March 8, 2017), available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f1b78f5a-de84-4828-9aa0-c6446b73c1af; Supplemental Testimony of Kimberly McGee for Duke Energy Progress, Docket No. E-2, Sub 1107, Exhibit 6. Schedule 10, pp. 2-6 (Sept. 1, 2016), available at http://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=799dff1e-ce9e-4e73-a287-e53d08bc93e7.

[39] DNCP Response to SACE Request 2-14(g).

[40] E-100, Sub 140 Phase I Order at 54.

Q. What did the Commission conclude about reducing the PAF for renewable QFs in Docket No. E-100, Sub 140?

A. The Commission denied a revision to the PAF. The Commission cited its own Order from September 29, 2005, Docket E-100, Sub 100, in which the Commission ruled that "the availability of a CT is not determinative for purposes of calculating a PAF."[41] In its 2014 Order the Commission expanded on that finding of fact, noting that "the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed costs of any avoided generating unit."[42] The Commission ultimately determined in Docket No. E-100, Sub 140 that "the arguments for altering the PAF are insufficient to modify the PAF at this time."[43]

Q. What do you recommend the Commission order with respect to PAF?

A. I recommend that the Commission maintain current policy by requiring the Companies continue to use a 1.20 PAF for non-hydro renewable QFs. The availability standard implied by a 1.20 PAF better aligns with the expected availability of units in a utility fleet, and the Companies' claim that only the availability of CTs is relevant for PAF determination is as incorrect today as it was two years ago.

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[41] Order on Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2004, Docket No. E-100, Sub 100 (September 29, 2005) at 22.

[42] E-100, Sub 140 Phase I Order at 56.

[43] Id.

The Commission Should Reject the Proposal by DEC and DEP to Eliminate Capacity Payments in Certain Years

Q. What is the methodology for determining avoided generation capacity provided by renewable QFs under the current tariffs?

A. The Companies are expected to use the peaker method. The peaker method requires that a utility determine the dollar-per-kilowatt cost of building a CT and spread those costs over the expected lifetime of the peaker unit, resulting in an annualized cost. Costs associated with the CT include greenfield land acquisition, transmission interconnection costs, a reasonable contingency adder, economies of scale (but not scope), and cost estimates from publicly available sources tailored for specific conditions found in North Carolina and Virginia. Neither the expected dollar-per-kilowatt cost of the power plant the utility expects to build next nor the timing of that project are relevant to determining avoided generation capacity costs under the peaker method. DEP's Schedule PP-1, DEC's Schedule PP, and DNCP's Schedule 19-FP all employed the peaker method to determine the avoided generation capacity cost provided by a renewable QF.

Q. Are DEC and DEP proposing to deviate from the peaker methodology when calculating avoided generation capacity costs?

A. Yes. The Companies propose making no avoided generation capacity payment to a QF until "the first year in which DEC and DEP show an actual need for incremental capacity."[44] Company Witness Snider states on Page 34, Line 20 that

[44] Duke Energy Carolinas and Duke Energy Progress Joint Initial Statements and Exhibits, Docket E-100, Sub 140 (November 15, 2016). Page 8.

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"the first capacity need for both Companies occurs in the 2022-2023 timeframe" in accordance with the Companies' 2016 IRPs.

Q. Is it appropriate to refuse an avoided generation capacity payment in the near-term years when applying the peaker method to calculate avoided generation capacity costs?

A. It is not. The rationale to use the dollar-per-kilowatt cost of a CT and making a capacity payment in every year are inextricably linked. Indeed, the peaker method's use of the cost of a CT (and not the cost of the next generator the utility expects to build) results from the assumption that the utility's generating system is operating at equilibrium and that generation capacity payments will be made for all years in which the QF is in service.

Q. Has DEC or DEP proposed revising the avoided generation capacity cost methodology in the past?

A. Yes. In the most recent prior docket, Docket No. E-100, Sub 140, DEC and DEP proposed "to include zeroes in their avoided capacity cost calculations during the early years of the planning horizon."[45]

Q. Are the key concerns expressed two years ago about this proposed change to the avoided generation capacity cost methodology still applicable?

A. Yes, they are. On behalf of NCSEA, Witness R. T. Beach observed that the buildout of traditional large-scale utility capacity is lumpy in character, and therefore utilities often build far more generation capacity than is required in the subsequent year, resulting in ratepayers paying the utility for significantly more

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[45] E-100, Sub 140 Phase I Order at 32.

generation capacity than is needed until "demand 'catches up' to the last major additions."[46] Witness J. Rick Hornby, on behalf of TASC, testified that this methodological change would perversely incent utilities to over-plan and over-build in order to avoid paying avoided generation capacity costs to QFs.[47] Public Staff Witness John Hinton was explicit about the theoretical underpinnings of the peaker method: "including zeroes in the calculation of avoided capacity costs or paying capacity payments only when reserve margins are low does not comport with that theory."[48] Each of these concerns are as applicable today as they were two years ago.

Q. What did the Commission conclude about altering the avoided generation capacity cost methodology to allow for the inclusion of zeros in some years in Docket No. E-100, Sub 140?

A. The Commission rejected this methodological change. In the Order on the 2014 avoided cost proceeding, the Commission wrote: "The Commission determines that it should not authorize as a generic principle that the avoided cost rate should be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into."[49] Further, the Commission pointed out

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[46] Id., at page 33.

[47] Id., at page 34.

[48] John R. Hinton, Additional Testimony on behalf of the Public Staff, Docket No. E-100, Sub 140 (May 30, 2014). Page 7, Line 6.

[49] E-100, Sub 140 Phase I Order at 35.

utility witnesses' concession that "the cost of that future needed capacity is not changed by the fact that a utility has sufficient capacity in the very near term."[50]

Q. What do you recommend the Commission order with respect to DEC and DEP's proposed inclusion of zeros in some years when calculating avoided generation capacity cost?

A. I recommend that the Commission reject the proposed changes and instead require that DEC and DEP calculate the avoided generation capacity cost using the same peaker method used in the prior docket, Docket No. E-100, Sub 140.

Q. Is DNCP proposing to deviate from the peaker methodology when calculating avoided generation capacity costs?

A. Yes. The Company proposes the elimination of avoided generation capacity payments altogether, stating that "the addition of QF solar resources in DNCP's North Carolina service area will not allow the Company to defer or avoid capacity related costs" (Petrie, Page 23, Line 10).

Q. What explanation does DNCP provide for eliminating the avoided generation capacity cost payment altogether?

A. Company Witness Petrie states in his direct testimony that, based on DNCP's 2016 IRP, the Company has "a need for capacity starting in 2024," but that "additional solar QFs are not an effective substitute for new dispatchable generation, such as a combustion turbine ("CT") facility."[51]

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[50] Id.

[51] Direct Testimony of Bruce E. Petrie, Page 14, Line 10 and Page 15, Lines 10-12.

Q. Is Witness Petrie correct in implying that solar QFs offer limited or no ability to defer or avoid capacity related costs?

A. No. DNCP must own or purchase generation capacity for both summer and winter peak, and generation capacity – including solar generation capacity – is valuable in both seasons. Because many fossil-fueled generators have a higher generating capacity during winter months, DNCP's existing generation assets may still be capable of meeting a higher winter peak and not a corresponding, slightly smaller summer peak. Furthermore, DNCP is located within PJM, a summer-peaking system. The PJM wholesale generation capacity market has a surplus of capacity during winter months but a market demand for summertime capacity. For these reasons, even if the generation capacity value solar QF generation provides in wintertime is assumed to be slight, solar QFs still offer DNCP an ability to defer or avoid capacity related costs, as well as sell additional surplus generation capacity in PJM's Reliability Pricing Model (RPM) capacity market.

Q. Does the theory behind the peaker method envision a situation where the generating profile of the QF is not aligned with the generating profile of the utility's planned capacity addition?

A. It does. The peaker method is appropriate regardless of the technology of the QF or the details of the utility's future resource plan because the peaker method does not require that the QF have operating properties that align with the utility's planned capacity addition in any way. The peaker method's ability to calculate avoided generation capacity cost regardless of the specifics of the utility's capacity expansion plan is an important feature.

Q. Witness Petrie states that solar PV's capacity value within PJM is quite low. Is he correct?

A. On page 20, line 14 of his direct testimony, Witness Petrie states without citation that "PJM issued training materials that suggested an acceptable offer for a 100 MW nameplate solar facility would be in the range of 0 to 20 MW of firm capacity."[52] PJM Manual 21, "Rules and Procedures for Determination of Generation Capacity," outlines the procedures for calculating the capacity value of solar.[53] PJM publishes the class average capacity value of solar: 38 percent.[54] This value is considerably more than the range of values Witness Petrie states.

Q. Has DNCP proposed adjustments to the avoided capacity cost recovery methodology in the past?

A. Yes. This year's proposal is an extension of DNCP's proposal from two years ago, in which DNCP testified that "avoided capacity costs are zero in the first three years of the 15 years because DNCP, as part of the generation planning process and to maintain reliable service for its customers, will have already planned for and procured its projected capacity needs for at least the next three years at any time."[55]

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[52] Direct Testimony of Bruce E. Petrie, Page 20, Lines 13-15.

[53] PJM, "PJM Manual 21, Rules and Procedures for Determination of Generating Capability." Revision 12, Effective Date January 1, 2017. Page 20. PJM confusingly refers to capacity value in this context as "capacity factor" because the PJM methodology for determining capacity value entails calculating the resource's capacity factor during summer peak hours.

[54] PJM, "Class Average Capacity Factors for Wind and Solar Capacity Resources," January 1, 2017. Available at: http://www.pjm.com/~/media/planning/res-adeq/wind-and-solar-class-average-capacity-factors.ashx.

[55] E-100, Sub 140 Phase I Order at 33.

Q. What did the Commission conclude about including zeroes as the avoided cost rate in Docket E-100, Sub 140?

A. In the Order on the 2014 avoided cost proceeding, the Commission wrote "[t]he Commission determines that it should not authorize as a generic principle that the avoided cost rate should be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into."[56] The Commission added that "including zeroes for the first three years in the calculation of capacity rates lowers the avoided cost rate for the entire 15-year period. Thus, depending on the utility's actual needs over the term of the PPA, the resulting avoided cost rates may not equal the full cost of a CT…as intended by the peaker method."[57]

Additionally, the Commission determined that FERC's ruling in Ketchikan does not apply in North Carolina's proceedings, as it was evidence of the FERC order being a result of "the unique facts of the case before it," thus disallowing the use of the Ketchikan ruling as support for DNCP's proposal.[58]

Q. What do you recommend the Commission order with respect to allowing zeroes in the avoided cost rate?

A. I recommend that the Commission reject DNCP's request to deviate from the peaker method by including zeroes in the avoided generation cost calculation. I further recommend that the Commission maintain its ruling from the previous avoided cost rate docket and require DNCP to employ the peaker method.

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[56] Id., at page 35.

[57] Id.

[58] Id.

The Commission Should Adjust the Proposal by DEC and DEP to Change the Fraction of Avoided Generation Capacity Payment Payable in the Summer and Winter Seasons

Q. Are DEC and DEP proposing a revision to the split of capacity hours between summer and winter seasons?

A. Yes. According to Witness Snider, the Companies incorporated a new weighting of summer and winter capacity hours, placing an 80 percent weighting on the winter hours and a 20 percent weighting on the summer hours.[59] In previous biennial proceedings, the weighting of seasonal hours has been exactly the opposite, with 80 percent of the annual avoided capacity payment paid for QF performance during summertime hours and 20 percent of the avoided capacity cost applied to performance during winter hours.

Q. How did the Companies determine to make a change to the weighting of seasonal peak hours?

A. The Companies commissioned two resource adequacy studies, one each for Duke Energy Carolinas and Duke Energy Progress, which were prepared by Astrape Consulting in 2016 ("Astrape Report").[60] The resource adequacy studies reviewed Loss of Load Expectation (LOLE) in 2019.

Q. Please describe LOLE in greater detail.

A. As described in the Astrape report, "Loss of Load Expectation (LOLE) is defined in events per year and is calculated for each of the 180 load cases and weighted

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[59] DEC and DEP Joint Testimony in Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2016, Witness Glen A. Snider, Docket E-100, Sub 148 (February 21, 2017). Pages 30-31.

[60] Astrape Consulting, Duke Energy Carolinas (DEC) 2016 Resource Adequacy Study, and Astrape Consulting, Duke Energy Progress (DEP) 20216 Resource Adequacy Study.

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based on probability. When counting LOLE events, only one event is counted per day even if an event occurs early in the day and then again later in the day. Across the industry, the traditional 1 day in 10 year standard is defined as 0.1 LOLE."[61] Effectively, LOLE is a method of translating reliability standards expressed in long-term characterizations into annual loss of load probability allowances. It is an industry standard method for determining reliability on the system.

Q. **What did the Astrape study determine?**

A. One of the study's findings was that at a 0.1 LOLE, 80 percent of the days with expected loss of load would be expected to occur during the winter season.

Q. **Do you have any concerns with the Astrape study itself?**

A. I do. I am concerned that the study overemphasizes the atypical recent weather experienced during the 2014 and 2015 winters. Despite the fact that "36 historical weather years (1980 – 2015) were developed," the analysis was "based on the last five years of historical weather and load."[62] The study states that this "ensured the cold temperatures and high winter loads experienced during the 2014 and 2015 winter periods were included in the load development."[63] This is a puzzling statement, because including all 36 years of historical weather data the study team already had would have both ensured the inclusion of the Polar Vortex years without overly emphasizing them, something including only five years of data

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[61] DEC Report, Page 30; DEP Report, Page 30.

[62] DEC Report, Page 12; DEP Report, Page 12.

[63] Id.

did. Overemphasizing the unusually cold 2014 and 2015 Polar Vortex winters overstates the likelihood that reliability challenges are more likely to occur in wintertime rather than summertime, as has been the case historically.

Q. How does Duke apply this finding to the weighing of summertime and wintertime capacity values?

A. Duke applies the LOLE study finding (80 percent wintertime) to its capacity weighing, for all future years.

Q. Is this a reasonable approach?

A. It is not. The Astrape study seeks to show an increased importance of ensuring wintertime reliability. However, Duke is applying a narrow finding far too broadly. The study is solely for 2019, but Duke applies the results for seasonal capacity value allocation for every year of the long-term contract.

Furthermore, the study assumes Duke's 2016 IRP values for both wintertime energy efficiency and wintertime demand response, which fails to account for potential future shifts in these programs to focus specifically on wintertime peaks. For example, DEC's 2016 IRP shows 1,119 MW of summertime DSM capacity, but only 513 MW of wintertime DSM capacity.[64] These values fail to reflect any future investments or changes Duke will make to its DR and EE programs to focus on meeting wintertime peak needs in addition to summertime peaks.

[64] Duke Energy Carolinas 2016 Integrated Resource Plan, Docket No. E-100, Sub 147 (Sept. 1, 2016), Tables 8-C and 8-D.

These values also fail to reflect any opportunities DEC or DEP may have in the near future to procure additional firm wintertime capacity in bilateral agreements. For example, DEP has approximately one dozen interconnection facilities with PJM.[65] Because PJM is summer peaking, there may be an opportunity to obtain low cost wintertime-only capacity from PJM.

The Astrape study shows that, beginning in 2019, wintertime capacity is more valuable than it was two years ago. However, it doesn't tell us anything about the seasonal capacity value split for 2017 or 2018, and furthermore it overstates the wintertime capacity value beginning in 2019 for the reasons I discussed above. Beginning in 2019, the pendulum may swing from 20 percent wintertime capacity to something more significant. However, the Astrape study overstates that adjustment.

Q. What do you recommend the Commission order with respect to the apportionment of DEC and DEP summertime and wintertime generation capacity payments in the avoided cost rate?

A. I recommend that the Commission order DEC and DEP to weigh summertime capacity at 80 percent for the years 2017 and 2018, because the Astrape study does not show results until 2019. I also recommend the Commission require Duke to refine its seasonal weights for Year 2019 and beyond to account for the study's exclusion of weather data and flawed assumption that Duke won't respond to the report with the procurement of additional wintertime capacity resources. If Duke

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[65] PJM Interconnection, L.L.C. ad Duke Energy Progress, Inc., "Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress, Inc.," December 31, 2014. Appendix B. Available at http://www.pjm.com/media/documents/merged-tariffs/progress-joa.pdf.

cannot make the necessary adjustments in time for this docket's resolution, the Commission should use its judgment in determining a capacity weight for years 2019 and later, between the 80/20 summertime/wintertime split used now and DEC and DEP's proposed 20/80 split. This intermediate value would acknowledge the Astrape study's findings, but also account for the fact that Astrape has overemphasized recent weather events, that Duke may reform its EE and DR programs to procure more wintertime capacity, and that low-cost firm wintertime-only bilateral capacity agreements are possible with neighboring balancing authorities.

The Commission Should Reject DNCP's Proposal to Eliminate Payment for Avoided Line Losses

Q. Are line loss avoidance calculations included in the avoided cost calculation methodologies under the current tariffs?

A. DEP's Schedule PP-1, DEC's Schedule PP, and DNCP's Schedule 19-FP all include adjustments for avoided line losses.

Q. Are DEC, DEP, and DNCP proposing to change the avoided cost calculation methodology with respect to line losses?

A. DNCP is proposing to eliminate all avoided costs associated with line loss. DEC and DEP leave their current method unchanged.

Q. What is DNCP's justification for eliminating line loss avoidance in its avoided cost calculation methodology?

A. DNCP Witness J. Scott Gaskill states in his direct testimony that "losses are generally only avoided when the substation load exceeds the local distribution generation on a substation bus" and that "of the 33 transformers, 11 show a predominantly constant backflow of power, indicating that the energy delivered from the distributed generation connected at these substations exceeds the load".[66]

Q. Do you agree with Witness Gaskill's assessment about the lack of line loss avoidance potential on DNCP's system?

A. I do not. I believe that Witness Gaskill is mischaracterizing the impact of backflow on line losses, both in his text and in Exhibit JSG-1. Witness Gaskill claims that any backflow from the substation indicates zero avoided line loss. It is true that increasing backflow from a substation that is already backflowing will not necessarily result in line loss avoidance at that specific time. However, to the extent that a substation receives positive flow from the transmission system at any half-hour, an operating local distribution generator will avoid transmission line losses at that time.[67] The QF that "flips" the substation from traditional flow to backflow in each half-hour interval will, in fact, reduce transmission line losses over that half-hour. For example, if a substation has 8 MW of load at a given hour and has a QF producing at 10 MW at that hour, there will be approximately 2 MW of backflow. In this situation, despite Witness Gaskill's claims, there is a line loss reduction because the transmission grid observes a net reduction of 8 MW of total demand at that hour. As long as there are hours in a year when the transmission grid sees a net reduction of total demand, there will be line loss avoidance.

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[66] Direct Testimony of J. Scott Gaskill, Page 20, Line 20 and Page 21, Line 13.

[67] For solar QFs, this benefit obviously only holds true for time intervals during daylight.

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Q. Witness Gaskill claims on Page 21, Line 14 that 11 of the 33 transformers show a "predominantly constant backflow of power." How do you respond to that?

A. I disagree with Witness Gaskill's assessment, as my analysis of the half-hourly data associated with the 33 transformers detailed in Exhibit JSG-1 demonstrates something quite different.[68] I analyzed the raw data associated with all 33 transformers. First, I discarded consecutive half-hours of 0.000 MW flow measurements, because those measurements almost certainly represent sensor failure and not perfectly balanced power flow in that portion of the distribution circuit. Because our focus is on the impact of future QFs and because a PV QF generator may have interconnected in between the data collection start date in late 2015 and the conclusion in late 2016, I focused my analysis only on the period for which each given substation demonstrates backflow. Yet, even after focusing on the period of each data set most likely to demonstrate backflow, only Whitakers TX#2 had a majority of its half-hours presenting backflow. Each of the other 10 substations labeled "negative" in JSG-1 had positive flow during most of their operating hours. The median so-called "negative" substation had positive flow during 69 percent of the half-hours. The median "neutral" substation had positive flow 97 percent of the time, and the median "positive" substation had positive flow 100 percent of the time. Witness Gaskill's data from Exhibit JSG-1 demonstrates exactly the opposite of his claim: Line loss avoidance would be expected to occur with an additional PV QF added to 32 of DNCP's 33 substations detailed in JSG-1.

[68] DNCP Response to NCSEA Request 1-8(e) and 1-8(f), Attachments.

Q. Please describe your concerns associated with DNCP's proposal to eliminate line loss avoidance in its avoided cost calculations.

A. Additional PV QF capacity on at least 32 of the 33 substations in DNCP's North Carolina territory would result in incremental avoided line losses. Therefore, eliminating the line loss avoidance portion of the avoided cost calculation is inappropriate.

Q. Has DEC, DEP, or DNCP proposed eliminating the line loss avoidance calculation for renewable QFs in the past?

A. Not to my knowledge.

Q. What do you recommend the Commission order with respect to the inclusion of line loss avoidance in avoided cost calculation methodology?

A. I recommend that the Commission require DNCP to include line loss avoidance in its calculations. For more than half of DNCP's substations in North Carolina, additional line loss avoidance could occur over 96 percent of the time with additional QFs. However, there are some substations with some backflow today, and therefore there are a reduced set of hours for which transmission line loss can be avoided. The Commission should require DNCP to calculate line loss avoidance with sufficient granularity to compensate renewable QFs for the value those QFs provide with respect to line loss avoidance. Should DNCP lack the ability to study line loss avoidance with sufficient granularity, it should continue using the 3 percent line loss avoidance value.

The Commission Should Require DNCP to Rerun its Avoided Energy Cost Model After Correcting the Availability Input

Q. How did the companies calculate the avoided energy costs associated with solar PV QFs?

A. The Companies use security constrained hourly dispatch modeling to forecast which generating units will be operating each hour over the period of the analysis. The same model is then run a second time, but this time it includes an additional 100 MW generator that operates in all hours and has zero marginal cost. The difference in total annual cost between the two model runs represents the annual avoided energy cost. The avoided energy cost is primarily associated with avoided fuel consumption, but it also includes other variable costs such as variable operations and maintenance costs and emissions allowances. Because the utilities model (and actually dispatch) units from low-cost to high, this method appropriately recognizes that the QF will displace the most expensive unit operating at that hour, subject to reliability and operations constraints.

Q. Do you have any concerns with the way the utilities modeled avoided energy?

A. Yes, I have a concern with DNCP's approach. DNCP modeled the "with QF" case with a "100-MW unit; must-run; 85% availability; and zero energy cost" (DNCP Witness Petrie, Page 7, Line 4). I have several concerns related to the 85 percent availability assumption for the QF unit. The Company rationale is that "since no generator is expected to achieve 100% availability, the 85% availability is representative of a base load unit. In other words, the 15% is a reasonable

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allowance for the unavailability of a base load generating unit. The 15% unavailability is spread evenly across all hours of the year."[69] My first concern is that DNCP modeled solar QF outages using anecdotal experience with base load generating units, rather than attempt to make modeling decisions based on the expected performance of QFs in DNCP's territory. My second concern relates to the avoided cost calculations themselves. By modeling a QF that only operates on 85 percent of the hours of the year, the DNCP calculated total annual avoided energy cost will only be 85 percent of the total possible annual avoided energy cost. If DNCP divides the resulting savings by the total MWh the QF operates in the simulation, the $/MWh result will be appropriate. If, however, DNCP divided the total dollars of savings by 876,000 MWh,[70] DNCP's avoided energy rate will be approximately 15 percent too low.

Q. How could DNCP improve its avoided energy cost modeling?

A. The purpose of the avoided energy modeling exercise is to determine the total avoided energy value that a QF could provide, not to predict how much avoided energy the QF will avoid. Rather than subject the analysis to unnecessary randomness and error associated with non-QF-related outage simulations or to the risk of incorrectly calculating the average avoided energy costs, DNCP could instead simply model the QF unit with 100 percent availability. This would allow the model to correctly count the value of QF generation on each and every hour of

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[69] DNCP Response to SACE Request 2-14(g).

[70] With 8,760 hours in a year and 100 MW, the maximum energy the 100 MW unit could create in a year is 876,000 MWh.

the year and ensure that the Company's analysis of the model results does not inadvertently only pay QFs for 85 percent of their avoided cost.

Q. What do you recommend the Commission order with respect to DNCP's avoided energy cost calculation methodology?

A. The Commission should require DNCP to rerun their avoided energy cost model "with QF" case with a 100 MW unit; must-run; 100 percent availability; and zero energy cost unit.

6. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I recommend the Commission maintain a number of current standard offer contract polices, including

1. retaining 5 MW as the threshold for renewable QF eligibility for standard offer contracts;
2. retaining the option of a 15-year standard offer contract; and
3. requiring the utilities to include fixed rates for all portions of the standard offer contract.

The utilities' proposed changes would result in added burdens for potential QFs without providing cost savings for the utilities. I recommend the Commission reject or alter a number of utility proposals related to avoided cost calculations. I recommend that the Commission

1. maintain the current 1.20 PAF;

2. maintain the peaker methodology, including the requirement of paying avoided capacity cost payments in all years;
3. reject Duke's proposal for revising the capacity payment split among summertime and wintertime hours, instead assigning 80 percent summer for 2017 and 2018, and a recalculated percent for all years thereafter based on corrections to Duke's study;
4. require Dominion to continue compensating for avoided line loss; and
5. require Dominion to model its avoided energy costs with a 100 percent available resource.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MS. BOWEN:

Q Dr. Vitolo, did you prepare a summary of your testimony?

A I did.

Q Would you please give your summary to the Commission?

A Mr. Chairman and Members of the Commission, my name is Thomas Vitolo. I am a Senior Associate with Synapse Energy Economics at 485 Massachusetts Avenue, Suite 2, Cambridge Massachusetts. I have a PhD in systems engineering from Boston University; a master's in financial and industrial mathematics from Dublin City University, Ireland; and bachelor's degrees in applied mathematics, computer science, and economics from North Carolina State University; as such I spent this March looking forward to next year. (Laughter) I also have more than nine years of professional experience as a consultant, researcher, and analyst.

Since joining Synapse in 2011, I have focused on university, excuse me, on utility resource planning, variable resource integration, avoided costs, and other issues that typically involve statistical analysis, computer simulation modeling, and stochastic processes. I have filed testimony or reviewed utility filings in 24 states and two territories, primarily by evaluating numerical analysis, modeling, and decision strategies of resource plans and certificates of public convenience and necessity applications.

I thank the Commission for the opportunity to participate in this important proceeding. I am here today to testify on behalf of the Southern Alliance for Clean Energy. In my testimony I have addressed a number of the proposals that Duke Energy Carolinas, Duke Energy Progress, and Dominion North Carolina Power have made in the course of this proceeding. My evaluation determined that the Utilities' proposals do not comply with PURPA, or with FERC's regulations and orders implementing PURPA; they are inconsistent with this Commission's findings in prior biennial avoided cost proceedings; and they lack a sound technical basis in light of the established peaker method and my experience with these and similar issues.

Based on my analysis, I first recommend that the Commission reject many of the Utilities' proposed changes to the standard offer. The Utilities have not justified their proposals to reduce the eligibility threshold to 1 megawatt, shorten the contract duration to 10 years, or to update the avoided cost rates every two years for either small or large QFs. The Utilities should retain the existing standard offer avoided cost contract terms and conditions, specifically the 5 megawatt threshold for standard offer contract eligibility and the availability of 15-year levelized standard offer rates that are fixed for the duration of the contract. In the previous biennial cost proceeding, the Commission determined that these contract terms appropriately balanced the interests of qualifying facilities and ratepayers. Contrary to the Utilities' assertions in this proceeding, these terms and conditions continue to appropriately encourage the development of smaller QFs up to 5 megawatts, while ensuring that ratepayers are held harmless. I conclude that the Utilities' proposed changes would result in added burdens for potential QFs without providing cost savings for the Utilities and their ratepayers.

With respect to avoided cost calculations, the Utilities have made several errors and faulty assumptions in the process of calculating their avoided energy and avoided capacity rates, flaws in Duke's calculations include use of a combustion turbine plant availability (or average availability of all units on the system) for determining the PAF, as previously rejected by this Commission; Duke's proposal to assign no value to avoided capacity in all years prior to Duke's first stated capacity need, which is inconsistent with the Commission's approved peaker method and its theoretical underpinnings; and Duke's premature shift to a winter-peaking paradigm based on a report that overemphasizes rare weather events and assumes DEC and DEP won't seek any additional wintertime capacity through their Energy Efficiency programs, Demand Response programs, or bilaterally, thereby artificially depressing the capacity value of solar. Dominion's avoided cost rates suffer from their own flaws, including the elimination of line loss avoidance based on overstated impacts of backfeeding and resulting impacts on avoided line losses; Dominion's methodology in calculating its avoided energy rates that assumes every solar installation is broken more than one day a week; and Dominion's decision not to include avoided capacity rates despite its participation in PJM's RPM, a wholesale generation capacity marketplace.

I recommend the Commission maintain the current 1.20 Performance Adjustment Factor; maintain the peaker method, including the requirement of paying avoided capacity payments in all years; reject DEC and DEP's capacity payment split proposal among summertime and wintertime hours for 2017, 2018, and until such time that their study has been correct; require Dominion to model its avoided energy costs with a 100 percent available resource; and require Dominion to continue compensating for avoided line loss and avoided capacity.

In conclusion, I respectfully urge the Commission to reject the Utilities' proposals and avoided cost calculation methodologies that I have identified in my testimony, as those suggested alterations do not protect ratepayers but will inhibit the development of independent power producers in contravention of PURPA. Thank you.

MS. BOWEN: Thank you, Dr. Vitolo. The witness is now available for cross examination.

CHAIRMAN FINLEY: Do Intervenors have questions for Dr. Vitolo?

(No response.)

CHAIRMAN FINLEY: Companies?

MS. FENTRESS: Thank you.

CROSS EXAMINATION

BY MS. FENTRESS:

Q Good afternoon, Dr. Vitolo. My name is Kendrick Fentress. I'm an attorney with Duke Energy. How are you?

A Very well. How are you?

Q I'm good. Thank you. Dr. Vitolo, I think you would agree with me that the Commission's role in implementing PURPA in North Carolina is to strike a balance between encouraging QF development on the one hand and protecting customers from the

risk of overpayment of those rates on the other hand. Would you agree with that?
A Subject to the federal laws, yes.
Q And would you also agree that in striking that balance the Commission is able to look at current economic and regulatory circumstances that are present in the state when they review PURPA considerations, PURPA implementation rather?
A Sure.
Q And turning to page 6 of your direct testimony, you give an overview of the previous avoided cost proceeding; is that correct?
A Did you have lines?
Q I'm so sorry, yes, it's lines 9 through 15.
A Yes.
Q And in your testimony on line 14 you give the date that the Commission's Order setting avoided cost input parameters was issued and that date is December 31st; is that correct?
A You said page 14?
Q I'm sorry, page 6, line 14.
A Oh, I'm sorry.
Q That's quite all right.
A Yes.

Q And that Order has been stipulated into the record, but would you agree with me that the facts and conclusions in that Order were a -- resulted from an evidentiary hearing in that docket that took place in July 2014?
A You're referring to E-100, Sub 140?
Q I am --
A Yes.
Q -- phase I.
A Yes.
Q The Phase I. Yes.
A Yes.
Q And so you would agree with me July 2014 was almost three years ago?
A Yes.
Q And as I read your testimony today, you -- well, let me back up. You've read the Companies' testimony in this docket; is that correct?
A Yes.
Q And as I went through your testimony I did not see any citation to Company Witness Holeman's testimony on the operational challenges that the Companies are facing; is that correct; there's not a cite to Witness Holeman's testimony?

A That's right.
Q And so your testimony does not directly address the operational challenges that the Companies are facing at this time, or the testimony of Witness Holeman?
A I didn't see any language in Witness Holeman's testimony, maybe I missed it, that quantified the costs of those alleged challenges. And since I was interested in avoided costs, without quantifying those costs it was difficult for me to incorporate that testimony when looking for actual avoided costs.
Q And I would -- thank you. And I would also note that I looked at your testimony and I did not see a reference to the risk of overpayment that Public Staff Witness Hinton identified as well.
A Nor a risk of underpayment.
Q That's correct. And so looking at your summary, if I could turn to the second page of your summary, line 7.
A I'm sorry, what -- you saw on page?
Q It's page 2 of your summary, line 7.
A I'm sorry. Yes.
Q And on line 7 you say, *The utilities should*

retain the existing standard offer avoided cost contract terms and conditions. Do you see where I am?
A I do see where you are.
Q *Including the 5 megawatt threshold*?
A I -- this says including. I said *specifically the 5 megawatt threshold* in my testimony.
Q Certainly. *And the availability of the 15-year standard offer.*
A Yes, ma'am.
Q I think you also indicated in your summary, go to lines 18 through 17, you recommended that the Commission not alter its previous decision to assign no value, I'm sorry, to decline to accept *Duke's proposal to assign no value to avoided capacity in all years prior to Duke's first stated capacity need.*
A In accordance with the peaker method; that's right.
Q And I also see that you urge the Commission to maintain the current 1.20 Performance Adjustment Factor; is that correct?
A That's right.
Q So just in general if I've summarized it, would

you agree with me that a fair assessment of your testimony is that you would like for the Commission to maintain the status quo that it set back in Sub 140?

A No, I don't think that's a complete characterization. I address a subset of all of the proposed changes that Duke and Dominion have proposed so I am not going to comment on other changes, some of which I'm sure are quite reasonable but outside of my area of expertise, or within my area of expertise, and I thought were perfectly good changes. So I spoke to a subset of all of the proposed changes.

Q Could you identify what some of the perfectly good changes might be?

A Well, I will say that there were some changes regarding the LEOs that seemed reasonable to me. But because I am not a lawyer or a financier - lawyers and financiers may have other opinions on that - but to me that seemed perfectly reasonable.

Q Thank you. Was there anything else?

A I'd have to go back and look.

Q But with respect to the proposed modifications to the standard offer - the eligibility, the length of the contract, the Performance Adjustment Factor, the inclusion of capacity value in years where capacity value is not needed by the Company - you have urged the Commission to maintain its prior rulings in Sub 140; is that correct?

A Yes, I believe that's correct.

Q And you agree that those rulings did result from an evidentiary hearing held three years ago?

A I do. But it's not clear to me that with regard to those issues that the details have changed at all.

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

CHAIRMAN FINLEY: Dominion?

MS. KELLS: Yes.

CROSS EXAMINATION

BY MS. KELLS:

Q Good morning, Andrea Kells with Dominion representing Dominion. How are you?

A Very well. How are you?

CHAIRMAN FINLEY: Pull the microphone up, Ms. Kells, please.

MS. KELLS: Oh, yes.

BY MS. KELLS:

Q I have a few questions for you about line loss.

A Yes, ma'am.

Q And hearing your background, you've got a lot more math in your background than I do so please bear with me. You address Dominion's line loss proposal in your testimony, correct?

A Yes.

Q And just before we get into that, you would agree with me, would you, that the purpose of the line loss adder that's been in place is to compensate QFs for line losses that their facilities allow utilities to avoid; is that right?

A Correct.

Q That's a concept. And you're familiar -- are you familiar that FERC has a rule in place that allows rates for QF purchases to reflect avoided line losses?

A Can you point to the ruling?

Q Sure I can. Hang on. This is an exhibit. I've got it. This is Section 292.304(e)(4). May I approach?

CHAIRMAN FINLEY: Yes.

BY MS. KELLS:

Q And would you agree that that subsection reads, if you'll go back up to (e) *Factors affecting rates for purchases.* Are you there with me?

A Yes, ma'am.

Q It says, *In determining avoided costs, the following factors shall, to the extent practicable, be taken into account.* And then if you go down to the (4), it says, *The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.*

MR. STEIN: Counsel, could you direct us to where we are, sorry, in the regulation?

MS. KELLS: Sure. I'm sorry. It's 292.304(e)(4).

MR. STEIN: (e)(4), okay. Thank you.

MS. KELLS: You're welcome.

BY MS. KELLS:

Q Did I read that correctly?

A Yes, ma'am.
Q So would you agree that, according to FERC, paying for line loss is appropriate where the Utility avoids line loss costs it would have occurred but for the QF being at that location?
A Yes.
Q Okay. And would you also agree with me that the reason distributed solar generation like we're talking about today has the potential to avoid line loss is that the energy generated by these QFs can at least in part meet the requirements of the load at a particular location so that the electricity doesn't have to go elsewhere on the system?
A That is one way in which solar QFs can avoid line losses, yes.
Q Okay. You recognize in your testimony that there is a phenomenon that we've been calling "backflow", correct?
A Yes.
Q One example is at page 40, lines 7 through 9 of your testimony where you say, *it's true increasing backflow from a substation already backflowing will not necessarily result in line*

loss avoidance at that time.
A That's right. It depends on the details of the substation and the flow on the transmission grid.
Q Okay. So would you agree with me that when we use this word "backflow" we're describing a situation where the amount of generation at a specific location at a certain time exceeds the load at that location and so it backflows back onto the substation?
A I think we need to be a little bit more careful with the language. When we say "location", I'm not sure exactly what you mean. Surely you don't mean at that site but some surrounding area.
Q Right.
A So it depends on what that area is.
Q Right.
A If you could be more clear, that would be helpful.
Q Why don't you explain -- would you like to tell me what you think a backflow is and then we'll be on the same page?
A So I think -- so I was actually sort of borrowing from Witness Gaskill's language, and my understanding is he was referring to each of 33

substations owned or operated by Dominion in North Carolina.

Q Okay.

A And, in fact, his exhibit included backflow from all 33. And in this context the question is how often is the net flow from the grid going into the substation or coming from the substation back to the grid. On times when energy is flowing into the substation if a QF is generating that means that less energy needed to flow into the substation and that means that we're avoiding losses on the grid at that moment, and of the 33 substations only one is backflowing more than half of the time. The other 32 are backflowing less than half of the time ranging from 0 percent backflow to -- to I don't recall 30 or 40 percent backflow. The majority, however, have very little backflow any hour of the day. This is day or night. The ones that do have backflow tend to have backflow during some hours of the day, certainly not at all at night.

Q Right. I'm glad you mentioned that because I was going to ask you about Mr. Gaskill's analysis and then -- so you reviewed that obviously --

A Yes, ma'am.

Q -- and you did your own analysis that you discussed just now and in your testimony of the line loss situation at these 33 transformers?

A I did. Rather than look at the charts, which have very thick lines representing approximately 17,000 half hour intervals of data, I looked at the numbers themselves. I found the charts weren't helpful in understanding the amount of backflow because the lines are very thick, certainly not thin enough to represent to 17,000 different data points on one piece of paper. And so by looking at the actual data it became much clearer that there is, in fact, very little backflow on most of those substations indicating that additional QF generation would, in fact, reduce line losses.

Q Okay. So do you recall that in discovery you provided to Dominion the workpapers for your analysis?

A Yes, ma'am.

Q Which were in turn based on data that Dominion provided pursuant to an NCSEA discovery request?

A I believe that was the discovery request, yes.

Q I'm going to -- I'd like to talk a little bit about an excerpt of your analysis --
A Sure.
Q -- because as you said there's a lot of data there. So I'm going to pass around an exhibit.

MS. KELLS: And, Mr. Chairman, can we mark this as DNCP Vitolo Cross Exhibit 1?

CHAIRMAN FINLEY: It shall be so marked.

DNCP Vitolo Cross Exhibit 1
(Identified)

BY MS. KELLS:
Q And while that's being handed out, Dr. Vitolo, this -- I'll represent to you this exhibit is derived from your response to Dominion's discovery request and so -- that we spoke of just a moment ago ánd so obviously it's -- you're welcome to go back and check it. The first page has got the word "Info" at the top, and so this is the first -- it's the tab that you had labeled "Info" in your response document and it's sort of a summary of just what's going on here, the docket number and the source of the data; is that right?
A Yes, ma'am.

Q And then, if you'll flip to the second page, this corresponds to the tab in your analysis labeled "Summary". And so I've maintained the categories on the left-hand side and then you had included summary information for each of the 33 transformers.
A And this is just one of the 33.
Q This is just one --
A Yes, ma'am.
Q -- because we've been here a long time.
A And perhaps because some of the other ones tell a different story.
Q They may but for illustrative purposes --
A Understood.
Q -- I'm going to ask you about this one if that's all right?
A Yes, ma'am.
Q So just to get our -- and then the third and fourth pages of this exhibit are taken from a very large voluminous tab in your -- that you just spoke of with a lot of data -- and so what we're looking at there is Dominion had provided data for each half hour of everyday between September 1, 2015, and September 7, 2016, along

with the flow data at each location.

A That's mostly correct. For some of the substations, they didn't quite cover that date range and there were a number of substations which were reporting 0.00000 for multiple half hour increments consecutively which is likely to be a sensor error and not actually a load of exactly zero on a substation. So we want to be a little bit careful about the data.

Q Sure and we'll -- I'll mention the zeros then in just a moment.

A Great.

Q Yes, I recognize that.

A (Coughs) Excuse me.

Q The third page and fourth pages are - the third page is an excerpt from your data for this one transformer, I was calling it Parmele (Par-mel) but its Parmele (Par-me-le) for one day in January or most of one day in January, and then the fourth page is an except of that half hour data for the same transformer for one day in July. Do you see that?

A Yes. It's not my data but, yes, I see it.

Q Right. You see it on the page, okay. And so

let's look back -- and so let's stay on page 3 for just a moment. So if you look at the line number on the -- row number 6152 there near the top left, so it's 2, 3, 4, 5 and jumps to 6152. Do you see that?
A Yes, ma'am.
Q So this is for the date 1/7/16, at time 12:30 in the morning, the flow at the Parmele transformer was point, positive .737, correct?
A .737 megawatts, yes, ma'am.
Q And it stays a positive flow all the way down until about eight rows up from the bottom, row 6175, at twelve noon it shifts to negative zero, right?
A Yes, negative .163.
Q Okay. And it stays negative for a couple of hours and then at 3:00 p.m. it looks like it shifts back to positive; is that right?
A That's right.
Q And then just to show on six months later on the following page, page 4, at the top the row 15126, this is July 12th at 12:30 in the morning, the flow at the same location, Parmele, was a positive .762. Do you see that?

A Yes.
Q And then if you go down to 8:30 in the morning, row 15142, it shifts to positive -- to negative, pardon me, and stays positive all the way with a small blip until 6:00 p.m. down at 15161, after which it shifts back to positive.
A Yes, for these particular two days, for this particular substation --
Q Right, exactly.
A -- that's the story.
Q As an illustrative example. And would you agree that that makes sense that when the sun is shining and this solar facility located at this location is producing that flows may go negative during --
A I have not nearly enough information to know. I don't know what the load shape looks like in aggregate at that substation. I don't know if any or how many QFs, solar or otherwise, are located within that substation. I couldn't possibly know from looking at this data what the story is. Your suggestion is certainly a plausible one that there is solar generation and that additional solar generation at this

substation would result in avoided line losses on January 7th, presuming the sun comes up before noon near this geographic location, but would not necessarily avoid line losses in the summer on July 12th except perhaps at 5:30 where there was positive flow and solar would, in fact, have avoided some line losses at that half hour, certainly more than zero.

Q I'm going to actually hand out one more exhibit to you that will help give a little bit more information about the picture at this location.

A Uh-huh.

MS. KELLS: Mr. Chairman, could this be marked as DNCP Vitolo Cross 2?

CHAIRMAN FINLEY: Yes.

DNCP Vitolo Cross Exhibit 2

(Identified)

BY MS. KELLS:

Q And so I'll -- I will tell you that this is the annual filing that Dominion makes with the Commission giving a queue status report for the interconnection queue for the Utility. And if you'll turn over to page 4, I'm sorry they're not numbered, but if you go to the fourth page over

there's some highlighting there. Do you see that?
A Yes.
Q And you see that the first item is a project of five megawatts capacity that is connected at Parmele.
A The first highlighted?
Q Yes, the first highlighted.
A NC13038 in the queue.
Q That's right. That's right.
A Yes.
Q So I'm going to ask you will you accept subject to check that this is the solar generation that is online at this facility as of now?
A It is certainly the solar generation that would be as part of an interconnection report. I don't know about any distributed solar that might also be at that substation. For example, rooftop solar which you wouldn't put on a queue report.
Q Okay. For purposes of this illustration.
A Yes.
Q So I'm going to back -- let's back up to the summary page of your -- of my exhibit. So you had two sets of data. You had a "With Entire

Dataset" and you had a "With New Start Date" data set. And so with the Entire Dataset you -- that says Number of Data Points 17904; is that correct?
A Uh-huh.
Q So that means, am I right, that there were 17904 half hour segments during this time period that the data covered?
A That's right.
Q Okay. And, as you mentioned earlier, you excluded from your analysis all of the data points which were zero?
A We ran it both ways to make sure that there wasn't a substantial change. But because we felt that the zero data points were not correct data, but rather a failure of a sensor, that it made sense to exclude them assuming that they occurred randomly throughout the sample, and we had no way to know that for sure.
Q So then you noted the total that's just non- -- that's NonZero --
A Correct.
Q And then you have the negative points which are 3855.

A Yes.
Q And then you -- am I right that you would calculate the percent of the total NonZero that's negative by dividing the negative by the total NonZero?
A Yes.
Q And came up with 22 percent negative and 78 percent positive for this location and designated it positive?
A Yes.
Q Now, in our terms we're using today positive means that, and under your analysis, the amount of time that the flow was positive was greater than the amount of time that the flow was --
A No, no.
Q Okay.
A So unfortunately Mr. Gaskill did not identify, at least anywhere that I could find, how he designated positive, neutral or negative. We could find no indication and so what we did was to -- to put some numbers behind it, we said if 75 to 100 percent of the time the flow was into the substation, we called that positive; 50 to 75 percent, we called it neutral; and if half the

time or more there was backflow, we called that negative, not having any information from Mr. Gaskill, and so when we did that we looked at the, we grouped the substations into positive, neutral and negative, and the -- of the substations that had backflow between 0 percent and 25 percent of the time, that is the positive substations where the flow was moving into 75 percent or more, we found that sure enough most of the time that was actually very close to 100 percent positive, almost no backflow. And similarly with the neutral where backflow occurred between 25 percent and 50 percent of the time, and we also analyzed the one substation for which there was backflow between 50 percent and 100 percent of the time.

Q Thank you for that. With the second batch of data that says "With New Start Date" and the number of data points is less, it's 12143; is that right?

A Yes, ma'am.

Q So that's because at this location you recognize that generation comes online and you were starting at the point in time at which a negative value was shown or --

A That's fairly close. So we have no way to know why there is a change from one half hour to the next. Most of the time it's just that load is changing. But because we knew that QFs were being installed and coming online sometime during this dataset for at least some of the substations, we wanted to think about the impact on the next QF, not the impact on QFs that are already under contract because that's already settled. What we wanted to focus on was whether or not there was line loss avoidance for the next QF. And so out of an abundance of caution we said let's analyze the data where a substation show any backflow at all starting at that first instance of backflow thinking that if a solar generator got plugged in the day before everything before that might not have backflow but now there might be backflow and that's the reality that Dominion would be facing now and the next QF would be coming in under that reality, so we need to think about line loss avoidance under that reality. And so for substations that had backflow and they didn't all, but for some stations that had backflow, we did a second analysis where we only started the analysis on that first instance of backflow so that we discarded the old history and were only considering the time period for which we believed it was likely that there was a QF solar or otherwise on that substation so that we could think about line loss avoidance in that new reality, not the history.

Q Right and I appreciate that you did that. So with this total of data points for the new start date, when you calculated that total it was over and that means the half hour, each half-hour period during the January to September 16th period of time; is that right?

A I'm sorry, can you repeat that? I just want to --

Q Your new start date data, the number of data points, 12143 --

A Yes.

Q -- as you just explained that how -- why you started that there so that that's the total of half-hour segments through the rest of the period?

A That's right. We omitted essentially the first 5500 or so --
Q Right.
A -- half hours because at that point you started to see backflow.
Q And the rest of your calculations flowed from that total number of data points?
A Right, a later start date but then the rest of the data inclusive.
Q And you -- as we've discussed, you removed the data points that were zero?
A That's right.
Q Okay. Did you -- you didn't remove any data points for half hours that occurred at night?
A No.
Q Okay. Would you agree that, for purposes of considering line loss from a solar generation facility, the appropriate half hours to look at are half-hour segments during the daytime --
A To me --
Q -- when the sun is shining?
A Dominion isn't proposing a solar-specific QF tariff and so if a QF comes along that's not solar it would use the exact same tariff sheet

and it might well be generating at night.
Q Excuse me.
A The -- we were interested in line loss for the proposed contract and it's not specific to solar.
Q Right.
A We were interested in all eligible QFs --
Q Right.
A -- be they solar or not --
Q Right. Do you --
A -- and so we did not distinguish between nighttime and daytime because there are eligible technologies that could apply for and receive that contract that could generate in any half hour along the day, the week or the month.
Q Do you know how many non-solar distributed QFs are on Dominion's system?
A No. But that says nothing about the next QF.
Q Would you agree with me that the vast majority of QFs coming online to the Utility systems these days are solar?
A In Dominion's North Carolina territory that sounds right.
Q And would you agree with me that in all likelihood the next QF, or a dozen QFs or 100 QFs

to come online will be solar?

A I would agree that a substantial number of the next 100 QFs will be solar. I will not agree with you that all of the next 100 QFs will be solar; I couldn't say that.

Q I meant to say majority.

A Yeah, that's right. I think that -- there's no question that you will have solar QFs. You may also have non-solar QFs.

Q We may but that's not -- in all likelihood, as we've discussed it's most likely solar. Would you agree with me then based on the pages 3 and 4 of the exhibit that I handed you that the negative values that are occurring are occurring during daytime hours?

A For this substation for these two days there are daytime hours showing negative and daytime hours showing positive.

Q Correct. But would you agree that all of the negative values are occurring during the daytime?

A You'll forgive me, I don't know sun-up and sun-down times on July 12th, but they do certainly -- there is certainly a solar correlation, right, but I don't want to --

Q They're between approximately 7:00 or 8:00 a.m. and 6:00 p.m., would you say?
A The first negative is at 8:30 a.m. in July so if the sun's up before that then it wouldn't be --
Q I will represent to you that the sun is up before 8:30 here in the summertime.
A Okay.
Q And then the last one was at 6:00 p.m. and there are none after that you can see on that chart?
A That's right.

MS. KELLS: Okay. I have nothing further.

CHAIRMAN FINLEY: Redirect?

MS. BOWEN: Just a few, Mr. Chairman.

REDIRECT EXAMINATION

BY MS. BOWEN:

Q Dr. Vitolo, in response to questions about DNCP's Cross Exhibit 1 that we were just looking at, when Ms. Kells initially asked about that you alluded to this is just focused on one substation and that other data may tell a different story. Can you please explain what you meant by that?
A Sure. The data that was provided by the Company and analyzed by Witness Gaskill covered 33 substations. I believe all 33 are owned or

operated by Dominion and in North Carolina. And these 33 substations all have a different load profile because there's different customers attached to each one of these 33, and also because there are zero or more than zero QFs currently plugged in, if you will, at each of these 33 substations. And so the story for one substation may not look much like the story for another. And so there are -- there are some substations in that dataset for which there is zero backflow on any half hour which suggests that any QF plugging in solar or not solar would avoid line losses for every single half hour that it was operating. There are other substations -- and that actually represents a good number of the 33 as my exhibit shows. There are other substations which have small amounts of backflow, a few percent of the half hours per year and that suggests that a solar QF or any QF that was operating on a relatively large number of hours, solar operates at about half the hours of the year approximately the sun's up half the time, actually it's a little more in North Carolina, that on those substations there are some half hours where it's not clear that that QF is avoiding line losses. But for most of the half hours there is not backflow which suggests that for those substations, for those half hours which represents most of the half hours at that substation a QF generating will avoided line losses. There are a small number of substations provided in the data where there is backflow 30 percent, 40 percent, 50 percent of the time. I think the largest amount of backflow, if you'll give me a moment, Whitaker's Number 2 is the only substation of the 33 that had backflow on more than half of the hours it operated. It's the only one. So for non-solar QFs, even that substation, Whitaker's 2, to the extent that it was generating during evening hours, it would avoid line losses. Additional solar at that substation, the line loss avoidance would be trivial or zero. But for the other 32 substations additional solar would avoid line losses on some hours or all hours, and non-solar QFs could also avoid line losses on some or all hours, and that's on 32 of the 33 substations. So to say that there's no line loss avoidance possible on any of the 33 substations because one of the 33 substations has backflow half of the time or more seems to me to be a mistake in calculating line loss avoidance.

Q Thank you, Dr. Vitolo. And then in response to a question from Ms. Fentress for Duke, she asked about your testimony and that you did not have -- you do not include a mention of a risk of overpayment in your testimony and you responded that you also do not include a discussion of the risk of underpayment in your testimony. Could you explain what you meant by a potential underpayment?

A Well, the conversation about overpayment henges on the idea that in 2014, or 2012, we looked at all of the information that was available to us and did our best job we could to project the future costs and we struck a price. And as the future has unfolded it appears now that we're certainly pay -- the price of natural gas and the cost of avoided energy now in 2017 is lower than we thought it would be in 2014. We don't know yet what the cost of energy will be in 2020 or 2025. We can only project just as we did back then. And so today the idea, the claim is that we are overpaying because, if we had not locked into a contract, we could buy the same commodity today on spot for less. Prices are lower now and if we strike a long-term contract now prices could go lower still, although there's only so much room left for natural gas to drop; you're not going to pay negative prices; or the price could go up a little bit or a lot; it could go up a little bit as markets equilibrate and then we'll have a good deal, we'll be paying a little bit less here in North Carolina for those contracts than we would have if we bought on spot; or perhaps something considerable changes in the next four or eight years, perhaps rules regarding hydro fracking either at the state or the federal level change and suddenly natural gas isn't quite as available as we thought it would be, well then the prices might change considerably. There are other reasons - perhaps, if God forbid, we go to war and there's a conflict that involves oil-generated countries, the global price of oil could go up and the natural gas price will come up with it. So it's possible that gas prices go up considerably. And, if they do, then having a long-term contract at the prices we're forecasting today will be a great deal for consumers because not only will they get the price stability that comes with a long-term contract that's not available for the electricity that is generated on their behalf from buying gas or coal in the markets but also it would be at a much lower price than would be available on the spot market. So there is a risk of overpayment but there's also a risk of underpayment.

MS. BOWEN: Thank you, Dr. Vitolo. I have no further redirect.

CHAIRMAN FINLEY: Questions by the Commission?

EXAMINATION

BY COMMISSIONER BROWN-BLAND:

Q Good afternoon. I just wanted to ask about the summertime/wintertime issue that you discuss on page 35 and 39 of your direct testimony.

A Yes, ma'am.

Q And I just wanted to be clear on your recommendation as to what the Commission do, as I read it, it's sort of a split recommendation based on different years.

A Uh-huh.

Q Could you elaborate?

A Sure. Just as when we calculate avoided energy we calculate a different price for each year and then levelize it, roll it up, we can do the same thing with capacity payments. We could say the avoided capacity dollar value is different in different years and roll it up. And that means that we could also say that the capacity split for winter and summer, that 80/20 number, is different in different years and have no problem rolling that up. And so, because the study that Duke cites considers the year 2019, it doesn't consider 2017 or 2018, I feel it's inappropriate to use the conclusions from what would happen in 2019, according to the study, and apply it two years before 2019. It didn't consider what would happen in 2017 and 2018. And so it seemed to me that Duke ought to keep its current split until such time as it has evidence for those specific years that the split should be different. And Duke did not present evidence that 2017 or 2018 were different than in the past. Their evidence begins in 2019, which is the start of their study.

My concern with their study is that the study assumed implicitly that Duke would do nothing to react to this new reality that wintertime capacity is more valuable to them than it used to be. So it assumes that Duke continues to procure the same amount of energy efficiency available for summer or winter peak than it has in the past back when summer was where the capacity was important. It presumes that the demand response availability available for summer and winter remains the same. Currently Duke has much more, many more megawatts of demand response available for summer than winter but that's because they're operating in a world where summertime capacity was more meaningful for reliability. Now that wintertime is becoming more meaningful I would expect that Duke will, in fact, attempt to procure low-cost wintertime capacity for reliability purposes and that could be additional energy efficiency; it could be additional demand response; it could also be wintertime-only capacity from nearby territories including PJM which is a summertime peaking RTO, implying that Duke may well be able to procure very inexpensive wintertime capacity for its reliability purposes. And if Duke does that then it won't be 80 percent winter, 20 percent summer, it would be something less, perhaps closer to 50/50. It's hard for me to know. My recommendation would be for Duke to revisit that study and recognize that now that it understands wintertime capacity is valuable for reliability it will go ahead and procure some at low prices and that will adjust this split closer to 50/50.

Q And what's -- if you know, what's the impact to the Company and the QFs with regard to this factor, this split?

A Well, we know that the QFs are paid for performance on capacity and so they're paid a capacity payment in the hours when we deem capacity to be important, if they perform in those hours. In the summer those hours are roughly weekdays in the afternoon; in the winter those hours are roughly in the early morning and the late afternoon; and there's Option A and

Option B. And I don't want to get too into the weeds but essentially the -- in general, we would expect solar QFs to get more of their total capacity compensation during summertime hours than during wintertime hours. And so, if we shift the summer/winter capacity split to emphasize winter hours more that results in solar QFs getting less total capacity compensation. If we emphasize summer more then solar QFs will get more capacity compensation.

Q And we've spent a lot of time in this whole proceeding talking about solar but these avoided cost rates as you understand it apply to all QFs?

A Yes, ma'am.

CHAIRMAN FINLEY: Other Commission questions? Questions on the Commission's questions?

(No response.)

MS. FENTRESS: No. No, thank you.

CHAIRMAN FINLEY: We will entertain introduction of exhibits SACE Vitolo Exhibit Number 1 and DNCP Vitolo Cross Examination Exhibits 1 and 2. Without objection, they shall be admitted into evidence.

MS. BOWEN: Thank you.

Vitolo Exhibit 1

(Admitted)

DNCP Vitolo Cross Exhibits 1 and 2

(Admitted)

CHAIRMAN FINLEY: Thank you, sir.

THE WITNESS: Thank you.

(The witness is excused.)

MR. VITOLO: That's good bedtime reading. You don't want to leave it here.

(Laughter)

BEN JOHNSON; was duly sworn and testified as follows:

DIRECT EXAMINATION

BY MS. MITCHELL:

Q Good afternoon, Dr. Johnson. Would you please state your name and your employer and your title for the record?

A Yes. My name is Ben Johnson. I have a firm called Ben Johnson Associates, Inc., and I'm the consulting Economist and President of that firm.

Q And what is your business address?

A 5600 Pimlico Drive, Tallahassee, Florida 32309.

Q And on whose behalf are you testifying in this proceeding?

A The North Carolina Sustainable Energy Association also known as NCSEA.

Q And did you cause to be prefiled in this docket on March 28, 2017, direct testimony consisting of 220 pages?

A Yes.

Q Did you also cause to be prefiled in this docket on April 17, 2017, corrected pages 77 through 79 of your testimony?

A Yes.

Q Do you have any additional corrections to make to your prefiled testimony at this time?

A There's only one that I thought was worth noting on page 202. On page 202 at line 6, at the number 90% should be 95% to match the graph.

Q And if I were to ask you the same questions today as indicated in your prefiled testimony, would your answers to them be the same as stated in your corrected prefiled testimony?

A Yes.

MS. MITCHELL: Chairman Finley, at this time I move that NCSEA Witness Johnson's corrected prefiled testimony be copied into the record as if delivered orally from the stand.

CHAIRMAN FINLEY: Dr. Johnson's corrected prefiled testimony filed on March 28, 2017, subsequently corrected, consisting of 220 pages is copied into the record as though given orally from the stand.

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

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Mar 28 2017

STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016

DIRECT TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

PUBLIC VERSION

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Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

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

A. I am a Consulting Economist and President of Ben Johnson Associates, Inc., a consulting firm that specializes in public utility regulation.

Q. PLEASE DISCUSS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics.

I have been actively involved in public utility regulation since 1974. Over the past four decades I have analyzed a wide range of different issues involving many types of regulated firms, participated in more than 400 regulatory dockets, and provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. The first time I recall was in 1983, when I testified in Docket No. P-55 Sub 834, a Southern Bell rate case. Since that time, my firm has participated in more than a dozen other proceedings before the North Carolina Utilities Commission ("NCUC" or the "Commission"). I testified in most, but not all, of these proceedings. In most of these cases I testified on behalf of the Public Staff. However, on some occasions, as in this case, our firm provided assistance to other parties, instead.

Our firm's past consulting engagements in North Carolina include: Docket No. E-100, Sub 53, a 1986 proceeding concerning avoided costs; Docket No. E-2 Sub 537, a 1986 Carolina Power & Light rate case in which we assisted Public Staff with reviewing the prudence of the Shearon Harris nuclear plant; Docket Number E-100, Sub 57, a 1988 proceeding concerning avoided costs; Docket No. E-100, Sub 66, a 1993 proceeding concerning avoided costs; Docket No. E-100, Sub 74, a 1995 proceeding concerning avoided costs; Docket No. E-100, Sub 75, a 1995 proceeding concerning Least Cost Integrated Resource

Planning; Docket No. E-7, Sub 1013 a 2001 proceeding in which Duke Energy Corp requested permission to issue stock in connection with its proposed acquisition of Westcoast Energy, Inc.; Docket Number E-2, Sub 760, the 2000 proceeding in which CP&L Holdings, Inc. requested permission to acquire Florida Progress Corporation; Docket Nos. E-7, Sub 828 & 829 E-100, Sub 112, a 2007 Duke Energy Carolinas case; Docket Nos. E-7, Sub 909, a 2009 Duke Energy Carolinas rate case; Docket No. E-2, Sub 966, an avoided cost arbitration between Capital Power Corporation and Progress Energy Carolina, Inc.; Docket No. E-22, Sub 459 a 2010 Dominion North Carolina Power rate case; Docket No. E-2, Sub 1023 a 2012 Progress Energy rate case; Docket No. E-22, Sub 479, a 2012 Dominion North Carolina Power rate case; Docket No. E-100, Sub 136 the 2012 proceeding concerning avoided costs and Docket No. E-100, Sub 140 the 2014 proceeding concerning avoided costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My firm has been retained by the North Carolina Sustainable Energy Association ("NCSEA") to evaluate the concerns expressed by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") ("Duke") and Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") (all three collectively, the "Utilities") in their November 15, 2016 filings (the "initial filings") and in their testimony with respect to alleged problems related to growth in solar generation and the Commission's long-standing approach to implementing the Public Utility Regulatory Policies Act of 1978 ("PURPA"). In addition, I have reviewed the Utilities' proposed changes to the peaker methodology and input parameters and assumptions used in developing the new rates they are proposing to pay to Qualifying Facilities ("QFs").[1] I have also developed recommendations for how the Commission can resolve the concerns identified by the Utilities, protect the interests of the using and consuming public in North Carolina, and encourage continued investment in the state by small power producers.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following these introductory remarks, there are seven major sections to my testimony.

In the first section, I discuss North Carolina's implementation of PURPA, as compared with other states.

In the second section, I discuss recent growth in solar production and related concerns that have been identified by the Utilities. I also briefly discuss a few of the proposals offered by the Utilities in response to these concerns. However, most of my detailed discussion of the Utilities' proposals is reserved for later sections, where I offer some alternatives which I believe would be at

1 16 U.S.C. § 824a-3

least as effective in resolving the Utilities' stated concerns, while better serving the interests of the using and consuming public in North Carolina.

In the third section, I compare the avoided cost rates approved by the Commission in Docket No. E-100, Sub 140 ("2014 QF rates") and the proposed QF rates. This portion of my testimony includes a discussion of marginal and average energy costs and some comparisons between the QF rates and some benchmark long run avoided cost estimates.

In the fourth section, I discuss the "indifference" standard under PURPA, the concept of avoided costs, and the three standard methods for estimating avoided costs. I also explain my estimates of long run avoided capacity and energy costs, which I use at various points in my testimony. These cost estimates are not intended to be used in establishing the tariff rates in this proceeding – which I assume will continue to be developed in accordance with the same methodology which the Commission has historically used, including the refinements adopted by the Commission in its December 31, 2014 Order Setting Avoided Cost Input Parameters ("Order Setting Parameters").[2] Instead, these cost estimates are offered as a benchmark for comparison, and to help illustrate and clarify various points in my testimony, particularly with respect to different technologies, fuel prices and scenarios.

2 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140. December 31, 2014.

Generally, in the remaining sections I respond to specific proposals offered by the Utilities and offer some alternatives, which I believe will be at least as effective as the Utilities' proposals in resolving the Utilities' stated concerns, while better serving the interests of ratepayers.

Specifically, in the fifth section, I discuss the proposed QF energy rates, including the proposal to no longer offer fixed long-term rates. From the perspective of both QFs and ratepayers, this is a "lose-lose" proposition. It would significantly increase the risks borne by QFs, and make it more difficult to finance QF projects, while simultaneously increasing (not decreasing) the risks borne by ratepayers. In this section I also discuss the use of forward market data and fundamental forecasts, with a particular focus on Duke's proposal to exclusively rely on forward market data in developing their proposed QF energy rates. I also discuss some geography-related issues, including DNCP's proposal to reduce its avoided cost energy rates based on the historical energy price differences between the DOM Zone and the North Carolina service area.

In the sixth section I discuss the proposed QF capacity rates, including the proposal to value capacity at zero during some years, as well as the proposal to reduce the Performance Adjustment Factor from 1.20 to 1.05 based upon the availability of a new combustion turbine, rather than the performance of the Utilities' entire fleet of generating units, including baseload units, as the Commission has historically required.

In the seventh section, I discuss various issues related to seasonality and time of day, including Duke's proposal to no longer give 60% weight to the summer season and 40% weight to the winter season, and to instead give 20% weight to the summer and 80% weight to the winter. In this section I also discuss Duke's proposals to modify their standard QF contract terms and conditions to allow them to curtail QF energy output and discontinue QF purchases during loosely defined emergency periods. I also offer two alternative suggestions which would be much less heavy-handed and damaging to the financial viability of QFs, while still resolving the Utilities' stated concerns, thereby better advancing the interests of North Carolina ratepayers.

Section 1: PURPA Implementation in North Carolina and Other States

Q. **HAS INCREASED DEVELOPMENT OF RENEWABLE ENERGY SOURCES BEEN A LONGSTANDING GOAL OF PUBLIC POLICY MAKERS?**

A. Yes. Since the Energy Crisis of the mid-1970s, many steps have been taken at both the state and federal level in an effort to reduce our reliance on traditional energy sources – particularly imported oil – to encourage greater energy independence and diversity. While many different tools have been used at various levels of government, including tax policies and incentives, some of the earliest steps were taken by the United States Congress in 1978 when it adopted PURPA.

Looking at the relevant portions of this law from my perspective as an economist, it appears to advance at least two distinct goals. First, it encourages expanded use of targeted technologies and energy sources which had been neglected by the electric utility industry. Second, it encourages investment in small power producers – new firms that enter the market to develop these targeted technologies and energy sources.

Q. DID PURPA ENCOURAGE SOLAR PRODUCTION BY NON-UTILITY GENERATORS?

A. Yes. PURPA advanced an "all of the above" energy strategy, which was intended to encourage greater energy independence and increased supply diversity in the United States. PURPA requires electric utilities to purchase electrical energy from a special category of independent power producers, known as QFs that was established by Congress for this purpose, including ones that specialize in solar energy production.[3]

3 16 U.S.C. § 824a-3.

More specifically, PURPA requires the Federal Energy Regulatory Commission ("FERC") to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity."[4] The scope of this portion of PURPA was narrowly focused. Utilities were exempted from any requirement to purchase from independent power producers that used the energy sources that had been historically been favored by electric utilities, like coal, residual oil, nuclear, and natural gas. Instead, Congress focused on certain unconventional energy sources, including cogeneration, which had not been aggressively pursued by utilities.

Although they do not typically involve renewable energy sources, cogeneration facilities (which are specialized installations that produce electric power in conjunction with another form of energy, like the production of heat or steam for use in a manufacturing process) were also a good match for both goals. Congress apparently was convinced this was a cost-effective and energy-efficient technology which had the potential for more widespread deployment than had been observed up to that time. By prohibiting utilities from discriminating against this efficient energy source, the goals of increased, targeted competition and increased energy independence and diversity would both be advanced.

4 16 U.S.C. § 824a-3(a).

Other targeted technologies include electricity produced from biomass and waste, as well as renewable resources like wind, small hydro, and geothermal energy. The primary purpose in encouraging investment in these specialized energy sources was similar to the reason why cogeneration was targeted: if PURPA were successful in encouraging new entry, supply diversity would be improved, and the country would reduce its dependence on scarce and nonrenewable resources like coal and oil.

Q. CAN YOU ELABORATE ON THE SECOND GOAL YOU MENTIONED – ENCOURAGING TARGETED COMPETITION FROM SMALL POWER PRODUCERS?

A. Yes. By requiring utilities to purchase from QFs, Congress was not only encouraging diversity of energy supply sources, but it was also pursuing a strategy of encouraging narrowly targeted competition in electric power production. PURPA was adopted at a time when public policy makers were trying to scale back unnecessary regulations, improve regulatory structures, and rely more on competition to advance the public interest – particularly in industries, like the electric power industry, where competition had been (intentionally or unintentionally) effectively suppressed by government policy.

Perhaps the most memorable and visible example of this new market-oriented policy approach was the deregulation of airlines, which occurred around the same time. In that industry, safety continued to be tightly regulated, but other rules were changed to remove barriers to entry, encourage new airlines to challenge incumbent firms and to deregulate prices, which had previously been tightly controlled. The resulting increase in competition successfully unleashed a tidal wave of innovations, cost cutting, and price reductions.

Although PURPA was not as visible or dramatic, it reflected much the same pro-competitive philosophy underpinning airline deregulation. Congress sought to gain some of the benefits of increased competition without foregoing the benefits of traditional rate base regulation. The idea was to retain existing constraints on monopoly power in retail markets, while introducing new, carefully thought-through constraints on monopsony power in wholesale markets. The key to this strategy was encouraging increased investment and new entry by small, independent power producers, who had the potential to unleash downward pressures on the incumbents' costs and retail prices, without taking the risk of fully deregulating an industry which had many of the characteristics of a natural monopoly.

Thus, it is fair to say that one of the fundamental goals of this portion of PURPA was to encourage, on a narrowly targeted basis, increased competition in the market for electrical generation without jeopardizing continued regulation of other aspects of the industry. The strategy was straightforward: encourage investment in small firms that would use unconventional technologies to produce electricity in competition with the existing, vertically integrated electric utilities.

Q. WHY WAS THIS SORT OF ENCOURAGEMENT NEEDED?

A. Prior to the adoption of PURPA, most electric utilities obtained all, or nearly all, of their power from large centralized generating plants that they owned and constructed themselves, or from similar plants operated by a nearby utility. Congress made a conscious decision in 1978 to deviate from this historical pattern by encouraging investment in small power producers (80 MW or less at any single site) that would compete with the vertically integrated utilities, provided they focused on the targeted generation technologies.

Before PURPA, the monopoly power enjoyed by electric utilities in the transmission and distribution of electricity and the regulatory apparatus designed to constrain that monopoly power combined to discourage competition. This was true even for parts of the electric industry – like generation – which did not seem to exhibit the characteristics of a natural monopoly.

For example, before PURPA, few industrial firms would consider generating their own power, even where this would be economically efficient (e.g. utilizing waste heat from the manufacturing process), because there was not a ready market for power produced in excess of the firm's own needs. Practical constraints, as well as legal barriers associated with monopoly regulation, made it difficult or impossible for industrial firms to sell power to anyone other than the local utility, and most utilities weren't interested in buying power from new entrants. Rather, electric utilities generally preferred obtaining power from conventional generating plants – particularly ones they owned and operated themselves.

Before PURPA changed the regulatory landscape, the utility's preference for owning and operating its own generating plants using conventional energy sources nearly always prevailed over what might otherwise have been commercially viable transactions to purchase from independent power producers that would have ultimately benefited the utilities' customers. The utility was largely immune from pressures to pursue unfamiliar technologies or to buy from independent power producers, because it was effectively both a monopolist (single seller) and a monopsonist (single buyer), within its particular service territory.

Thus, for example, unless an industrial firm was willing to pull up stakes and move to another state, it was forced to pay whatever price the utility charged for whatever power it used, and it was forced to accept whatever price (typically much lower) the utility was willing to pay for any extra power the industrial firm produced. Before PURPA, if the gap between the price charged by the utility for power supplied to the industrial firm and the price paid by the utility for power received from the industrial firm seemed unduly large, the industrial firm could in theory complain to the state regulator about the magnitude of the gap, and ask the regulator to require the utility to pay a higher price. In practice, however, this option was generally too costly and risky to be worth pursuing. Accordingly, before PURPA, most industrial firms ignored the potential for cogeneration, regardless of how attractive the underlying economics might be, rather than risk undertaking an investment that would be subject to the utility's unconstrained monopsony power, or the uncertain outcome of future regulatory decisions.

This problem was not limited to cogeneration by industrial firms – it also affected the viability of investments in power production by small run-of-river hydro plants and other opportunities that existed for generating electrical power on a small scale. The utility was typically the sole buyer of power in the local market, and it controlled interconnection to the power grid, thereby largely determining the viability of small power production by other firms. Absent a well-defined system of constraints on the utility's monopsony power, small power production was an enormously risky proposition that few investors were willing to seriously contemplate.

Q. CAN YOU BRIEFLY ELABORATE ON THE DISTINCTION BETWEEN MONOPOLY POWER AND MONOPSONY POWER, AS IT RELATES TO UTILITY REGULATION?

A. Yes. By the early 1900s in most jurisdictions, a comprehensive system of regulation to control monopoly power had evolved, which severely limited the ability of electric utilities to impose unreasonable prices, terms, and conditions on their sales transactions with most retail customers. In contrast, prior to the adoption of PURPA, relatively little thought was given to monopsony power (which exists when a single buyer dominates the market). In most jurisdictions, no comparable comprehensive regulatory mechanisms existed to constrain monopsony power, or prevent electric utilities from using this power to suppress competition from independent power producers.

As the primary or exclusive potential buyer of electrical energy within their respective market areas, the incumbent electric utilities enjoyed as much "monopsony power" when buying electricity as the "monopoly power" they had when selling energy. Taking advantage of their market power, utilities generally decided to construct, own and operate their own generating units, or to purchase power from neighboring utilities, rather than buying from independent firms.

In general, incumbent utilities prevented, or at least discouraged, competitive entry by other firms, even in situations where those firms had a clear efficiency advantage (e.g. the ability to generate electricity less expensively, by taking advantage of waste heat involved in industrial processes), or they were willing to take greater risks in trying new, less familiar technologies.

Whether or not it was intentional, the result was that electric utilities prevented the consuming public from seeing the benefits of competition by independent power producers, who could potentially bring down costs and bring long term societal benefits by increasing supply source diversity, experimenting with innovative technologies, reducing costs, increasing efficiency, or accepting lower profit margins.

In sum, the potential benefits from imposing regulatory constraints on monopsony power are conceptually similar to the reasons why the monopoly power of the incumbent utilities have long been constrained. However, the existence of monopsony power, and the benefits from constraining it, have not been as widely understood or effectively dealt with.

Q. WHY DO UTILITIES PREFER THEIR OWN GENERATING FACILITIES?

A. There are multiple factors which help explain why electric utilities have historically resisted purchasing from competing firms. First, there is a natural tendency for utility company management to want to retain maximum direct control over system reliability and other outcomes for which they are ultimately accountable. Second, management operates within the context of a growth-oriented U.S. corporate culture, which favors expansion of a firm's staff, assets, income, and earnings per share. Third, management is expected to maximize profits and value for its stockholders, which leads to a strong bias in favor of expanding the rate base, due to the Averch-Johnson effect.[5]

With PURPA, Congress attempted to overcome this resistance by reducing barriers to competitive entry into the electric utility industry without disrupting the more successful aspects of traditional rate base regulation. It did this by providing an overarching federal regulatory structure for implementing state regulatory oversight of transactions between electric utilities and QFs, with a view toward encouraging QF investment.

However, PURPA did not change the attitudes or preferences of the incumbent utilities. These firms continue to prefer owning and operating their own generating resources for perfectly rational reasons. If the benefits of competitive entry are going to fully emerge, it is necessary for state and federal

5 Named after the authors of a famous article published in 1962 in the American Economic Review, which demonstrated that under typical conditions, rational rate base regulated firms will tend to expand their capital investment beyond the optimal point of maximum economic efficiency. This tendency occurs whenever the allowed rate of return exceeds the utility's actual cost of capital by even a small margin. Theoretically the Averch-Johnson effect could be avoided if the allowed rate of return were set precisely equal to the cost of capital. However, this degree of precision isn't achievable in practice. As well, an allowed return which exceeds a barebones estimate of the cost of capital can be viewed as preferable, since it helps maintain the utility's financial integrity, strengthens its financial ratios and protects its bond rating.

regulators to actively implement the provisions of PURPA in a way that fulfills the goal of encouraging competitive entry, and placing greater reliance on market forces to advance the interests of ratepayers and the public good.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMMISSION'S ROLE IN IMPLEMENTING PURPA?

A. State commissions have an important role in implementing PURPA, together with FERC and the courts.

> Questions about the actual avoided-cost determinations are litigated before the state commissions or the state courts with applicable jurisdiction for non-regulated utilities. Questions regarding whether a method of avoided-cost determination is consistent with PURPA and FERC implementation rules are litigated before FERC or an applicable federal court. [6]

State commissions have been provided with extensive guidance for how they are to carry out their responsibilities, both in the text of the underlying statute, and in rules adopted by FERC which were subsequently upheld by the United States Supreme Court.[7]

6 PURPA Title II Compliance Manual, p. 15. The PURPA Title II Compliance Manual was jointly published by the American Public Power Association ("APPA"), Edison Electric Institute ("EEI"), National Association of Regulatory Commissioners ("NARUC") and National Rural Electric Cooperative Association ("NRECA") on March 2014, with the intended purpose of being used as an aid to state commissions and utilities as they deal with issues related to PURPA.

7 American Paper Institute, Inc. v. American Electric Power Service. Corp., 461 U.S. 402, 103 S.Ct. 1921 (1983).

Rates for purchases from QFs ("QF rates") must: (a) be just and reasonable to the electric consumers of the electric utility and in the public interest; (b) not discriminate against qualifying cogenerators or qualifying small power producers; and (c) cannot exceed "the incremental cost to the electric utility of alternative electric energy."[8]

While I am not an attorney, it is my understanding as an economist that under PURPA the Commission is expected to (a) require utilities to purchase energy and capacity from QFs on terms consistent with all applicable FERC regulations; (b) treat avoided costs as the pricing floor for those purchases; (c) enforce the legal right for QFs to sell power to utilities on either an as-available basis, or pursuant to a "Legally Enforceable Obligation" ("LEO") at the QF's option; (d) enforce the legal right for QFs to sell power to utilities pursuant to long-term contracts; and (e) ensure utilities provide nondiscriminatory interconnection and/or transmission service to QFs that they sell power to QFs on request.

Q. HAS THIS COMMISSION'S EXPERIENCE WITH IMPLEMENTING PURPA BEEN TYPICAL?

A. For more than 30 years this Commission and the Public Staff have invested a high level of effort studying the issues involved with PURPA, endeavoring to

8 16 U.S.C. § 824a-3(a).

strike the appropriate balance by encouraging small power production while protecting ratepayers. These efforts are evidenced by the long series of actively litigated biennial rate proceedings where the Utilities' proposals related to implementation of PURPA were subjected to a high degree of scrutiny by the Public Staff and other interested parties.

The Commission has also occasionally probed even more deeply into specific issues – a notable example being the nearly year-long investigation into input parameters and methods for calculating avoided costs which recently occurred in the 2014 biennial avoided cost proceeding. In contrast, in many other states there simply has not been as much interest in QF development, and the incumbent utilities' implementation of their PURPA obligations have not been subjected to a comparable level of intense scrutiny.

Q. WHY HAS NORTH CAROLINA'S EXPERIENCE WITH PURPA BEEN DIFFERENT THAN IN OTHER STATES?

A. There are many factors involved, including the fact that in some other states PURPA issues remain largely unfamiliar and because these issues arise in the context of highly specialized tariff filings which have an immediate, direct effect on very few people.

In fact, unless and until independent power producers actually enter a given market to compete with the state's utilities, there may not be anyone in that state for whom accurate QF rates are a top priority, or who can justify expending the effort required to intervene into the regulatory process in order to challenge the utility's QF rate calculations.

Q. CAN YOU PROVIDE SOME EXAMPLES OF HOW PURPA HAS BEEN IMPLEMENTED DIFFERENTLY IN OTHER STATES?

A. Yes. For one thing, some states have adopted regulatory systems that rely on broader forms of competition, which tend to supplant or suppress the more narrowly focused forms of competition envisioned in PURPA. Even where broader forms of competition have not been introduced, the utilities have sometimes been successful in avoiding long term fixed rate standard offer QF tariffs, or limiting the scope of these tariffs to very small QFs. As a result, in some states potential entrants are largely forced to negotiate rates and other terms and conditions, because the standard offer tariff is only available for extremely small projects, or it only provides high risk variable rates, which make it difficult (or impossible) to finance a QF project.

At least theoretically, these limitations could be overcome through negotiations and, if necessary, arbitration. However, from a potential entrant's perspective, this process is much more difficult, time consuming and costly than simply choosing to accept the published tariff or choosing to pursue better investment opportunities elsewhere.

In states with QF tariffs that do not offer certain critical elements (like long term contracts with fixed rates and reasonable terms and conditions), potential entrants may be reluctant to invest the time and effort required to negotiate with the local utility, since the outcome this investment is so unpredictable, with a high risk of failure. Since negotiations are time consuming, risky and costly, firms may be discouraged from entering a state unless and until after acceptable standard offer rates and terms have been published. Thus, a "chicken and egg" phenomenon can arise, in which few, if any, firms with QF experience become active in a state, and no one already in the state is willing to expend the effort required to deeply investigate the issues and advocate the sorts of changes that are needed to make QF investment more attractive.

While continued resistance to QF entry on the part of the incumbent utilities is readily predicted and explained as a matter of economic theory, it is important to realize this is not a merely speculative or theoretical concern, but a fundamental aspect of the industry. Succinctly stated, in a typical retail rate proceeding, the utility will often seek rates that are higher than necessary or appropriate, but in a QF rate proceeding the reverse is true: the utility will often seek rates that are lower than necessary or appropriate.

In my experience, utility companies have consistently preferred setting QF rates at relatively low levels, and have advocated proposals that have the effect of discouraging QF investment and justifying continued expansion of their own rate base instead. In some states, QF tariffs have sometimes been adopted with little or no change from the way they were initially proposed. The Commission should keep this in mind, when comparing the situation in North Carolina with that in other states.

Q. CAN YOU ELABORATE ON DIFFERENCES BETWEEN THE WAY PURPA HAS BEEN IMPLEMENTED IN NORTH CAROLINA COMPARED TO SOME OTHER STATES?

A. Yes. In response to discovery, Duke provided some valuable information concerning implementation of PURPA in some nearby states – and in most cases the differences are stark. For instance, Alabama, Arkansas, Florida, Kentucky, Louisiana Maryland, and Virginia offer variable, rather than fixed long term rates. This is a hugely important difference, since variable rates greatly increase the riskiness of solar projects, which have high fixed costs and low variable costs.[9]

9 Duke's Response to NCSEA's first data request ("NCSEADR1"), request 9 ("NCSEADR1-9").

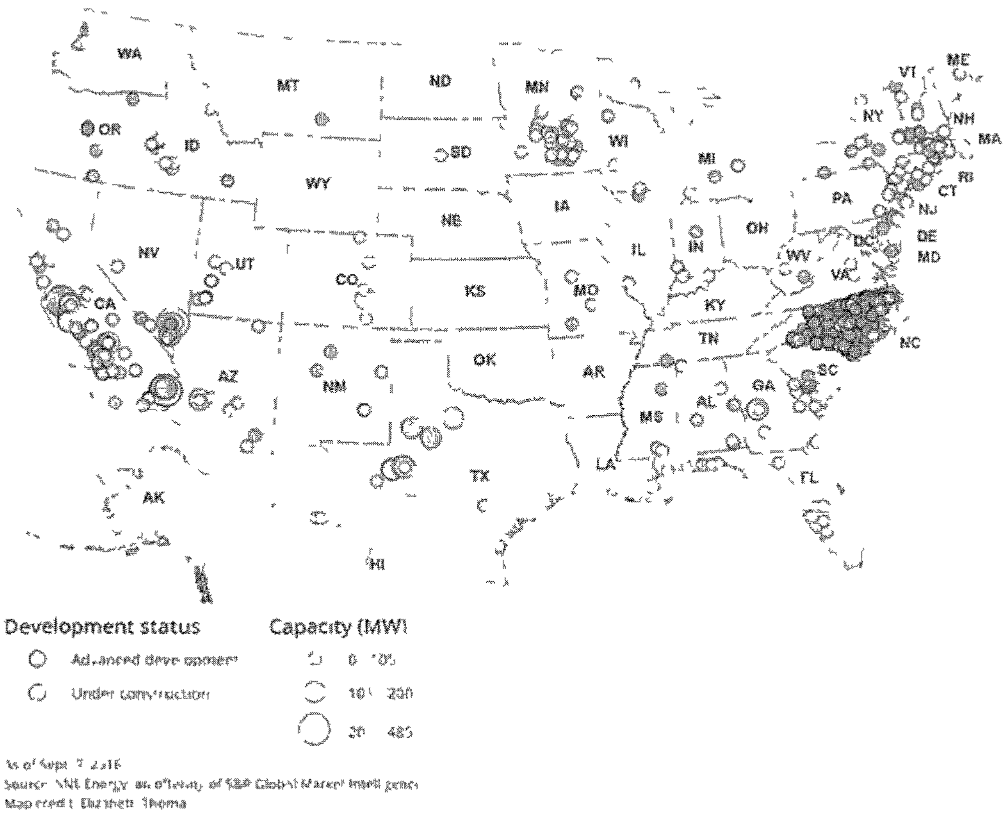
Similarly, QFs are forced to negotiate rates, terms and conditions in Alabama, Georgia, Maryland, Mississippi, and West Virginia, because the standard offer tariff is only available to QFs with nameplate capacity of 100 kW (one-tenth of 1 MW). In fact, aside from Tennessee, the only state cited by Duke which offers fixed long-term rates to QFs larger than 100 kW is South Carolina – where Duke's QF tariffs are largely identical to those approved by this Commission.

Q. HAS THERE BEEN MORE QF DEVELOPMENT IN NORTH CAROLINA THAN IN MOST OTHER STATES?

A. Yes. The following map demonstrates that solar investment in North Carolina has been different than in most other states.[10] More specifically, it confirms my impression that North Carolina has more solar generating projects than most nearby states, including states like Alabama, Florida, Georgia, Louisiana, and Mississippi, which continue to regulate utilities in the traditional manner. As, it appears North Carolina has more geographically dispersed projects than in most other states.

10 An earlier version of this map appears on page 17 of the Joint Initial Statement Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress. LLC filed in N.C.U.C. Docket No. E-100, Sub 148, November 15, 2016 and on page 36 the Direct Testimony of Kendal C. Bowman on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Bowman Direct").

US planned utility-scale solar projects in advanced development or under construction



The contrast with states like Arkansas, Kentucky, Louisiana, Oklahoma and Tennessee, which have very little solar activity, is particularly striking However, these states are not alone in lagging behind their potential. Even Florida – despite its branding as the "Sunshine State" – has far fewer solar projects compared to North Carolina – relative to the size of the land mass and population of each state.

Of course, the way one views this map can be reminiscent of whether one sees a glass that is half empty, or one that is half full. What this map does not tell us is whether North Carolina is doing something right, and states like Florida and Louisiana could benefit from emulating it, or whether North Carolina it is doing something wrong, and should change its approach to implementing PURPA, in order to achieve outcomes that are more like these other states.

Q. ARE THESE DIFFERENCES ENTIRELY NEW?

A. No. My impression is that some differences have existed for many years, and can be traced all the way back to the availability of small hydro development opportunities in North Carolina that simply did not exist in most other states. In part due to the desire to take better advantage of this hydro potential, beginning in the 1980's the Public Staff invested a large amount of effort investigating the best way to fulfill the purpose of PURPA, while protecting the interests of the using and consuming public. This effort helped overcome the typical "chicken and egg" phenomenon I alluded to earlier, since small QFs were no longer forced to engage in time consuming, risky and costly negotiations.

Q. ARE THERE ANY OTHER NOTABLE DIFFERENCES BETWEEN NORTH CAROLINA AND OTHER STATES?

A. Yes. In some states, growth in renewables has been almost entirely driven by mechanisms like state renewable portfolio standards and government mandated procurement obligations.[11] While these approaches have increased the use of sustainable energy sources, there are some important differences. Realizing that the size of the yellow and red circles on the map indicate the size of each project, it is apparent that states like California, Texas and Florida are being developed with relatively large projects.

When comparing North Carolina with other states, it is reasonable to conclude that differences in PURPA implementation contribute to differences in the outcomes – but it should be acknowledged other explanatory factors are also relevant. Some of North Carolina's success in attracting solar investment could be attributable to some of the same factors which explain why the Research Triangle has attracted high-tech firms, Charlotte has become a major banking hub, and so many other businesses have been drawn to the state in recent years. Additionally, and increasingly, many large customers in the state, including the military, some new industrials, and some high-tech firms, are increasingly interested in obtaining energy that is sourced from renewable resources. Duke's Green Source Rider Program is evidence of this fact.

However, when looking at the state's success in attracting investment in solar energy in particular, three important considerations have greatly added to the state's appeal. First, the state has a favorable meteorological climate, with

11 GTM Research, The Next Wave of U.S. Utility Solar, Procurement Beyond the RPS (Feb.2016), accessible at https://www.greentechmedia.com/research/report/the-next-wave-of-us-utility-solar.

more solar radiation and less winter cloud cover than many other states. Second, the state has had a favorable legislative climate, with tax incentives, Renewable Energy Portfolio Standards, and other policies intended to encourage investment in renewable energy. Third, the state has had a favorable regulatory climate, with a long history of closely scrutinizing QF tariffs to ensure they are fully consistent with the requirements of PURPA, while also protecting the interests of the state's ratepayers. Fourth, the incumbent utilities have carefully complied with REPS and their PURPA obligations, including (for example) negotiating in good faith with QFs that were interested in pursuing arrangements that differ from the standard offer tariff.

Q. ARE THERE BENEFITS TO NUMEROUS SMALL QFs, RATHER THAN MOSTLY LARGER UTILITY-CONTROLLED PROJECTS?

A. Yes. There are significant public policy, economic efficiency, energy security, price stability, and economic development benefits to small, independently owned power production. While all energy projects share some benefits, there are additional benefits to QF projects which are not readily achieved with development of large, central generating stations by utilities.

First and foremost, competition from small power producers provides additional long-term benefits to consumers and the state economy as a whole, because it provides a healthy check on the monopoly power of the utilities, helping to constrain costs and keep rates at more affordable levels over the long term. Competition can bring long term societal benefits that are not readily achieved through other mechanisms, like a utility-controlled procurement process.

Supply source diversity can be greatly increased when market opportunities are not limited to an administratively constrained and managed RFP process. Some firms might not be successful at writing proposals or jumping through all the administrative hoops required by an RFP process, yet succeed as a QF. The difference in business models is subtle, but important. QFs have the opportunity to sell the utility as much power as they want, at a published tariffed rate. Hence, the keys to success are raising capital, developing innovative technologies, driving down costs, and increasing efficiency – or being willing to accept lower profit margins in return for the greater freedom and long-term upside potential that is inherent to the QF business model.

Second, QF development tends to reduce the risks posed to the state's economy by widely fluctuating coal and natural gas prices. From the perspective of retail ratepayers, QF energy is particularly attractive when it is purchased at fixed prices pursuant to long-term contracts, because these contracts provide a stabilizing element in the utilities' cost structure, thereby reducing volatility in retail prices. This reduced volatility also helps strengthen the state's economy and provides a more stable and attractive business environment.

Third, QF development helps diversify the state's energy mix and reduces the state's exposure to future uncertainties related to overseas geo-political events and the price of crude oil (which influence gas and coal prices), as well as the state's exposure to future political uncertainties related to coal and other traditional fuel sources. In most cases utilities continue to favor traditional technologies like coal, gas, and nuclear. While renewable energy development is being achieved in some other states, much of this investment is limited to, and being channeled through, government mandated or controlled procurement processes. While government quotas and mandates can be effective in jump-starting the use of alternative technologies, over the long haul its much more effective to set up a system that encourages market-driven investment decisions, rather than relying exclusively on administrative decision-making processes.

Fourth, QF investment provides widespread economic benefits to the local communities where these facilities are located – including substantial enhancements to the local tax base and property tax collections, without burdening local infrastructure or creating a corresponding need for additional government services. The net impact is a clear and significant benefit for local communities where these facilities are sited and installed – benefits that will not be achieved if solar, biomass, and other types of QFs are discouraged from investing in the state, and the focus is on developing much larger, more centralized generating units.

Fifth, when QF investment is encouraged on a widely-dispersed basis, the state's growing energy needs can be met with less need for costly expansion of the state's high voltage transmission systems – expansion that is all but inevitable if the state relies exclusively on construction of very large central generating units by the utilities in a small number of remote locations.

Section 2: Uncontrolled Growth in Solar Production

Q. HAS NORTH CAROLINA BEEN EXPERIENCING SIGNIFICANT GROWTH IN SOLAR PRODUCTION?

A. Yes. Witnesses for all three Utilities have described what they refer to as "unprecedented" growth in solar energy within the state:

> As a result of regulatory and legislative policies, strong support by DEC and DEP, and aggressive construction and deployment of solar facilities by developers, North Carolina is second only to California in interconnected solar capacity. As of December 31, 2016, there are more than 1,600 MW of third-party developed solar connected to DEC's and DEP's grid in North Carolina, with another

> 4,900 MW progressing through the interconnection queue.[12]

> ...as of February 1, 2017, DNCP has 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina. (The Company has executed 9 PPAs totaling 45 MW even since the Initial Comments were filed just three months ago.) Of these 500 MW, approximately 350 MW have already commenced commercial operation, while the remaining 150 MW is under various stages of development. This is a mere three years since February 2014, when the Company had only 58 MW of distributed solar capacity under contract, with one project operational.[13]

Q. IS THIS DIFFERENT THAN WHAT IS HAPPENING IN NEIGHBORING STATES?

A. Yes. The growth North Carolina is experiencing is both substantial and more rapid than the relatively leisurely pace at which solar activity is occurring in nearby states like Alabama, Florida, Georgia, Indiana, Kentucky, Louisiana, Mississippi, and Virginia. Mr. Yates describes Duke Energy Corporation as a "national leader in renewable energy"[14] and points to massive investments it has made in North Carolina and elsewhere:

> Since 2007, Duke Energy has invested approximately $5.8 billion in renewable generation projects, including nearly

12 Direct Testimony of Lloyd M. Yates on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Yates Direct"), p. 6.

13 Direct Testimony of J. Scott Gaskill on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Gaskill Direct"), p.8

14 Yates Direct, p. 5.

> $300 million by DEP and $175 million by DEC in North Carolina.[15]

Yet, it is important to put this investment into context. In fact, all forms of renewable energy remain a very small share of Duke Energy Corporation's total electrical production. Duke Energy Corporation reported that its Hydroelectric and Solar facilities <u>combined</u> provided just 0.7% of its total generation during 2016 – and this was actually down from the 0.8% which was achieved in 2015 and 0.8% in 2014.[16]

When comparisons are made between solar nameplate capacity and other types of capacity, growth in solar generation can appear to be more significant than it really is. For instance, in its 2015 Annual Report to Stockholders, Duke Energy Corporation reported that Hydro and Solar represented 7.0% of its "owned capacity" while simultaneously reporting that Hydro and Solar generated just 1% of its total net output in gigawatt-hours ("Gwh").[17] While both statistics are interesting, the latter statistic is far more relevant and provides a better perspective on where things actually stand.

For more than 30 years, state and federal policy makers have been seeking to reduce dependence on imported energy sources, and increase the use of renewable energy sources. The focus of these efforts has always been on

15 Id.

16 Duke Energy Corporation, 2016 Form 10-K, p. 12.

17 Duke Energy Corporation, 2015 Annual Report, p. 11.

energy – not their share of nameplate capacity. Nevertheless, some data sources only show nameplate capacity, which is often cited when discussing progress toward adding renewable energy sources to the grid.

Q. HOW DOES DUKE'S PROGRESS IN CONNECTING SOLAR IN OTHER STATES COMPARE TO NORTH CAROLINA?

A. The following table[18] compares pending solar projects (as of March 2017) including both utility-owned projects and independent power producers: BEGIN CONFIDENTIAL

[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]				
[redacted]				
[redacted]				
[redacted]				
[redacted]				
[redacted]				[redacted]

18 Duke's response to NCSEADR2-9(f), PURPA Solar Penetration as of 03.13.17.xlsx.

[redacted] END CONFIDENTIAL in North and South Carolina (both have adopted similar standard offer QF tariffs) compared with the other states, where solar projects are more likely to be utility-owned or negotiated.

The following table[19] shows analogous data for the size of the pending projects:

BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL

19 Duke's response to NCSEADR2-9(f), PURPA Solar Penetration as of 03.13.17.xlsx.

Q. HOW SIGNIFICANT IS THE EXISTING AND PENDING SOLAR CAPACITY RELATIVE TO OTHER ENERGY SOURCES?

A. Solar is still a relatively minor source of energy, and is expected to remain so for the near term. The summer nameplate capacity of DEC's non-solar generating units in North Carolina (including Nantahala Power & Light hydroelectric generation) totaled 20,270 MW as of March 30, 2016.[20] On the same date, DEP's analogous summer nameplate capacity totaled 12,873 MW,[21] bringing the combined total for both systems to 33,247 MW of non-solar capacity. The capacity is even higher during the winter months: 21,028 for DEC and 13,971 for DEP, with a combined total of 35,104, due to cooler temperatures. About half of this capacity relies on fossil fuels (coal and natural gas), while approximately 30% is nuclear. Approximately 10% is hydro (including pumped storage units, which require electrical energy from other fuel sources in order to function).

In contrast, in its 2016 IRP, DEC estimated it will have just 735 MW of solar nameplate capacity connected to its system in 2017, growing to 2,168 MW in

20 DEC response to NCSEADR1-d, N.C.U.C. Docket No. E-100, Sub 147.

21 DEP response to NCSEADR1-d, N.C.U.C. Docket No. E-100, Sub 147.

2031.[22] Similarly, DEP estimated it would have 1,710 MW of solar nameplate capacity connected to its system in 2017, growing to 3,270 MW in 2031.[23]

Duke also developed "High Renewables" scenarios, which considered the potential impact of high carbon prices, increased renewable mandates, and other factors.[24] In the "High Renewables" scenarios, by the year 2031 connected solar nameplate capacity was projected to increase to 5,062 (DEP) plus 2,957 (DEC) for a total of 8,019.[25] Duke also developed "Low Renewables" scenarios, which considered the potential impact of "lower avoided costs and/or less favorable PURPA terms.[26] Under this scenario, by the year 2031 solar nameplate capacity would grow to just 2,618 MW (DEP) plus 1,932 MW (DEC) for a total of 4,550 MW of solar connected to the system.[27]

However, none of these solar nameplate figures, or the 1,600 MW of third-party developed solar connected to DEC's and DEP's grid in North Carolina, or the 4,900 MW of potential projects progressing through the interconnection

22 Duke Energy Carolinas, LLC, 2016 Integrated Resource Plan, N.C.U.C. Docket No. E-100, Sub 147 ("DEC 2016 IRP"), Table 5-A.

23 Duke Energy Progress, LLC, 2016 Integrated Resource Plan, N.C.U.C. Docket No. E-100, Sub 147 ("DEP 2016 IRP"), Table 5-A.

24 DEC 2016 IRP, p. 26.

25 DEC 2016 IRP, Table 5-B; DEP 2016 IRP, Table 5-B.

26 DEC 2016 IRP, p. 26.

27 DEC 2016 IRP, Table 5-C; DEP 2016 IRP, Table 5-C.

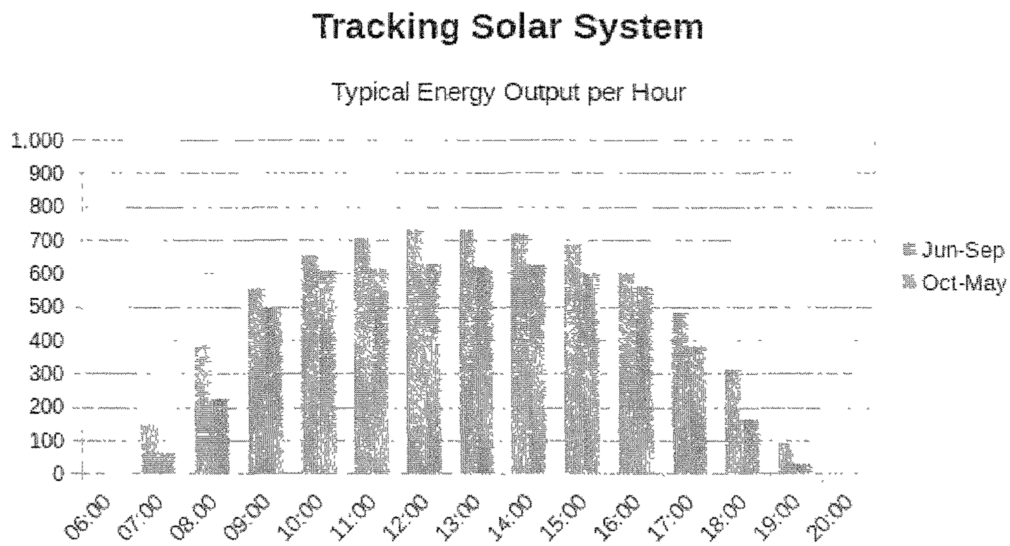
queue[28] can be directly compared to the nameplate capacity of other types of generation.

Q. WHY CAN SOLAR NAMEPLATE CAPACITY NOT BE DIRECTLY COMPARED TO OTHER TYPES OF GENERATING UNITS?

A. Solar energy output is almost never equal to the nameplate capacity. Output varies with the sun's movement, which varies in a predictable manner with the time of day and time of year. However, solar output is also affected by cloud cover, which is less predictable. In general, solar facilities have less capacity during the winter, because the sun is lower in the sky, and because cloud cover tends to be heavier and more frequent.

The following graph illustrates this pattern, using a data set in which the maximum hourly output of 1,000 MWh only occurred during a few hours of the year.

28 Yates Direct, p. 6.



The orange bars show the average hourly output during June through September, and the blue bars show the analogous average hourly output during October through May. As this graph illustrates, the electrical output follows a smooth and predictable pattern once the data is averaged across multiple days. However, it is also tends to be significantly less than its nominal nameplate capacity. The extent of the discrepancy varies depending on the technology (tracking versus fixed) as well as the time of day and day of the year.

The QF is only paid for actual energy sent to the grid and is only paid for capacity to the extent it provides energy during the limited "On Peak" hours which the utility specifies in its tariff. The theoretical nameplate capacity has no direct relevance to the amount paid by ratepayers, or the amount received by solar QFs for the use of their generating capacity; these are strictly a function of the energy provided to the utility during the On Peak hours specified in the utility's tariff.

Q. HAS DUKE PROVIDED SOME ESTIMATES OF SOLAR CAPACITY THAT CAN BE MORE DIRECTLY AND MEANINGFULLY COMPARED TO OTHER TYPES OF GENERATION?

A. Yes. Duke developed some projections for its IRP which can be very helpful in understanding the complications involved with using nameplate capacity, and drawing conclusions about the relative significance of solar capacity compared to nuclear, fossil and hydro capacity. In these projections, Duke used on 5% of nameplate capacity for the winter season, which it estimates is the fraction of solar nameplate capacity that would be generated "in the early morning hours around 7:00 a.m, when solar basically has little to no output."[29] It developed analogous data for the summer using a 46% factor, which it explained as follows:

> Solar resources contribute approximately 45% (46% for DEC and 44% for DEP) of their nameplate rating at the

29 Direct Testimony of Glen Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Snider Direct"), p. 27.

> time of the summer peak, which occurs in afternoon hours.[30]

In the following tables, I present Duke's solar capacity estimates, although I think the 5% figure for the winter might be too low. Solar facilities produce rapidly increasing amounts of energy from the moment the sun rises over the horizon, and solar output often averages more than 5% of nameplate capacity during the two-hour block from 7 a.m. until 9 a.m. – which is when the greatest need for peak capacity exists in the winter season. I will discuss this time period in greater detail later my testimony, in the context of the peak and off peak QF rates.

As shown below, Duke projects that solar capacity connected to the grid in 2017 will be less than 3% of its total 2016 nuclear, fossil, and hydro capacity.

2017 Net Solar Capacity
Compared to 2016 Total Capacity[31]

	Low Solar	**Base**	**High Solar**
Winter – 2017	0.35 %	0.35 %	0.77 %
Summer – 2017	3.28 %	3.28 %	3.46 %
Average – 2017	2.69 %	2.69 %	2.84 %

30 Snider Direct, p. 29.

31 Solar MW Contribution to Peak from DEC and DEP 2016 IRPs, Tables 5-A, 5-B, 5-C, divided by Coal, Nuclear, Combined Cycle, Combustion Turbine, Duke Hydro and NP&L Hydro capacity from DEC and DEP Responses to NCSEA DR1-d, Docket No. E-100, Sub 147.

As more solar QFs are completed and connected to the grid, solar energy is expected to become an increasingly important part of DEC and DEP's energy mix. This is reflected in the fact that Duke projects net solar capacity to roughly double or triple by 2031, as shown below:

2031 Net Solar Capacity Compared to 2016 Total Capacity[32]			
	Low Solar	**Base**	**High Solar**
Winter – 2031	0.65 %	0.77 %	1.14 %
Summer – 2031	6.14 %	7.33 %	10.79 %
Average – 2031	5.04 %	6.02 %	8.86 %

However, even under the fastest growth scenario, in 2031 solar will still be less than 9% of Duke's existing nuclear, fossil and hydro capacity.

32 Solar MW Contribution to Peak from DEC and DEP 2016 IRPs, Tables 5-A, 5-B, 5-C, divided by Coal, Nuclear, Combined Cycle, Combustion Turbine, Duke Hydro and NP&L Hydro capacity from DEC and DEP Responses to NCSEA DR1-d, Docket No. E-100, Sub 147.

Q. SHOULD THE COMMISSION ADOPT LESS FAVORABLE PURPA TERMS IN ORDER TO SLOW THE GROWTH IN SOLAR?

A. No, although this seems to be the Utilities' preference. Duke describes the recent growth in solar as both "unprecedented" and "unconstrained." Both Utilities' witnesses expressed concerns about challenges they face in trying to adapt to having more solar in their generation mix:

> This unprecedented growth in interconnected and proposed solar generation in just the past few years has ...created challenges that put our State at a crossroads.[33]

However, it is important to keep things in perspective: growth in solar production has long been the goal of public policy makers in North Carolina and elsewhere. One of the dilemmas policy makers in the state and elsewhere have long been confronted with is the reality that – absent tax incentives – solar and other sustainable technologies appeared to have higher life cycle costs than traditional energy sources like coal and oil. This perception of high costs created a vicious circle, which made it difficult for society to gain the benefits of reducing reliance on fossil fuels, and increasing the use of renewable energy sources.

High costs often limited sustainable technologies to "niche" status and blocked them from achieving mass commercial scale. In turn, the lack of

33 Yates Direct, p. 6.

commercial activity kept costs high, because (1) economies of scale in the manufacturing process were not being fully achieved, (2) too few firms were moving down the learning curve gaining the experience and skills needed to squeeze precious dollars out of the installation process, and (3) there was a general lack of opportunity (industry-wide) to observe and learn from experience, to identify "best practices" and to find solutions to difficulties.

The need to break this vicious circle was one of the fundamental reasons why Renewable Portfolio Standards, tax incentives, and other government policies have been widely adopted. In the case of solar energy in particular, it is obvious the sun provides an incredibly abundant energy source, so there is widespread agreement that we need to figure out how to commercialize the process of converting solar energy into electricity so that it will cost no more than (and eventually much less than) other energy sources. This rationale lies at the core of PURPA, as well as the many tax incentives and other policies which have been adopted by government policy makers in an attempt to break out of the vicious circle and initiate the process of bringing costs down below the level of other traditional energy sources.

In North Carolina, the solar industry is starting to break out of this vicious circle. QFs are delivering more and more solar energy at prices that have been set equal to the incremental cost of natural gas and coal fueled energy. It would be a mistake to slam on the brakes just as commercial mass scale is beginning to be achieved, because this growth is bringing new "challenges."

The challenges faced by the Utilities are real, and the care should be taken to investigate these challenges, and develop appropriate policy responses to ensure they do not become more serious. But, fundamental changes like the shift toward renewable energy normally bring with them many different technical, economic and other challenges. There is no reason to let these challenges slow the growth of solar – which could block the emergence of a virtuous circle of rapid growth, rapid movement down the learning curve, and rapid improvements in economic efficiency.

Q. HAVE THE UTILITIES RECOGNIZED THE BENEFITS TO SOCIETY FROM "UNCONSTRAINED" GROWTH IN SOLAR PRODUCTION?

A. No. The focus of their testimony seems to be almost entirely on the technical difficulties and operational challenges they are facing as a result of having more and more solar energy injected onto their systems, rather than the benefits to society that result from this rapid growth.

In response to these challenges, all three Utilities are asking the Commission to reverse long-standing Commission policies concerning PURPA, impose higher risks on QFs and lower QF rates below long run incremental costs. This is at least tacitly acknowledged in this passage from DNCP's testimony:

> It is true that several proposals similar to those that the Company has proposed in this proceeding were not accepted by the Commission in the 2014 Avoided Cost Case. However, as I will explain further in this testimony, since the 2014 Avoided Cost Case, the landscape of QF development in the Company's North Carolina service area has changed significantly. Given these changes, [DNCP] believes that it is imperative that the Commission reconsider these issues on a prospective basis for new solar QF development, and evaluate the Company's proposed revisions to its standard avoided cost rate schedules and contracts to adapt to those changing circumstances.[34]

If the Commission adopts these proposed responses to the challenges the Utilities are facing, it will create a more leisurely pace of solar expansion (more like what is happening in Louisiana or Mississippi), and it will lessen the chances of moving from a vicious circle of high costs and little experience gained, to a virtuous circle of rapid growth, swift movement down the learning curve, and larger cost reductions.

Q. HOW DO THE UTILITIES DESCRIBE THE POLICY CHOICES IN FRONT OF THE COMMISSION?

A. Mr. Yates conveyed the essence of Duke's position in his testimony:

> North Carolina is at a critical crossroads regarding the integration, development, and customer costs of renewable

34 Gaskill Direct, p. 5.

> generation. This crossroads is particularly critical for solar generation.[35]

> ...current regulatory and economic drivers necessitate a comprehensive review of the Commission's PURPA policies to ensure the long-term viability and integration of additional solar and other renewable resources for the benefit of our State and our customers.[36]

In general, I think it's fair to say DEC, DEP, and DNCP see the disparity between solar growth in North Carolina and in other states rather negatively, rather than positively:

> Existing policies, which have resulted in unconstrained growth in solar generation, have created a distorted marketplace for solar projects that have resulted in artificially high costs that are inevitably passed onto North Carolina residents, businesses, and industries, while potentially degrading operation of the Companies' electric systems. These policies have created a larger and more rapid utility-scale solar growth and now need to be reevaluated to allow for a smarter, more sustainable and economic approach.[37]

DNCP does not describe the situation in quite such stark terms, but nevertheless much of its testimony focuses on negative aspects of the growth, rather than its societal benefits. These passages from DNCP witness Gaskill's testimony capture the general tenor:

35 Yates Direct, p. 4.

36 Yates Direct, p. 10.

37 Yates Direct. p. 6.

> The influx of distributed solar generation onto DNCP's North Carolina system is now adversely impacting our system operations in this State.[38]

I will discuss many of these concerns, and I will respond to specific proposals offered by the Utilities in reaction to these concerns, at various points throughout the remainder of my testimony.

Section 3: Rate Comparisons

Q. HAVE YOU COMPARED THE QF RATES PROPOSED IN THIS CASE TO THE RATES THAT WERE APPROVED AT THE END OF THE LAST BIENNIAL PROCEEDING?

A. Yes. Duke's most recently approved QF rates were developed pursuant to a settlement agreement amongst the Utilities, the Public Staff, NCSEA, and the Southern Alliance for Clean Energy ("SACE").[39] Analogous rates were submitted by DNCP on February 2, 2016 as a compliance filing. Before presenting my numerical comparisons, it is helpful to mention some structural differences between those tariffs ("2014 tariffs") and the ones that have been submitted in this proceeding.

38 Direct Testimony of J. Scott Gaskill on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Gaskill Direct"), p. 7.

39 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 140, March 10, 2016.

First, the Utilities' 2014 tariffs offer QFs four different rate options: a variable rate, a 5-year levelized rate, a 10-year levelized rate, and a 15-year levelized rate. DEC and DEP proposed to eliminate half of these options, forcing the QF to choose between a variable rate that does not include any payment for capacity and a 10-year rate that does. DNCP proposes to eliminate the 15-year option, limiting QFs to rates that do not extend beyond 10 years.

Second, the DEC and DEP proposed tariffs do not specify the rates that will be paid each year during the 10-year term, unlike the 2014 tariff which provides a fixed rate for the entire 10- or 15-year term. Instead, the energy component is subject to change every two years. Furthermore, the tariff does not include a formula or index, or any other information which would limit the magnitude of future rate changes, or which could be used by lenders and investors to estimate the actual rate that will be paid (what revenue the QF will receive) after the first two years.

Third, the Utilities' 2014 tariffs are available to certain QFs up to 5 MW in size; DEC, DEP, and DNCP's proposed tariffs are limited to QFs up to 1 MW.

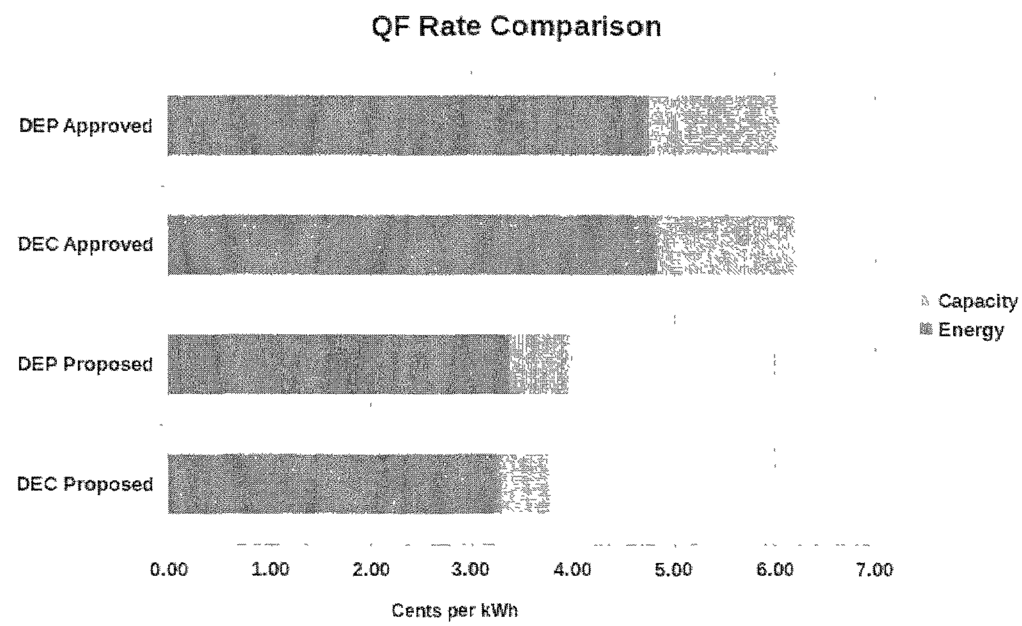
All of these proposals have the effect of increasing the risks faced by QFs, and making it more difficult to finance QF projects. They also make it harder to provide the Commission with meaningful comparisons between the current and proposed rates, since any comparison will necessarily involve some degree of mismatching.

I have tried to deal with this problem by comparing the current 15-year rates to the proposed 10-year rates. Of course, this is not a perfect match, since the proposed rates are only available to a 1 MW QF, while the current rates can be used with projects of up to 5 MW, and the PPA terms and durations are not identical. However, this provides the closest, most realistic comparison that is feasible, since it compares the least risky option which also generates the highest "bankable" revenue under the current tariff to the least risky option which generates the highest "bankable" revenue under the proposed tariff. To further simplify and improve the comparisons, I compared the rates on a composite or weighted average basis, as they apply to a typical solar facility.

More specifically, I looked at the rates applicable during each hour of each day of the year, and applied them to the volume of energy which can reasonably be expected from a typical QF solar facility to determine the total payments that would be received by the QF. The total payments were then divided by the total kWh which were expected to be produced by the QF, in order to calculate an overall composite rate per kWh. This procedure took into account how the Summer and Non-Summer seasons are defined, as well as how the peak and non-peak time periods are defined in each of the tariffs.

Q. WHAT IS REVEALED BY THIS COMPARISON?

A. This composite analysis demonstrates that the proposed QF rates are far lower than the current rates. If the proposed tariffs are approved, it will be much more difficult to finance QF projects, as shown in the following graph:



The current DEP and DEC rates differ just slightly, primarily due to differences in their generating facilities and load patterns. In contrast, both sets of proposed rates are significantly lower, as shown in the following tables:

Difference in QF Rates: DEP Current versus Proposed			
	Energy	Capacity	Total

DEP – Current	4.767 cents	1.303 cents	6.070 cents
DEP – Proposed	3.406 cents	0.573 cents	3.979 cents
Difference	-1.360 cents	-0.730 cents	-2.091 cents
Percent Difference	-28.5%	-56.0 %	-34.4 %

Difference in QF Rates: DEC Current versus Proposed			
	Energy	Capacity	Total
DEC – Current	4.850 cents	1.386 cents	6.236 cents
DEC – Proposed	3.315 cents	0.478 cents	3.793 cents
Difference	-1.535 cents	-0.908 cents	-2.443 cents
Percent Difference	-31.6 %	-65.5 %	-39.2 %

As shown in the above tables, under the proposed tariff, QFs will receive 34.4% (DEC) or 39.2% (DEP) less revenue than if the project were eligible for the 2014 rates. These are very substantial revenue reductions, which would make it harder for them to obtain financing. Along with structural changes to the standard offer which increase the risks facing QF projects, these rates will have a substantial, negative impact on QF investment in the state.

Q. HOW DO THE CURRENT QF ENERGY RATES COMPARE TO DUKE'S AVERAGE FOSSIL FUEL COSTS?

A. The QF energy rates in the 2014 tariff are about a penny higher per kWh than Duke's average fossil fuel costs during the 12 months ending December 2015,[40] as shown in the following table:

Duke 2014 – 2028 QF Energy Rates versus 2015 Average Fuel Costs		
	DEP	**DEC**
2014 – 2028 QF Rate	4.767 cents	4.850 cents
2015 Average Fuel Cost	3.670 cents	3.444 cents
Difference	1.097 cents	1.406 cents

Q. IS A DIFFERENCE OF THIS TYPE TO BE EXPECTED?

A. Yes. There are at least two reasons to expect QF rates to be higher than average fossil fuel costs.

First, the QF rates are levelized, so they are based upon fuel prices that are forecasted into the future. In other words, the QF energy rates reflect a combination of lower fuel costs in the early years of the contract and higher fuel costs in the later years of the contract. Any comparison that only looks

40 DEC and DEP Monthly Fuel Reports pursuant to NCUC Rule R8-52, February 3, 2016.

at average fossil fuel costs in the early years will necessarily be lower than the levelized QF rates. By the same token, analogous comparisons that are performed during the latter part of the 15-year period can be expected to show the opposite pattern: the levelized rates will be less than fossil fuel costs incurred in those years.

Second, under the Peaker Method, the QF rates are based upon marginal, not average fuel costs. The Peaker Method assumes marginal fuel costs will be higher than average fuel costs, and it assumes the difference will be sufficient to compensate for the higher cost of building and operating baseload generating units compared to the capacity-related costs of a peaker.

Q. CAN YOU EXPLAIN IN MORE DEPTH WHY THE QF ENERGY RATES DEVELOPED USING THE PEAKER METHOD ARE SUPPOSED TO BE HIGHER THAN AVERAGE FUEL COSTS?

A. Yes. This goes all the way back to the historical roots and theoretical underpinnings of the Peaker Method. In its 1994 Biennial Avoided Cost Order, the North Carolina Utilities Commission explained the Peaker Method as follows:

> The peaker approach to avoided costs used by both Duke and Progress Energy in the biennial proceedings, is based on a method developed by National Economic Research Associates, Inc. (NERA) and described in detail in the "Grey" series of publications 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. It is one of four marginal costing methodologies developed in the "Electric Utility Rate Design Study" part of the series (topics 1.3 and 4).

According to the theory underlying the Peaker Method, the capital cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system should produce the utility's full avoided cost of building and operating a new baseload generating plant, assuming the utility's generating system is operating at equilibrium with an efficient mix of baseload, intermediate and peaking plants. This result is supposed to be achieved by using relatively high energy costs from the most costly unit operated during any given hour. In essence, the avoided energy cost estimates used in creating the QF rates are based on decreasing the output of whatever unit is operating "at the top of the stack" by 100 MW during any given hour.

The premise behind the Peaker Method is that the cost of operating the unit at the top of the stack will generally be higher than the cost of operating units farther down the stack (because, in theory, those have lower heat rates and lower fuel costs). If combustion turbines with poor heat rates are operating at the top of the stack during enough hours of the year, this difference in fuel costs will be sufficient to compensate for the additional capital costs of a baseload unit relative to a peaker.

Stated another way, the Peaker Method does not provide explicit recovery of the higher fixed costs of a combined cycle or other baseload plant, relative to a peaker. However, those higher fixed costs are supposed to be implicitly recovered by calculating higher avoided energy costs that are derived exclusively from the "top of the stack." By combining higher energy costs with lower capital costs, the results of the Peaker Method are supposed to be equivalent to the results of using the Proxy Unit method to estimate the full avoided cost of building and operating a new baseload unit.

> According to the theory underlying the Peaker Method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant. This is because the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.[41]

This aspect of the Peaker Method can lead to confusion when comparing the cost of QF power, particularly when compared to the cost of nuclear power,

41 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 100, September 29, 2005, p. 17.

but it also is relevant to comparisons with coal and natural gas fired baseload units. Although it can lead to confusion, this additional complexity is one of the main advantages of the Peaker Method: it allows costs to be computed on an hour-by-hour basis.

In fact, the original purpose of the Peaker Method was specifically to help develop time-differentiated prices based upon "marginal cost." This is clear from both the titles, and the contents of NERA's Grey Books. One of the books, covering Topic 1.3, was called A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States. The other book, covering Topic 4, was called How to Quantify Marginal Costs.

Hour-by-hour granularity was achieved by combining the levelized cost of building and owning a new peaking plant (rather baseload) with the marginal running costs of the entire system, separately calculated for each hour of the day and each day of the year. As explained in the Grey Books:

> During the day, the marginal cost will generally be the running cost of an intermediate machine, and at peak it will be the running cost of a peaking machine. This is the familiar dispatch cost which is routinely calculated for interutility sales. At peak, however, we also encounter the need to expand capacity, and each hour at peak should also be charged the cost of expanding capacity. The appropriate cost is, however, the marginal cost of capacity, the

> machine that will meet loads of shortest duration in the least cost way. It will generally be a peaking plant.[42]

> [T]he price of running cost and capital cost of a peaker at the peak will exactly recover the total costs of adding and running the peaking plant.[43]

> In the long run, after capacity has been adjusted, the marginal cost is the cost of energy plus the cost of capacity at peak.[44]

Q. WILL THE DIFFERENCE BETWEEN AVERAGE AND MARGINAL FUEL COSTS ALWAYS FULLY COMPENSATE FOR THE HIGHER CAPITAL COST OF A BASELOAD PLANT?

A. No. While this is the intent of the Peaker Method, there is no guarantee that QFs will be paid the full avoided cost of a baseload plant. In practice, it depends on how often the utility's combustion turbines are actually dispatched and other real-life factors which do not necessarily precisely match the assumptions used in developing the theory. As a result, in practice the difference between average and marginal cost may not be sufficient to achieve this intended result. While the avoided energy cost estimates and avoided capacity cost estimates are supposed to provide total compensation that is

42 A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States, p. 57.
43 A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States, p. 63.
44 How to Quantify Marginal Costs, p.37.

equivalent to the full avoided cost of building and operating a new baseload generating plant – this does not necessarily happen every time.

In fact, because of the "lumpiness" of baseload capacity additions, changes in relative price levels for different types of fuel and other factors, marginal fuel costs may not always exceed average fuel costs by a wide enough margin to fully compensate for the cost of building and operating a new baseload generating plant.

Q. HAVE YOU COMPARED DUKE'S MARGINAL FUEL COSTS TO ITS AVERAGE FOSSIL FUEL COSTS?

A. Yes. I compared the same average fossil fuel data discussed earlier, with DEC and DEP's hourly marginal costs during 2015.[45] To make a direct comparison, I weighted the marginal cost in each hour by the volume of energy during that hour. Thus, the higher marginal costs that are incurred during daytime hours were given more weight than the lower costs that are incurred at night. This is the most relevant comparison, since the average fuel cost data is conceptually similar. The data can be seen below:

Duke Marginal Fuel Costs versus Average Fuel Costs

45 Duke's response to NCSEADR1-11, 2015 hourly marginal costs.xlsx.

	DEP	DEC
2015 Marginal Fuel Cost	3.494 cents	3.493 cents
2015 Average Fuel Cost	3.670 cents	3.444 cents
Difference	-0.176 cents	0.049 cents

I then analyzed the marginal cost data using the On Peak and Off Peak time periods used in the QF tariffs. That comparison is summarized below:

Duke Marginal Fuel Costs versus Average Fuel Costs		
	DEP	**DEC**
2015 Marginal Fuel Cost – On Peak	3.724 cents	3.723 cents
2015 Marginal Fuel Cost – Off Peak	3.264 cents	3.263 cents
2015 Average Fuel Cost	3.670 cents	3.444 cents
Difference – On Peak	0.054 cents	0.279 cents
Difference – Off Peak	-0.406 cents	-0.181 cents

In general, this analysis suggests Duke's marginal fuel costs are currently very similar to its average fossil fuel costs. Since this is a snapshot of a single year, no definitive conclusions can be reached, but these comparisons suggest Duke's marginal fuel costs may not, in actual practice, be far enough above its average fuel costs to cover the full incremental cost of a natural gas or coal-fired baseload plant. In other words, this data suggests the Peaker Method is providing low-end estimates of avoided costs, since the marginal fuel costs are so close to the system average fossil fuel costs.

Q. WHY IS THIS?

A. Although Duke owns many peaking plants, they are rarely operated. As discussed earlier, the theory underpinning the Peaker Method assumes combustion turbines will be operating at the "top of the stack" during many hours of the year. The more hours there are when high marginal fuel costs are being incurred, the more opportunity there is for the gap between marginal and average fuel costs to be large enough to be equivalent to the difference between the capacity cost of a new baseload plant and a new peaker.

In Duke's case, there are many hours of the year when the generating unit that is actually operating at the "top of the stack" is not a combustion turbine with high fuel costs, but instead it is a baseload coal or combined cycle unit, that has significantly lower fuel costs.

This can be confirmed by analyzing the Prosym output that was used to develop the proposed rates. For instance, DEC's Proysm runs show a combustion turbine operating at the "top of the stack" during less than BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL in 2017.[46] While combustion turbines operate a little more frequently during some other years, in none of the years are they operated anywhere near the theoretical "cross-over" point that was used to support the Peaker Method.[47]

Q. IF PEAKERS ARE RARELY ON THE MARGIN, WHAT IS ACTUALLY OPERATING AT THE "TOP OF THE STACK"?

A. Coal units are expected to be operating at the margin during BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL hours during 2017.[48] In fact, coal units are expected to be operating at the top of the stack during BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL of the on-peak hours and an even higher percentage of the off-peak hours throughout 2018 – 2026.[49]

The following graphic shows the generation sources that Proysm shows operating at the margin during on-peak hours:[50] BEGIN CONFIDENTIAL

46 DEC response to the second data request of the Public Staff ("PSDR2"), request 18 ("PSDR2-18), StationGroup Hours.xlsx.

47 The breakeven or "cross-over" point (where fuel cost savings justify building a combined cycle unit instead of a peaker) depends on the heat rate of the combined cycle and combustion turbine units, fuel prices and other factors. The benchmark cost analysis described in detail later in my testimony indicates a cross-over point in the vicinity of 4 to 5 hours per day. For shorter duration loads, the higher fixed cost of the combined cycle unit outweighs the higher variable fuel cost of the combustion turbine.

48 DEC response to PSDR2-18, StationGroup Hours.xlsx.

49 DEC response to PSDR2-18, StationGroup Hours.xlsx.

50 DEC response to PSDR2-18, StationGroup Hours.xlsx.

[redacted]

END CONFIDENTIAL. Since at present baseload units, rather than peaking units, are expected to be operating at the "top of the stack" during so many hours, there is reason to question whether the marginal energy costs developed by Prosym actually exceed the fuel cost of a new baseload plant to the degree initially envisioned by the theoreticians who developed the Peaker Method, many years ago.

> According to the theory underlying the Peaker Method ...the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will ...equal the avoided cost of a baseload plant, despite the fact that the

> capital costs of a peaker are less than those of a baseload plant.[51]

In essence, when the Peaker Method was developed, it was assumed the marginal units would have high fuel costs, and as a result the system running costs would be much higher than the fuel costs of a new baseload plant:

> Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker[52]

In this proceeding, however, DEC and DEP's Prosym model runs show baseload coal and combined cycle plants being operated at the margin during BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL during 2017-2026.[53] Consequently, there is reason to doubt whether the marginal energy costs produced by Prosym are high enough to be fully consistent with the theory underlying the Peaker Method. In other words, we can't be confident that the Prosym output, when combined with the capital cost of a combustion turbine, will equal the full long run incremental cost of a new baseload plant – as it should be.

51 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 100, September 29, 2005, p. 17.

52 Id.

53 DEC response to PSDR2-18, StationGroup Hours.xlsx.

Q. HAVE YOU DEVELOPED SOME DATA THAT FURTHER CLARIFIES THIS ISSUE?

A. Yes. I developed some benchmark avoided cost estimates using the Proxy Unit method that can shed further light on this issue. I provide a more detailed discussion of these cost estimates in the next section of my testimony, including an explanation of my methodology and assumptions. For the moment, it is sufficient to briefly mention a few issues.

When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind. However, it is important to note that, under the Peaker Method, avoided energy costs are also supposed to include some fixed capital-related costs. Thus, the distinction between capacity-related costs and energy-related costs is not identical to the distinction between fixed costs and variable costs, nor is it identical to the distinction between capital-related and operating expense-related costs.

Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion was limited to the annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant were treated as "energy-related." This disaggregation is widely accepted – as I mentioned earlier, it is fundamental to the theoretical underpinnings of the Peaker Method.

Disaggregating fixed costs in this manner is particularly useful in understanding the economics of a nuclear unit. The great majority of the capital investment in a nuclear plant is not attributable to the goal of meeting peak capacity (although a nuclear plant also provides capacity for achieving that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs. The uranium used to fuel a nuclear plant tends to be less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using this technology. No one would invest in a nuclear unit just to provide capacity during peak hours.

In general, the added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

Q. WHAT IS THE ANNUAL FIXED COST PER KW FOR EACH OF THESE TECHNOLOGIES?

A. The benchmark levelized annual cost estimates in 2017 dollars are summarized in the following table:

Cost per kW/Year	Nuclear	Combined Cycle	CT
Capacity Related	$ 87.12	$ 87.12	$ 87.12
Energy Related	605.61	51.78	0.00
Total	$ 692.72	$ 138.90	$ 87.12

Q. CAN THESE NUMBERS BE CONVERTED INTO CENTS PER KWH?

A. Yes. However, annual fixed costs per kWh vary widely, depending on how many hours a unit is assumed to operate. For instance, I have assumed a nuclear unit will be dispatched at the bottom of the generating stack, and its energy-related costs will be recovered during all 8,760 hours per year. With this assumption, the capacity-related fixed costs of the nuclear unit are approximately one cent per kWh ($87.12/8760), and the energy-related fixed costs are 6.91 cents per kWh.

I assumed the combined cycle unit would be dispatched after the nuclear unit, and would not be operated as many hours, while the combustion turbine would be dispatched last, and operate the fewest hours. For certain purposes, I assumed annual fixed costs of the combined cycle unit would be recovered over 5,110 hours per year[54] but I also looked at other assumptions.

Similarly, I assumed the combustion turbine would be dispatched last, since it has the highest variable costs. For some comparative purposes, I assumed the CT would be dispatched approximately 4 hours per day, or 1,460 hours per year, but I also considered other assumptions.

Q. CAN YOU EXPLAIN WHY DISPATCH HOURS ARE IMPORTANT AND CAN VARY?

A. Yes. Historically, coal plants were built with the expectation of being dispatched after nuclear plants and before combined cycle plants, which primarily thought of as intermediate or mid-range plants. Combustion turbines were classified as peakers and dispatched last.

Generating plants tend to be dispatched more frequently when they are first added to the system and less frequently as they get older, as newer, more fuel-efficient units are introduced to the resource stack. Hence, the actual dispatch

54 Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the combined cycle unit will be dispatched approximately 58% of the time. I recognize this is less than the actual dispatch factor that would be anticipated for a new combined cycle plant under current conditions. Natural gas prices are currently very low, while the system includes many coal fired plants that are being dispatched after combined cycle units, which was not anticipated at the time the coal plants were built. Nevertheless, a 58% dispatch factor is an appropriate assumption in this particular context, since this is similar to a typical overall system load factor.

sequence will vary depending on the age (and heat rate) of each specific plant. Changes in relative fuel prices can also cause the dispatch order to change.

For instance, during 2015 and 2016 natural gas prices were very low. This led to coal plants being dispatched higher in the generation stack (after newly built gas-fired combined cycle plants), even though they have higher capital costs. Some coal plants would never have been built, if the planners had known that natural gas prices were going to be as low as they have been recently. Ratepayers continue to pay the full cost of these baseload plants, even though they are being dispatched later in the stack, and their fixed costs are therefore being spread over relatively few hours. As a result, their effective cost per kWh is higher than was originally anticipated when their construction was planned. Since the actual number of hours any given plant will be dispatched can vary as fuel prices change, and may decline as newer, more efficient units are added to the system, it can be useful to see how the fixed costs per kWh will vary, depending on how many hours the unit is assumed to operate.

Q. WHAT IS THE FIXED COST PER KWH OF THESE TECHNOLOGIES?

A. The combined cycle plant has a capacity-related costs could theoretically be as low as .99 cents per kWh for capacity and .59 cents per kWh for energy, totaling 1.58 cents per kWh if it were dispatched 100% of the time it is available. The capacity-related cost would likely be around 1.70 cents per kWh and the energy-related costs around 1.01 cents per kWh, for a total of 2.71 cents per kWh if it were dispatched at roughly the same rate as a typical overall system load factor (58%), as shown in the table below:

Levelized Fixed Costs per kWh

Annual Dispatch Rate	**CC - Capacity**	**CC - Energy**	**CT - Capacity**
100%	0.99 cents	0.59 cents	0.99 cents
90%	1.10 cents	0.66 cents	1.10 cents
75%	1.33 cents	0.74 cents	1.33 cents
58.3%	1.70 cents	1.01 cents	1.70 cents
29.2%	3.41 cents	2.03 cents	3.41 cents
16.7%	5.97 cents	3.55 cents	5.97 cents
5%	19.89 cents	11.82 cents	19.89 cents

The CT and CC capacity-related costs are identical by definition (the portion of the combined cycle unit's total fixed costs that is categorized as capacity-related is derived from the CT's capacity related costs).

The difference between the fixed cost of a combined cycle plant and the fixed cost of a combustion turbine will be at least .66 cents per kWh (if the plant is dispatched 90% of the time throughout its entire economic life), and more likely it will be around 1.01 cents per kWh. These figures provide some useful perspective in judging the reasonableness of the QF rates.

These fixed costs are paid by retail customers when power is generated by the utility using generating units that are included in its rate base. These types of costs can be avoided when power is purchased from a QF instead, and they should therefore also be encompassed within the QF rates, as part of the avoided energy costs. Under the Peaker Method, the implicit assumption is that marginal energy costs will exceed average fuel costs by an amount sufficient to recover this additional penny. Considering that marginal fuel costs have recently been much closer to the system average fossil fuel costs, it is doubtful this intended result is being achieved.

Q. WILL YOU PLEASE RESTATE THE CONCLUSION YOU REACHED FROM ALL THIS DATA?

A. Given the theory behind the Peaker Method, the calculated marginal cost-based avoided energy rates should be approximately .66 to 1.01 cents per kWh higher than the system average fossil fuel costs. Since the recently observed gap between marginal and average costs is much narrower than this, the Peaker Method is currently yielding relatively low avoided energy cost estimates which do not fully compensate for the full cost of building and operating a combined cycle plant. This is an important piece of evidence the Commission should keep in mind when deciding how to resolve the issues in this proceeding.

Q. DID YOU ALSO LOOK AT FUEL AND OTHER VARIABLE ENERGY-RELATED COSTS?

A. Yes. Before presenting this data, it is important to keep in mind that variable costs can be difficult to deal with, because they are largely determined by future fuel prices, which are not knowable with much precision. For that reason, I developed cost estimates using several different fuel price scenarios. I will be discussing each of these scenarios, and other issues related to fuel costs, later in my testimony.

Q. HOW DO THE PER KWH ENERGY COSTS COMPARE FOR THESE THREE TECHNOLOGIES?

A. The costs vary fairly widely, depending upon the technology and long-term natural gas price scenario. Looking first at the combustion turbine, the levelized avoided energy costs (including fuel and variable operations and maintenance costs, but excluding capacity-related costs) range from less than 4 cents per kWh to more than 11 cents per kWh, as shown below:

Combustion Turbine Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢

Combustion Turbine Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2027 - 2031 Levelized	6.09 ¢	7.79 ¢	8.31 ¢	11.16 ¢

With the combined cycle plant, the sensitivity to fuel prices isn't quite as extreme, since the unit has a better heat rate (burns less fuel) and because the avoided energy costs include energy-related fixed costs, which do not vary with fuel prices, but do vary with the assumed capacity factor, as was just discussed. This greater stability can be seen in the following table, which assumes a 58% dispatch factor:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	2.94 ¢	3.83 ¢	3.59 ¢	4.23 ¢
2022 - 2026 Levelized	3.78 ¢	4.59 ¢	4.80 ¢	6.13 ¢
2027 - 2031 Levelized	4.33 ¢	5.43 ¢	5.76 ¢	7.60 ¢

The Nuclear plant is not sensitive to gas prices and the cost is largely stable over time, because most of the costs are fixed and levelized:

Nuclear Energy-Related Cost per kWh	Natural Gas Price Scenario			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	8.22 ¢	8.22 ¢	8.22 ¢	8.22 ¢
2022 - 2026 Levelized	8.35 ¢	8.35 ¢	8.35 ¢	8.35 ¢
2027 - 2031 Levelized	8.50 ¢	8.50 ¢	8.50 ¢	8.50 ¢

The combined cycle unit generally has the lowest costs and therefore in the remainder of my testimony I have primarily focused on these cost estimates. However, each technology has advantages and disadvantages. The combustion turbine tends to be more cost effective in meeting loads of short duration[55] while nuclear technology provides the greatest price stability over the very long term. This greater stability has historically proven to be an advantage for nuclear plants – even ones that encountered major schedule delays and cost over-runs ultimately became more cost effective in the latter part of their life cycle. Even troubled nuclear plants, with high construction costs, have looked better and better over time, because their construction cost was largely fixed, and the cost of alternative fuels increased greatly over the 40- to 60-year life of the plant.

55 If a generating unit is going to be dispatched less than approximately 1,700 hours a year, the benefit of the lower installed cost of the CT outweighs the burden of its higher heat rate and fuel costs.

Q. HAVE YOU COMPARED THESE BENCHMARK COST ESTIMATES TO THE CURRENT AND PROPOSED RATES?

A. Yes. This table compares the QF rates in the standard offer tariff approved in the 2014 biennial proceeding to the 2017-2021 levelized cost of the combined cycle unit:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
DEP – 2014 Rates	4.77 ¢	4.77 ¢	4.77 ¢	4.77 ¢
DEC – 2014 Rates	4.85 ¢	4.85 ¢	4.85 ¢	4.85 ¢

The amount ratepayers will pay for obtaining power from QFs under the current QF energy rates will be approximately 1 cent per kWh more than the cost of obtaining power from a new combined cycle plant, assuming the "Low" fuel prices occur. If fuel prices match the most recent EIA projection during this five-year period, or if they return to the historical trend, the amount paid for QF power at the current rates will be very similar to (or slightly lower than) the cost of using the combined cycle plant. If "High" fuel prices were to occur, the combined cycle plant will be about 1 cent costlier than the current QF rates.

In contrast, under every scenario the proposed QF rates are below the estimated long run cost of generating electricity using a combined cycle plant, and the discrepancy will be quite extreme if "High" fuel prices prevail:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
DEP – Proposed	3.41 ¢	3.41 ¢	3.41 ¢	3.41 ¢
DEC – Proposed	3.32 ¢	3.32 ¢	3.32 ¢	3.32 ¢

This next table compares the current QF rates to the 2022-2026 levelized cost of the combined cycle unit:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢
DEP – 2014 Rates	4.77 ¢	4.77 ¢	4.77 ¢	4.77 ¢
DEC – 2014 Rates	4.85 ¢	4.85 ¢	4.85 ¢	4.85 ¢

The 2014 QF energy rates are lower than the cost of obtaining power from a new combined cycle plant under every scenario, with the discrepancy increasing the more fuel prices increase. Under the "High" fuel price scenario, ratepayers will be paying less than 5 cents per kWh for power obtained from

QFs while paying nearly 9 cents per kWh for power generated by a new combined cycle plant.

Needless to say, the discrepancy would be even larger if the proposed QF rates were accepted:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢
DEP – Proposed	3.41 ¢	3.41 ¢	3.41 ¢	3.41 ¢
DEC – Proposed	3.32 ¢	3.32 ¢	3.32 ¢	3.32 ¢

Q. WILL RETAIL CUSTOMERS BENEFIT IF THE COMMISSION REDUCES QF RATES TO A LEVEL FAR BELOW WHAT IT COSTS TO OBTAIN POWER FROM A NEW COMBINED CYCLE PLANT?

A. No. Although low QF rates may be superficially appealing (on the assumption that lower QF rates will translate into lower retail rates through a fuel adjustment and purchased power mechanism), artificially suppressing QF rates does not benefit ratepayers. Any short-term benefit from low QF rates is of limited value, because low QF rates discourage QF investment, thereby reducing the amount of energy that the utility will actually obtain at the lower rates. Taken to the extreme, if QF rates are so low that no further QF investment occurs, no purchases would be made at the artificially low rates, and there would be no further savings available to flow through to retail customers.

Even if some QFs end up selling some power at the artificially low rate (e.g. they are already committed to their projects before the low rates are established), the potential benefit to retail customers will be limited, because future QF investment will be discouraged and the potential for increased pressure on the utility to operate efficiently will be lost. Instead, customers will be forced to buy more costly power generated by the utility itself. Simply stated, over the long run, retail customers are harmed by artificially low QF rates, because low rates shield utilities from competition, reducing pressures for them to minimize their costs.

Furthermore, low QF rates encourage unnecessary expansion of the regulated rate base, thereby shifting risks onto retail customers that could have been borne by QF investors instead. For example, when a new combined cycle plant is built by DEC or DEP, their customers bear nearly all of the risks associated with scheduled delays, construction cost overruns, or unexpectedly high fuel costs. Absent an extraordinary finding of imprudence, which rarely occurs, all of the risks associated with construction and operation of a utility-owned generating plant are ultimately borne by ratepayers. Even in cases where a plant is retired early, or construction is never completed, ratepayers will normally shoulder the burden of any resulting stranded costs.

In contrast, when independent power producers build plants, customers are shielded from these risks, because they only pay for power that is actually generated, and the price remains the same regardless of what delays or cost over-runs occur during construction. In sum, it is not in the public interest for the Commission to endorse unrealistically low avoided cost estimates, or to adopt excessively low QF rates. To the contrary, the public interest is best served by encouraging competition, by accurately and fairly implementing the provisions of PURPA and the associated FERC rules.

Q. ARE YOU ADVOCATING SETTING QF RATES AT THE HIGHEST ALLOWABLE LEVEL?

A. No. A middle course is preferable. Retail customers are better served by regulatory decisions that set QF rates away from these extremes, at a point that is closer to the long run incremental costs that are incurred by utilities when they build and operate their own generating plants. I believe this long-run incremental cost standard is also more consistent with the requirements of federal law. It encourages competitive entry by small power producers, without imposing a cost burden on customers, and without subsidizing QF development or running the risk of encouraging economically inefficient levels of QF investment.

Stated a little differently, the public interest is best achieved by establishing rates that leave ratepayers indifferent as to whether energy and capacity is obtained from QFs or from the utility itself under traditional rate base regulation. By setting QF rates equal to the cost of having the utility build and operate its own generating units, PURPA creates a level competitive playing field between utility-owned generation and QF power purchases. This encourages investment by QFs to the extent they believe they can operate more efficiently or at lower cost, or they are more willing to experiment with new technologies, or they are willing to accept a lower return on their investment than the one paid on comparable investments put into the utility's rate base. This creates healthy competition, which exerts downward pressures on retail rates, pressures the incumbent utilities to minimize their own costs, and benefits retail customers over the long term.

Q. YOU HAVE DEVELOPED LONG RUN COST ESTIMATES. WOULD IT BE BETTER TO FOCUS ON SHORT-TERM COSTS?

A. No. I believe the purpose of PURPA can best be accomplished by taking a long-term view of the choice between QF and utility-provided power. More specifically, I believe the concept of "indifference" and the calculation of avoided costs should generally be consistent with the full incremental cost of building and operating generating facilities over their entire economic life cycle. This is the type of cost data I have presented above, and I think it is the most appropriate standard for evaluating the ultimate impact on ratepayers.

In the electric utility industry, short-run costs are sometimes less than long-run costs, due to lumpiness of capital additions among other factors. However, ratepayers are required to bear the full long-run cost of plants that are put into the rate base. If QF rates only considered a short-run measure of costs, like variable operating costs, while ignoring other costs the utilities incur (and customers pay) in the long run, a mismatch occurs, and indifference is not achieved. Stated another way, using a short-run view of avoided costs that fails to consider the full cost of building and operating new generating plants over their economic life cycle will discriminate against QFs and discourage QF investment.

Accordingly, it has often been recognized that the appropriate measure of avoided costs is one that is equivalent to the total costs incurred when a utility builds, owns and operates new generating plants over their life cycle. Properly implemented, a long-run measure of costs ensures that QFs receive the same amount for their power as the utilities receive for power produced using their own generating plants – no more and no less.

It should also be noted that QFs typically sign long-term contracts to sell their output at "fixed or pre-specified prices" and this is type of contract is needed for them to obtain debt financing. For logical consistency, long-term contracts generally require the use of "long-term estimates of avoided cost."[56] Furthermore, FERC has clarified that under PURPA QF's are entitled to sell electricity pursuant long-term contracts with forecasted avoided cost rates.[57]

Q. WHAT CONCLUSION DID YOU REACH FROM THESE BENCHMARK COST COMPARISONS?

A. The most significant conclusion is that the long run costs the Utilities are incurring when they build and operate new combined cycle plants is in the same general range as what ratepayers have been paying for power obtained from QFs over the next five to ten years pursuant to the current approved QF tariffs. Beyond that length of time, the QF power actually costs ratepayers less than the cost of power from a new combined cycle plant – with the greatest potential savings to customers occurring in the "High" fuel price scenario.

56 Edison Electric Institute, PURPA: Making the Sequel Better than the Original, December 2006, Page 9.

57 Hydrodynamics Inc., 146 FERC ¶ 61,193 (Mar. 20, 2014) at P 34; 18 C.F.R. Sec. 292.304(d)(2).

This benchmark cost data also provides support for my conclusion that the current approved QF rates were consistent with the PURPA indifference standard, and that customers are not being burdened by rapid growth in the amount of QF power that is being purchased by the Utilities under the 2014 tariffs.

Q. HAVE THE UTILITIES REACHED THE SAME CONCLUSIONS?

A. Apparently not. Their witnesses apparently believe the current QF rates are too high, and they worry their ratepayers are being adversely affected by the rates currently being paid for QF power under existing PPAs.

Mr. Yates explained Duke's concern this way:

> As discussed in more detail by Witness Glen Snider, 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.
>
> DEC and DEP have long-term PPAs with Commission-set avoided cost rates ranging from $55 to $85 per MWh, while the Companies' current actual system incremental "avoided" costs are approximately $35 per MWh. As Mr. Snider details in his testimony, the Companies and our customers are paying approximately $80 million annually, or nearly $1 billion in total, more to solar developers than

> their actual avoided costs over the remaining life of the existing contracts.[58]

DNCP witness Petrie expressed a similar concern:

> The forward prices of fuel and power have dropped substantially over the last several years, causing the current payments to QFs under these contracts to be uneconomic. ...the current estimate of avoided costs, based on [recent] ICF and PJM data as discussed above, is substantially below the contractual rates paid to small QFs that signed agreements under the two prior avoided cost dockets.[59]

Q. HAVE THE UTILITIES COMPARED THEIR QF RATES TO THE FULL LIFE CYCLE COST OF THEIR OWN GENERATORS?

A. No. To my knowledge, they have not compared the cost of QF power to the cost of power produced by any of the new coal-fired or natural-gas fired generating plants they have added to their rate base in recent years. I believe an analysis of their recently added combined cycle plants would yield similar conclusions to the ones I have drawn from my benchmark cost comparisons.

58 Yates Direct, p. 7.

59 Direct Testimony of Bruce E. Petrie on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Petrie Direct"), p. 4.

Q. WHAT IS THE BASIS FOR THEIR CONCERN THAT RATEPAYERS MAY BE PAYING TOO MUCH FOR QF POWER?

A. Duke witness Snider explained in his testimony how he derived the $1 billion figure he used to quantify his understanding of the adverse impact of QF rates on Duke's ratepayers:

> ...changing economic and market conditions have caused a potential long-term overpayment of approximately $1.0 billion by customers compared to the Companies' current calculation of its avoided cost rates proposed in this proceeding.[60]

> DEC's and DEP's current estimated combined financial obligation for previously contracted solar QFs as of December 31, 2016, is approximately $2.9 billion, which ultimately will be paid for by our customers. If those contracts were valued at the most recently filed avoided cost rates, they would have a value of only $1.9 billion. This results in a gap of approximately $1.0 billion, representing the level of potential overpayment by customers as compared to the Companies' current proposed avoided cost rates filed in this proceeding.[61]

Before explaining my understanding of how he arrived at $1 billion, let me make clear what this number does <u>not</u> represent.

Mr. Snider is not comparing what Duke's customers pay for QF power to what those customers pay for power supplied by generating units in DEC or DEP's rate base. He is not comparing the cost of QF power to the projected life cycle

60 Snider Direct, p. 4.

61 Snider Direct, p. 13.

cost of power that would be generated by the nuclear units Duke still has under consideration. He is not comparing the QF rates to the estimated life cycle cost of power generated by one of the combined cycle or combustion turbine units which DEC and DEP has included in their Integrated Resource Plans, which are expected to be added to their rate base during the next 10 to 15 years.

Q. THEN WHAT IS THE BASIS FOR THESE STATEMENTS?

A. Duke witness Yates describes the $1 billion figure as being derived from:

> the Companies' current actual system incremental "avoided" costs [of] approximately $35 per MWh[.][62]

Duke witness Snider discussed the same $1 billion number, but he describes it a little differently, saying it represents

> ...the level of potential overpayment by customers as compared to the Companies' current proposed avoided cost rates filed in this proceeding.[63]

The latter explanation appears to be similar to one provided by DNCP witness Petrie, who described his analogous calculations as a comparison between the rates included in existing QF contracts and the ones being proposed in this

62 Yates Direct, p. 7.

63 Snider Direct, p. 13.

proceeding – which he describes as "the most recently filed avoided cost rates.".[64]

In discovery, Duke was asked to explain the $1 billion figure, as well as the underlying comparison between "$55 to $85 per MWh" for QF power and the estimated "current actual system incremental "avoided" costs" of approximately "$35 per Mwh".[65] With respect to the range of $55 to $85 per MWh, Duke explained this was based upon its review of existing contracts for:

> PURPA projects that are already connected or in construction, including both standard offer < or equal to 5 MW and negotiated agreements of greater than 5 MW. The $85/MWH and $55/MWH values reflect the high and low points of the calculated levelized rate for each contract in DEC's and DEP's database.[66]

Thus, the QF side of the comparison reflects levelized rates from the current standard offer tariff as well earlier vintage QF tariffs, which were based upon the higher fuel prices that prevailed at the time, and negotiated QF rates.

Importantly, the other side of the comparison – $35 per MWh – is a single point estimate or snapshot of Duke's current short run marginal costs:

> The single point estimate for current incremental hourly costs represents the weighted average hourly cost observed during 2015. 2015 was the last full year of hourly

64 Petrie Direct, p. 4.

65 Duke response to NCSEADR1-11.

66 Duke response to NCSEADR1-11.

> information available at the time the analysis was completed.

This is the same data I used earlier to compare Duke's marginal fuel costs during 2015 to its average fuel costs. However, rather than comparing two different numbers for the same year, Duke is comparing marginal fuel costs taken from a snapshot of a single year (2015) to levelized fixed QF prices that have been averaged across a large group of long term contracts (typically for 15 years), including ones that were signed when fuel prices were higher than they are currently, as well as ones that will remain in effect for years into the future.

Q. IS THIS A FAIR WAY OF COMPARING THE COST OF QF POWER TO POWER THAT DUKE GENERATES?

A. No. It greatly exaggerates the impact of the recent dip in fuel prices, and it creates an incorrect impression that the existing QF contracts are costlier than power produced by generating units Duke owns and operates. There are at least four fundamental problems with this comparison, which render it completely invalid.

First, no one knows what prices ratepayers will ultimately have to pay for the fuel Duke will burn in its fossil-fired generating units over the duration of these QF contracts. Duke is comparing a snapshot of fluctuating fuel prices taken at a time when fuel prices happened to be relatively low. When fuel prices move higher, the arithmetic will change – potentially rather drastically – and the comparison will look less favorable for Duke's fossil-fueled units. The gap between the QF fixed contract price and Duke's marginal cost of fuel could entirely disappear during the remaining years of these contracts, if fuel prices return to their historical trend line.

Second, the $1 billion estimate ignores differences in risk. A long-term contract with fixed prices is less risky for ratepayers, compared with the cost of burning fossil fuels, whose price can fluctuate widely over the course of just a few months or years. A fair comparison between a fixed price and a fluctuating one needs to acknowledge this difference – just as many people are willing to pay more for a fixed rate mortgage, and will only accept a floating rate mortgage if the interest rate is significantly lower.

Third, the $1 billion estimate is based upon a fundamental mismatch: the $35 per MWh figure only includes fuel costs. It does not include any of the fixed operating and maintenance expenses, property taxes, depreciation, income taxes, debt service or other fixed costs incurred by Duke, which ratepayers reimburse. In contrast, the QF contract sets forth an "All In" price which encompasses everything ratepayers pay for power obtained from the QF. Ratepayers are not required to pay anything else toward the QF's operating and maintenance costs, depreciation or other fixed costs.

Fourth, nearly all of the QF power is being generated during the daytime hours, when power is more valuable to ratepayers. In contrast, the $35 figure referenced by Duke witness Snider includes the lower fuel costs incurred late at night, when power is less valuable to ratepayers, and Duke's fuel costs are lower.

In effect, he is comparing the cost of a less valuable power, which is mostly produced during off-peak hours, with the cost of more valuable QF power, which is almost entirely produced during peak hours. The difference is reflected in the following table, using the same data discussed earlier in my testimony:

Duke Marginal Fuel Costs versus Average Fuel Costs[67]

	DEP	DEC
2015 Marginal Fuel Cost – On Peak	3.724 cents	3.723 cents
2015 Marginal Fuel Cost – Off Peak	3.264 cents	3.263 cents
2015 Marginal Fuel Cost – All Hours	3.494 cents	3.493 cents

67 Duke response to NCSEADR1-11, 2015 hourly marginal costs.xlsx; DEC and DEP Monthly Fuel Reports pursuant to NCUC Rule R8-52, February 3, 2016.

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING THE IMPACT OF CHANGES TO FUEL PRICES ON THESE SORTS OF COMPARISONS?

A. Yes. The Utilities have emphasized the impact of falling fuel prices in drawing comparisons between QF contracts that were signed in earlier years with costs that are estimated currently, based on the lower fuel prices that are currently prevailing.

> In general, 10-year (2017 to 2026) levelized natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period as compared to those used in calculating the Companies' avoided cost of energy in the 2014 biennial Sub 140 proceeding. Compared to the 2012 Sub 136 avoided energy costs, fuel costs have fallen even further with natural gas declining approximately 48% and coal, 33%. [68]

A valid comparison of QF generation to fossil fueled generation will recognize and take into account this downward shift in fuel prices (as I did when developing my benchmark cost comparisons). And, it is important to understand that any such comparison will inevitably look less favorable when looking at existing QF contracts that were based on the higher fuel prices that prevailed when the current and earlier vintages of QF rates were approved by the Commission.

68 Snider Direct, p. 16.

However, this sort of comparison should be kept in the proper perspective. For instance, ratepayers are paying the full life cycle cost of the Cliffside 6 coal fired generating unit, which was planned and constructed based upon fuel forecasts that have subsequently proven to be inaccurate. With changes in the relative price of coal and natural gas, the technology used at the Cliffside plant no longer appears to be as attractive as it must have seemed when this technology was chosen in lieu of natural gas-fired combined cycle units.

My point in using this example is not to criticize Duke for committing to a coal fired unit with a 40-year life right before natural gas prices plunged. I am simply trying to point out that all sources of electricity involve economic uncertainties and risks that may seem less attractive in hindsight than they did at the time the decisions were made. It is fundamentally unfair to criticize the solar industry for building facilities that made economic sense based on projections of high gas prices, when Duke itself made a similar decision to build a high technology coal plant based on projections of high gas prices.

Just because some of the earliest solar projects now appear to be costlier than they did before gas prices dropped does not mean those contracts are unfair or burdensome to ratepayers. Nor does it indicate the decision to purchase QF power was unreasonable at the time the contract was signed. Similarly, it would not be reasonable to conclude from comparisons based upon older vintage contracts that QF power is an inherently costly or risky way of obtaining power, or that fundamental changes need to be made in the way the Commission implements PURPA.

Section 4: PURPA and the Indifference Standard

Q. BEFORE EXPLAINING YOUR BENCHMARK AVOIDED COST DATA, CAN YOU PLEASE EXPLAIN YOUR UNDERSTANDING OF THE FEDERAL STANDARDS WHICH YOU CONSIDERED IN DEVELOPING THIS DATA?

A. Yes. PURPA requires the FERC to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity."[69]

A key theme running through the FERC's rules implementing PURPA and related caselaw on this guidance is that QF rates should be based upon incremental or avoided costs, which should leave ratepayers indifferent as to whether their power is generated by the incumbent utility, or purchased from a QF.

69 16 U.S.C. § 824a-3.

Q. CAN YOU EXPLAIN THE "INDIFFERENCE" STANDARD AND THE "AVOIDED COST" CONCEPT?

A. Yes. As the FERC has stated on several occasions, the intention of Congress in enacting PURPA "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA.[70] As explained more recently by the North Carolina Utilities Commission, "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[71] Although PURPA is designed to encourage QF development, it does not accomplish this by subsidizing QFs, or by requiring customers to pay more for their power. To the contrary, if PURPA is correctly implemented, ratepayers are "held harmless," leaving them indifferent to whether they receive power from a QF or from new generating units added to the utility's rate base.

The FERC rules implementing PURPA generally require electric utilities to purchase any energy and capacity which is made available to the utility from a QF.[72] Rates for purchases from Qualifying Facilities built after 1978 must be based upon the electric utility's "avoided costs."[73] Although the term

70 Southern Cal. Edison, San Diego Gas & Elec., 71 FERC ¶ 61,269 at p. 62,080 (1995).

71 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 21.

72 18 C.F.R. § 292.303(a).

73 18 C.F.R. § 292.101(b).

"avoided cost" is not used in the text of PURPA, it is consistent with the statutory language referencing the "incremental cost of alternative electric energy," which is defined in PURPA as: "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." More specifically, FERC defines avoided costs as:

> [T]he incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[74]

Among other things, the FERC rules require state commissions, to the extent practicable, to consider these factors when determining avoided costs:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> > (i) The ability of the utility to dispatch the qualifying facility;
> >
> > (ii) The expected or demonstrated reliability of the qualifying facility;
> >
> > (iii) The terms of any contract or other legally enforceable obligation, including the duration of the

74 18 CFR § 292.101(b)(6).

obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy

> itself or purchased an equivalent amount of electric energy or capacity.[75]

Q. CAN YOU EXPLAIN WHAT INFORMATION IS REQUIRED BY SECTION 292.302(b) OF TITLE 18 OF THE CODE OF FEDERAL REGULATIONS?

A. Yes. Under part C of Section 210 of PURPA, electric utilities like Duke and DNCP are required not less often than every two years to provide to their state regulatory commission the following information, and to make it available for public inspection:

> (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

75 18 CFR § 292.304(e).

> individual generating units and of individual planned firm purchases.

Q. HOW CAN "AVOIDED COSTS" BE ESTIMATED?

A. There are just three major methods that have historically been used to develop avoided cost estimates. These are (a) the Proxy Unit method (also sometimes referred to as the Proxy Resource or Committed Unit method), (b) the Differential Revenue Requirement ("DRR") method, and (c) the Peaker method.[76]

All three of these methods are intended to measure the same thing (long run incremental costs), so all three methods can (and should) yield approximately the same total cost per kWh (assuming each one is properly performed using similar inputs and assumptions).

Q. CAN YOU BRIEFLY EXPLAIN THE PROXY UNIT METHOD?

A. Yes. The Proxy Unit (or Proxy Resource) method is described in the PURPA Title II Compliance Manual as follows:

> This method bases the avoided cost on the cost of the host utility's next planned addition, typically a combined cycle/gas turbine (CCGT) generating unit. This approach essentially assumes that the QF substitutes for a planned utility generating unit, or what is assumed to be the next

76 PURPA: Making the Sequel Better than the Original, p. 9. See also PURPA Title II Compliance Manual, p. 35; Reviving PURPA's Purpose, Carolyn Elefant, p. 13.

> generating unit. The proxy unit's estimated fixed cost (annualized over the expected life of the unit) determines the avoided capacity cost and the estimated variable cost sets the avoided energy cost. The type and size of the unit or units is determined in an Integrated Resource Process (IRP) or from the utility's planning process, where the planning process, for regulated utilities, follows a state commission-approved procedure. Because this is a relatively simple method to use, the proxy method is very common, although the results largely depend on the type of unit or units chosen as the proxy.[77]

This methodology has many advantages, including the fact that it is relatively straightforward and easily understood. Its flexibility is also an advantage: It can be implemented using data for a generating unit that is currently under construction, or has recently been constructed by the utility, a unit that has been identified for future construction in the utility's Integrated Resource Plan, a hypothetical or surrogate unit, or some combination or variant of these data sources.

I have used the Proxy Unit method to develop my benchmark estimates of avoided costs, which I have used to evaluate the current and proposed QF rates, and for other illustrative purposes.

77 PURPA Title II Compliance Manual, p. 35.

Q. ARE YOU ASKING THE COMMISSION TO ADOPT THE PROXY UNIT METHOD IN LIEU OF THE PEAKER METHOD?

A. No, not at all. The Commission has a long history of using the Peaker Method to develop QF rates, and I am not in any way suggesting it should abandon that long-standing practice. All three of the standard methods for estimating avoided costs are intended to measure the same thing, and the choice of a specific method in a specific context is largely a matter of administrative or calculational convenience.

In this instance, it was convenient for me to use the Proxy Unit method to illustrate and clarify various of points in my testimony. The Proxy Unit method was ideal for this purpose because: First, it is a relatively straightforward, simple method which is relatively easy to explain, implement and understand. Second, it can be developed using publicly available information, thereby improving transparency and reliability. Third, it is well suited for consideration of the information that must be provided by utilities pursuant to 18 C.F.R. Section 292.302(b) as I mentioned earlier in my testimony.[78] This is significant, since the FERC rules specifically require state regulators to consider this information in setting avoided-cost based rates, to

78 All of the information submitted by utilities pursuant to this regulation tends to be useful, including the cost of planned capacity additions and firm purchases on the basis of dollars per kilowatt, and the associated costs of each unit, expressed in cents per kilowatt hour.

the extent practicable.[79] Moreover, this avoided cost data is available for many different utilities, potentially facilitating comparisons with data submitted by other utilities. Fourth, the proxy unit method offers great flexibility, which made it easier to develop multiple different calculations using a wide variety of different assumptions (e.g. fuel choices and cost scenarios).

None of the conclusions I have reached in my testimony are contingent on the use of the Proxy Unit method, nor am I suggesting the Commission, should use the Proxy Unit method to determine the QF rates that are established in this proceeding.

Q. CAN YOU BRIEFLY EXPLAIN THE DIFFERENTIAL REVENUE REQUIREMENT METHOD?

A. Yes. The DRR method is described in the PURPA Title II Compliance Manual as follows:

79 18 CFR § 292.304(e).

> Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF.[80]

The DRR method, as typically discussed, is a fairly complex approach, requiring the use of two different computer models.

> A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QFs are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes)[81]

Q. CAN YOU BRIEFLY EXPLAIN THE PEAKER METHOD?

A. This is the method which Duke has historically used in both South and North Carolina. The Peaker Method is described in the PURPA Title II Compliance Manual as follows:

> Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. If the utility requires capacity, this method sets the avoided capacity at the lowest-cost capacity option available to the utility, for example, a combustion turbine (CT). Avoided energy cost may be based on the utility's system-wide avoided energy cost, not the peaking unit's energy cost. This requires production cost modeling to determine the system-wide avoided

80 PURPA Title II Compliance Manual, p. 35.

81 PURPA: Making the Sequel Better than the Original, December 2006, p. 11.

> energy cost, which increases the complexity of this method over the "proxy" unit approach.[82]

The Peaker method has at least one significant advantage: it develops energy cost estimates on an hour-by-hour, year-by-year basis. However, some of this advantage can be lost when the calculations are averaged and levelized across broad, potentially arbitrary "Peak" and "Non-Peak" categories and seasons (groups of months). The Peaker Method also has at least one significant disadvantage: it is not especially well-suited to fully utilize the information provided pursuant to 18 CFR Section 292.302(b), particularly with regard to the incremental cost of nuclear and other baseload generating units, since this data isn't used in the Peaker Method.

Q. DO ALL THREE METHODS ESTIMATE THE INCREMENTAL COST OF BUILDING AND OPERATING NEW GENERATING FACILITIES OVER THEIR ECONOMIC LIFE CYCLE?

A. They can, and in my opinion they should. Incremental life cycle cost is an appropriate benchmark, which can be estimated using any of these methods, if they are correctly implemented with appropriate assumptions and inputs.

It is easiest to see this with the Proxy Unit method, which specifically focuses on the life cycle cost of owning and operating a specific unit. Like any

82 PURPA Title II Compliance Manual, p. 35.

method, however, the costs that are calculated will vary – particularly on a per kWh basis – depending on the assumptions and inputs which are selected, and how they are used. For instance, if avoided costs are being calculated for use in paying QFs for power that will be generated during many hours of the year, the primary focus should be on a proxy unit that is cost-effective in serving long duration loads, like a combined cycle or nuclear unit. If the analysis were limited to a peaking unit instead, the resulting cost per kWh could be higher than the full life cycle cost of owning and operating a baseload plant, because a combustion turbine has very high fuel costs, which outweigh its low construction costs if power is going to be provided during many hours of a typical day.

The Peaker Method will also achieve this benchmark when appropriately implemented, although it is not intuitively obvious how it can accomplish this, since it focuses on the capital cost of a peaker (combustion turbine or CT) rather than a base load plant. As I explained earlier in my testimony, the Peaker Method, assumes combustion turbines with poor heat rates will be operated at the top of the dispatch stack during enough hours of the year to ensure that the difference in fuel costs (e.g. between a new peaking unit and a new nuclear generating unit) will compensate for the additional capital costs of the baseload unit.

Stated another way, the Peaker Method does not provide recovery of the high fixed costs of a baseload plant like a combined cycle unit or nuclear plant in the avoided capacity cost results. Instead, the capacity costs are limited to those of a CT, while the remainder of the fixed costs of owning and operating a baseload plant are supposed to show up in the energy costs. The avoided energy costs are based upon the "top of the stack" (typically, the least fuel-efficient generating unit that is running during any given hour), which are expected to exceed the cost of fuel for baseload units by an amount that should be large enough to recover the portion of the baseload plant investment that exceeds the investment in a peaking unit.

Q. CAN YOU BRIEFLY HIGHLIGHT SOME PRACTICAL ISSUES WITH RESPECT TO PRODUCTION COST MODELS, LIKE PROSYM?

A. Yes. The Peaker method takes advantage of computerized production cost modeling to estimate avoided energy costs on an hour-by-hour, year-by-year basis. The great advantage of these models is that they produce cost estimates in extreme granular detail (literally 8,760 different cost numbers are generated for each year), and they can easily accomplish this level of granular detail for many different scenarios – simply by adjusting the inputs used in running the model for each scenario.

For instance, a production cost model can easily develop precise estimates of how costs will be affected during various time periods and seasons, depending on what happens to fuel prices in future years. Unfortunately, neither Duke nor DNCP took full advantage of the ability of programs like Prosym to produce detailed, hourly output that make it feasible to understand and compare the impact of different scenarios. For instance, they did not provide hourly cost estimates showing the impact of different scenarios that vary based upon the rate of growth in solar energy being added to the grid in future years.

Furthermore, the Utilities did not use the granular output from their production cost models to support their proposed peak and off peak rate periods, or to support their position concerning the impact of solar growth on their operations. Instead, the simply summarized or aggregated this data across the existing peak and off peak time periods. This reduces or eliminates some of the potential benefits of using Prosym to develop energy costs on a detailed, hour-by-hour, year-by-year basis. Similarly, the Utilities did not take full advantage of their production cost model's inherent "What if" capabilities to provide the Commission and other interested parties with energy cost estimates under multiple different scenarios (e.g. higher or lower fuel prices in future years).

This highlights one of the most significant disadvantages of using a production cost model: they are data-intensive and costly to license. Furthermore, extensive training is required before these models can be operated reliably. Because of these licensing and training barriers, the model effectively becomes a "black box" for most other parties, which cannot easily be penetrated by the Commission, the Public Staff, or other parties. Due to licensing costs and other barriers, it is difficult or impractical for most other parties to probe the underlying inputs and assumptions that drive the avoided energy cost estimates produced by a model like Prosym. This is a significant consideration, since the inputs largely control the outputs of these types of computer models.

Q. PLEASE BRIEFLY EXPLAIN YOUR AVOIDED COSTS ESTIMATES.

A. I started by estimating the cost of constructing and owning a hypothetical nuclear plant, a hypothetical combined cycle plant, and a hypothetical combustion turbine. I then combined this data with estimates of the cost of fueling and operating these plants, and converted this data into per-kWh cost estimates.

Q. CAN YOU BRIEFLY EXPLAIN HOW YOU ESTIMATED THE COST OF CONSTRUCTION FOR A NEW NUCLEAR GENERATING UNIT?

A. In my avoided cost analysis I assumed an installed cost of $5,350 per kW for a newly constructed nuclear unit. I developed this number by looking at publicly available information concerning construction costs, including the cost of the V.C. Summer nuclear plants which SCE&G currently has under construction, since I recently had occasion to study those costs.[83] I started with the $7.6 billion cost estimate for the V.C. Summer units, which was provided in SCE&G's June 2016 PURPA filing. However, I recognized that the actual cost of construction will not be known until the units are completed. (The analogous estimate in the 2014 PURPA filing was $5.76 billion.)[84]

Also, I recognize there is a learning curve involved with nuclear units, and thus future units might be less costly than the ones that are currently under development. Hence, I also considered the most recent available cost estimate published by the Energy Information Administration ("EIA") for new nuclear

83 SCE&G's June 30, 2016 avoided cost filing in compliance with Subpart C, Section 210 of PURPA indicates the first planned unit is V.C. Summer #2, which is projected to add 625 MW of capacity in 2020, 22 MW of capacity in 2021, and 23 MW in 2022. V.C. Summer #3 is expected to add 648 MW of additional nuclear capacity in 2021 and another 22 MW of capacity in 2022, for a grand total of 1,340 MW. SCE&G's 2016 avoided cost filing is available at: https://dms.psc.sc.gov/Attachments/Matter/47629bd9-e607-47ba-a766-fd93412ce610 (last accessed March 27, 2017).

84 SCE&G's 2014 avoided cost filing is available at: https://dms.psc.sc.gov/attachments/matter/5180191F-155D-141F-239A12DA68A40511 (last accessed March 27, 2017).

construction, which I adjusted to 2017 dollars using an annual inflation rate of 2.0% and to reflect local cost conditions using their state-specific cost adjustment factor:

Nuclear	Cost per KW in 2017 Dollars
Proxy Unit	**$ 5,350**
EIA – Advanced Nuclear [85]	$ 5,712
SCE&G – Summer June 2016 Estimate	$ 5,307

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBINED CYCLE UNIT?

A. I started with an installed cost per KW in 2017 dollars of $1,050. This is consistent with these publicly available data sources:

Combined Cycle	Cost per KW in 2017 Dollars
Proxy Unit	**$ 1,050**
EIA – Advanced CC[86]	$ 1,023
DEC – Dan River CC[87]	$ 1,077

85 Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 ("2016 EIA Report"), p. 7. My calculations apply EIA's location adjustment factor for North Carolina (Page A-20) and adjust for inflation at 2% per year.

86 2016 EIA Report, p. A-14.

87 DEC completed its Dan River combined cycle plant in 2012. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $912, which is equivalent to approximately $1,077 in 2017 dollars.

DEC – Buck CC[88]	$ 1,060
Brattle – Dominion [89]	$ 1,041

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBUSTION TURBINE?

A. I used an installed cost of $650 per KW in 2017. This is primarily based upon the most recent cost information published by the EIA, but I also considered other publicly available data sources:

Combustion Turbine	Cost per KW in 2017 Dollars
Proxy Unit	**$ 650**
EIA – Advanced CT [90]	$ 639
Brattle – Dominion [91]	$ 885
Pasteris SOM – EMACC [92]	$ 763

88 DEC completed its Buck combined cycle plant in 2011. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $941 per KW, which is equivalent to approximately $1,060 per KW in 2017 dollars.

89 The Brattle Group and Sargent & Lundy, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, May 2014 ("Brattle Report"), p. 43, available at: http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf?1400252453 (last accessed March 27, 2017).

90 2016 EIA Report, p. A-18.

91 Brattle's estimate of the overnight cost of constructing an Advanced Combustion Turbine in Dominion's service area was $931 per KW in 2018/19. Brattle Report, p. 41.

92 Pasteris Energy, Inc., Brattle CONE Combustion Turbine Revenue Requirements Review, July 25, 2014, p. 12, available at: http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20140725/20140725-brattle-vs-ma-som-cone-ct-revenue-requirements-comparison-final-report.ashx (last accessed March 27, 2017).

SCE&G – 2023 CT [93]	$ 734

Q. HOW DID YOU TRANSLATE THE INSTALLED COST INTO ANNUAL EQUIVALENTS?

A. First, I added an allowance for the cost of construction financing. I then developed an allowance for depreciation based on an economic life of 30 years for the combined cycle and combustion turbine units, and 70 years for the nuclear unit. I developed an estimate of income taxes using a composite state and federal tax rate of 34.93%, and I applied a weighted cost of capital of 7.36% (a pre-tax cost of capital of 10.17%), consistent with the following calculations:

Capital Source	Ratio	Cost Rate	Weighted Cost	Tax Factor	Pre-Tax Weighted Cost
Equity	50.00%	9.50%	4.75%	1.5367	7.30%
Debt	50.00%	4.75%	2.38%	1.0000	2.38%
Total	100.00%		7.36%		9.67%

The costs were initially developed for each individual year, then levelized across the entire economic life of the plant. The latter step is similar to the way most home mortgages are structured to provide uniform, level payments, even though the cost of the mortgage (the interest) varies from year to year.

93 SCE&G 2014 avoided cost filing.

The end result was a uniform levelized capital cost of $490.75 per kW per year for the nuclear plant, $113.04 per kW per year for the combined cycle plant and $69.97 per kW per year for the combustion turbine.

Q. DID YOU CONSIDER ANY OTHER FIXED ANNUAL COSTS?

A. Yes. Before converting these levelized amounts into per-kWh costs, it was necessary to add an allowance for fixed operating and maintenance and corporate overhead costs. I assumed annual fixed operating and maintenance expenses would be $95.00 per kW for the nuclear plant, $10.00 per kW for the combined cycle Plant and $7.00 per kW for the advanced combustion turbine (in 2016 dollars). The assumptions are consistent with estimates developed by the Energy Information Administration and data from various utilities, which I have reviewed in the course of my consulting work. Applying an annual inflation factor of 2% and levelizing each figure results in an annual cost per kW in 2017 of $136.00, $12.64 and $8.85, respectively.

I also applied a 95% availability factor, to compensate for forced outages and times when the unit is unavailable for energy production due to scheduled maintenance (and refueling in the case of a nuclear unit). An allowance for corporate overhead costs was also needed; I provided a 5% allowance for this category of costs. All of these costs were developed on a year-by-year basis, then uniformly spread across the economic life of the plant. The resulting levelized costs totaled $692.72 per kW for the nuclear plant, $138.90 per kW for the combined cycle plant and $87.12 per kW for the combustion turbine.

Q. HOW DID YOU ESTIMATE AVOIDED ENERGY COSTS?

A. I developed separate avoided energy cost estimates for the hypothetical nuclear plant, the hypothetical combined cycle plant and the hypothetical combustion turbine. When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind, and these were a major element of this part of the cost estimation process. However, my energy-related cost estimates also include certain fixed capital-related costs, as I mentioned earlier in my testimony. To arrive at an accurate distinction between costs that are attributable to the need for capacity during peak hours and costs that are energy related, it was necessary to recognize that some of the costs of building and owning the nuclear and combined cycle units were energy-related.

Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion of all three proxy units was limited to the annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant are were treated as "energy-related." This disaggregation is widely accepted – in fact, it is fundamental to the theoretical underpinnings of the Peaker Method.

The extra step involved in disaggregating fixed costs is particularly useful when examining the economics of a nuclear unit. In fact, the great majority of the capital investment in a nuclear plant is not attributable to the goal of meeting peak capacity (although a nuclear plant also provides capacity for achieving that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs.

The uranium used to fuel a nuclear plant costs tends to be less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using this technology. No one would invest in a nuclear unit just to provide capacity during peak hours. The added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

After drawing this distinction, the levelized fixed annual cost estimates in 2017 dollars are summarized in the following table:

Cost per kW/Year	Nuclear	Combined Cycle	CT
Capacity Related	$ 87.12	$ 87.12	$ 87.12
Energy Related	605.61	51.78	0.00
Total	$ 692.72	$ 138.90	$ 87.12

Q. HOW DID YOU HANDLE FUEL AND OTHER VARIABLE COSTS?

A. Variable costs can be difficult to deal with, because they are highly dependent on future fuel prices, which are not knowable with any degree of precision.

For example, natural gas prices have exhibited wide fluctuations over both short and medium time frames, although they have exhibited a tendency to trend higher and higher over the long term. The problem with price instability was vividly illustrated during 2016, when natural gas prices plunged by more than 20% during a few months early in the year, and then shot upward by nearly 40% over an even shorter time period later in the year.

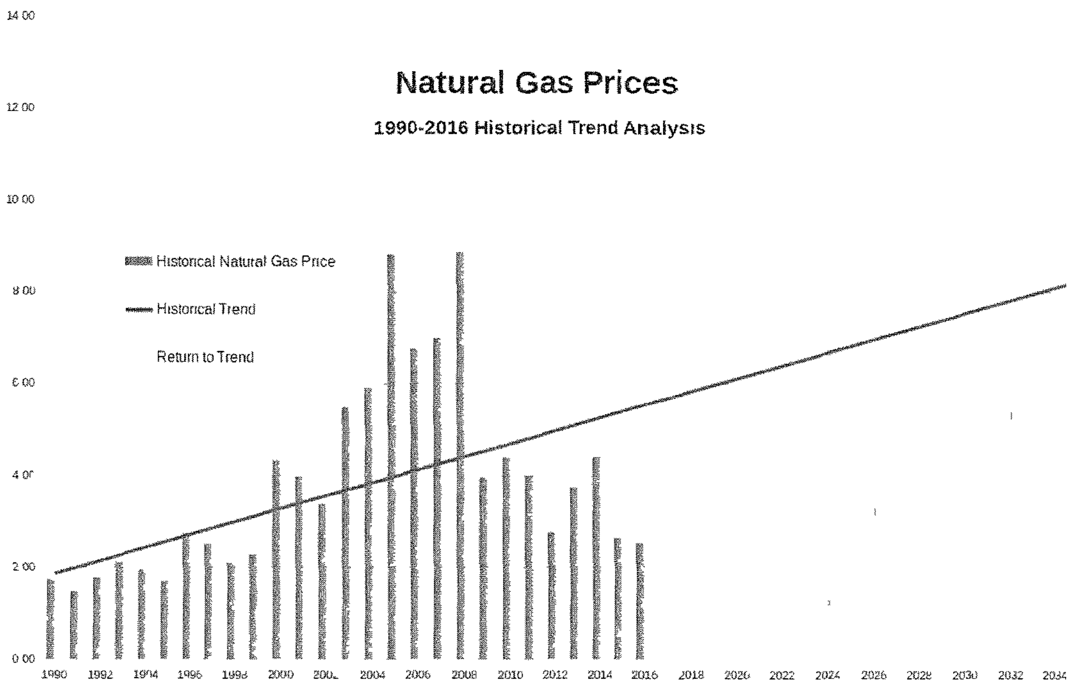
Recently, gas prices returned to very low levels – in fact, the Wall Street Journal had a headline on the front page of its March 15, 2017 edition with the headline "Natural-Gas Glut Deepens." At current prices, gas is so inexpensive it might appear that other options – like coal and nuclear – are undesirable. However, such a conclusion would be premature, since generating plants are 30+ year investments, and the relative merits of each technology need to be evaluated from a long-term perspective.

In fact, the instability of natural gas prices, and difficulties associated with predicting these prices is one of the principal disadvantages, or risks, associated with using this fuel source. These risks are important to keep in mind when evaluating the merits of long-term investments in gas-fueled generation relative to other options. Coal has some of the same risk characteristics as gas, but to a lesser degree, since coal prices tend to be more stable and because coal can be sometimes be purchased from coal mines pursuant to multi-year contracts at fixed prices.

The key point is that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Q. CAN YOU ELABORATE ON THESE PROBLEMS?

A. Yes. The following graph shows the long term upward trend in natural gas prices from 1990 through 2016. The light blue bars show average gas prices experienced during each of these years, using data obtained from Reuters (1990-96) and the EIA (1997-2015). The dark blue line shows the linear trend reflected in that historical data, extended into the future.



Finally, the pale yellow bars on the right side of the graph shows what future would look like, if gas prices were to smoothly return to the historical trend line and follow the slope of the historical trend line thereafter. Given the wide fluctuations observed in the historical data (light blue bars), it is apparent that fuel prices cannot be accurately predicted years in advance of when it is purchased. This greatly complicates any attempt to analyze the cost of producing electricity using different technologies or fuels.

This problem is particularly acute when comparing the cost of generating sources that burn fossil fuels with those that do not – like nuclear power, hydro, and solar. The extent to which one concludes the latter technologies are higher or lower cost options for ratepayers will be almost entirely dependent upon whatever assumptions or projections are made concerning future fuel prices. A similar problem arises when trying to analyze the impact on ratepayers of obtaining power at fixed long-term prices from a QF compared to having the utility build new generating plants that will burn fossil fuel purchased at prices that are not known in advance, and cannot be predicted with any degree of certainty.

Q. CAN YOU GIVE A REAL-WORLD EXAMPLE OF HOW UNCERTAINTIES CONCERNING FUTURE NATURAL GAS PRICES CAN BE DEALT WITH IN THIS TYPE OF ANALYSIS?

A. Yes. This example is drawn from the recent experience in South Carolina where SCE&G evaluated the economic viability of its V.C. Summer nuclear construction project. The utility considered several different scenarios concerning potential future gas prices – all of which were higher than the unusually low prices that have recently been observed.[94] SCE&G started with

> "two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices

94 South Carolina Electric & Gas, Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, May 26, 2015, available at: https://dms.psc.sc.gov/Attachments/Matter/4c84883e-157b-4ad4-856a-c49a3c0b1b25 (last accessed March 27, 2017).

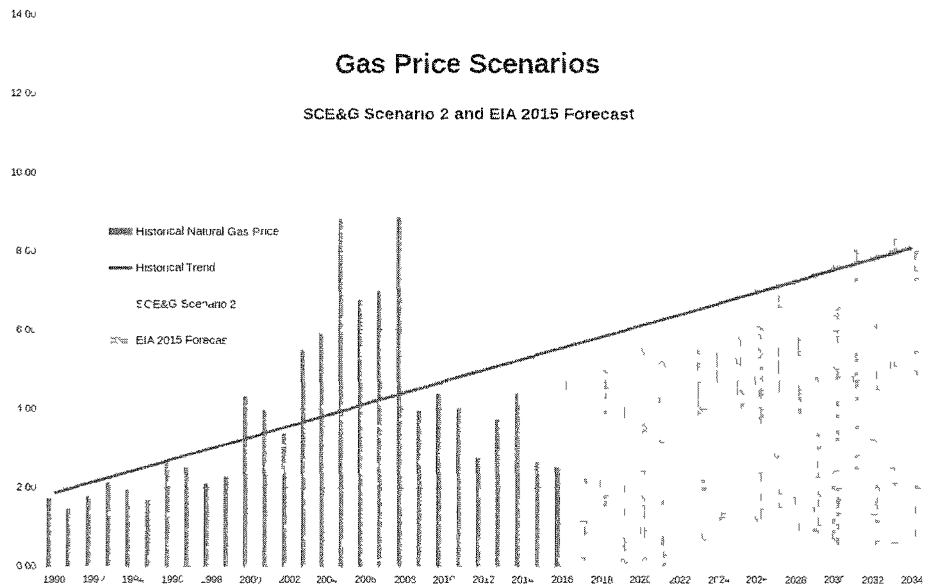
> reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor … to forecast prices beyond three years in the future."[95]

The latter forecast, which it described as its "base line forecast" of natural gas prices, was the lowest of three forecasts it developed and used for its evaluation. SCE&G also evaluated the impact of natural gas prices being 50% higher (Scenario 2) or 100% higher (Scenario 3) than this baseline.[96]

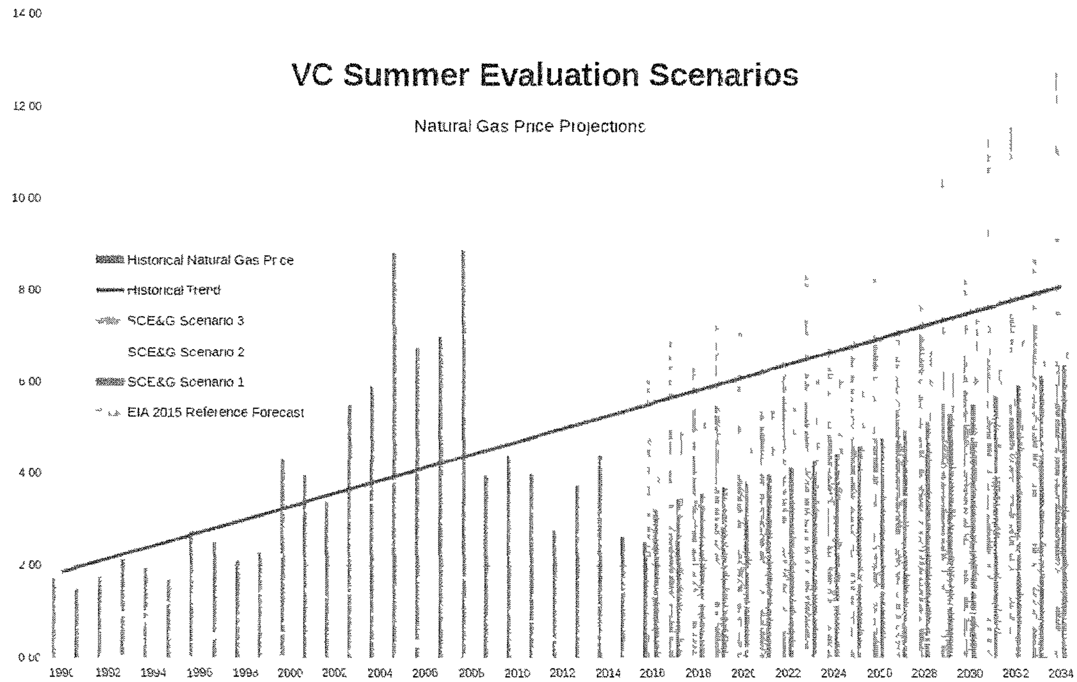
Scenario 2 and the 2015 EIA baseline forecast were both similar to the historical trend as well as each other, as shown in the following graph:

95 Id., p. 3.

96 Id., p. 3.



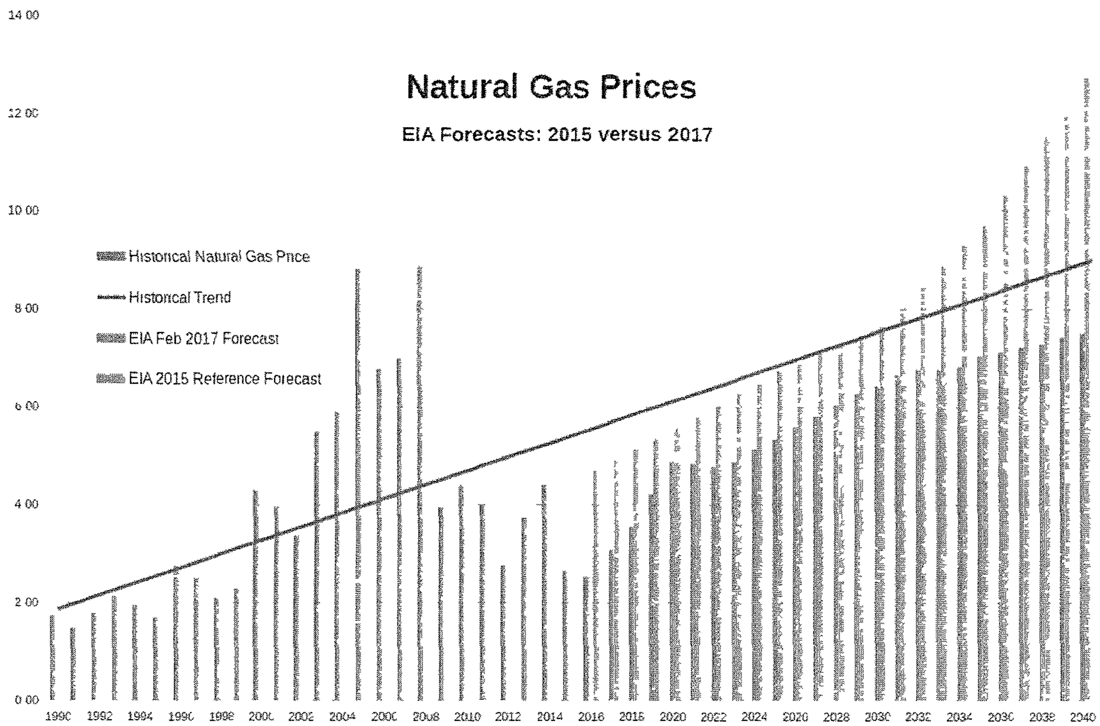
Recognizing that "all forecasts of future gas prices are subject to error" SCE&G looked at multiple scenarios, with their Baseline Scenario 1 forming the bottom of the range, Scenario 2 and the EIA's 2015 forecast falling in the middle, and Scenario 3 moving well above the others. Strictly speaking, Scenario 3 was not the highest pricing scenario SCE&G considered, since it also considered the impact of adding an estimate of the cost of carbon to natural gas prices. The three SCE&G scenarios are shown in the following graph, which also includes historical data through 2016, and the historical trend line.



When reviewing this graph, it is important to keep in mind that the V.C. Summer evaluation was completed in June 2015, before most of the 2015 prices, or any of the 2016 prices were known.

Q. HAVE FUEL PRICE FORECASTS DECLINED IN REACTION TO LOWER PRICES?

A. Yes. Many forecasters have reduced their expectations for long term future prices, as well as near-term prices. For example, the following graph compares the EIA's 2015 forecast with its 2017 forecast, which was published in March 2017:

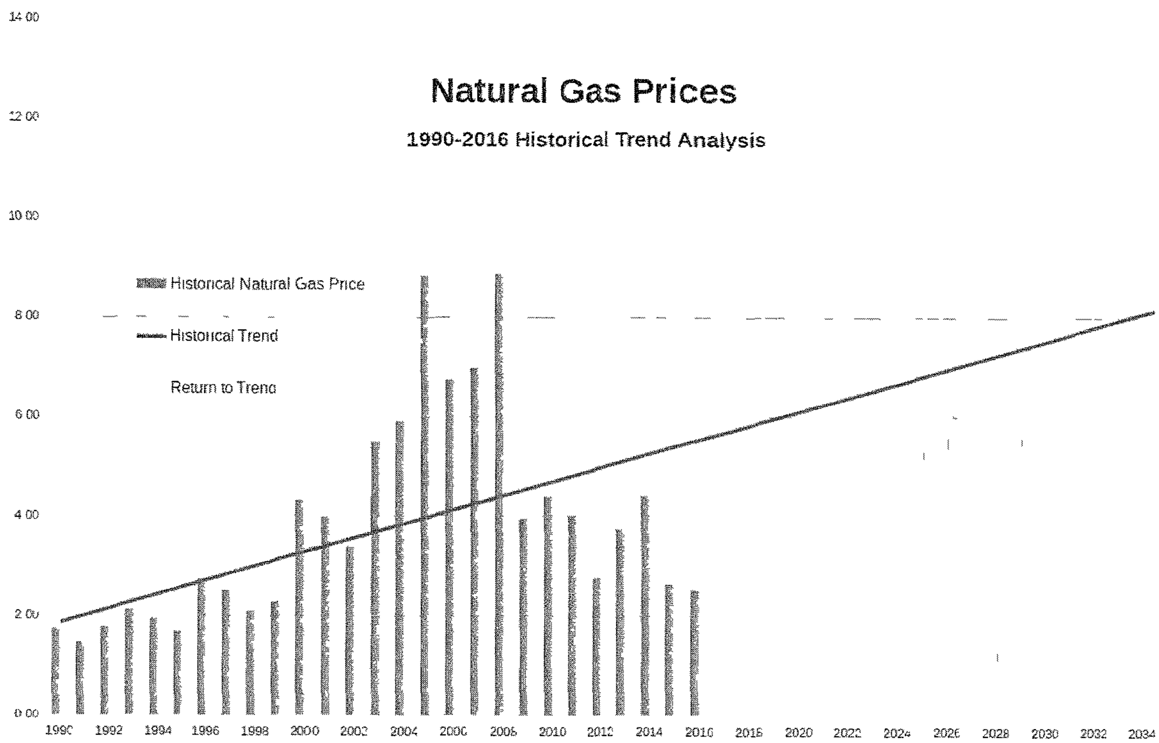


The earlier forecast (light green) is consistently higher than the most recent forecast, because that forecast takes into account the recent experience.

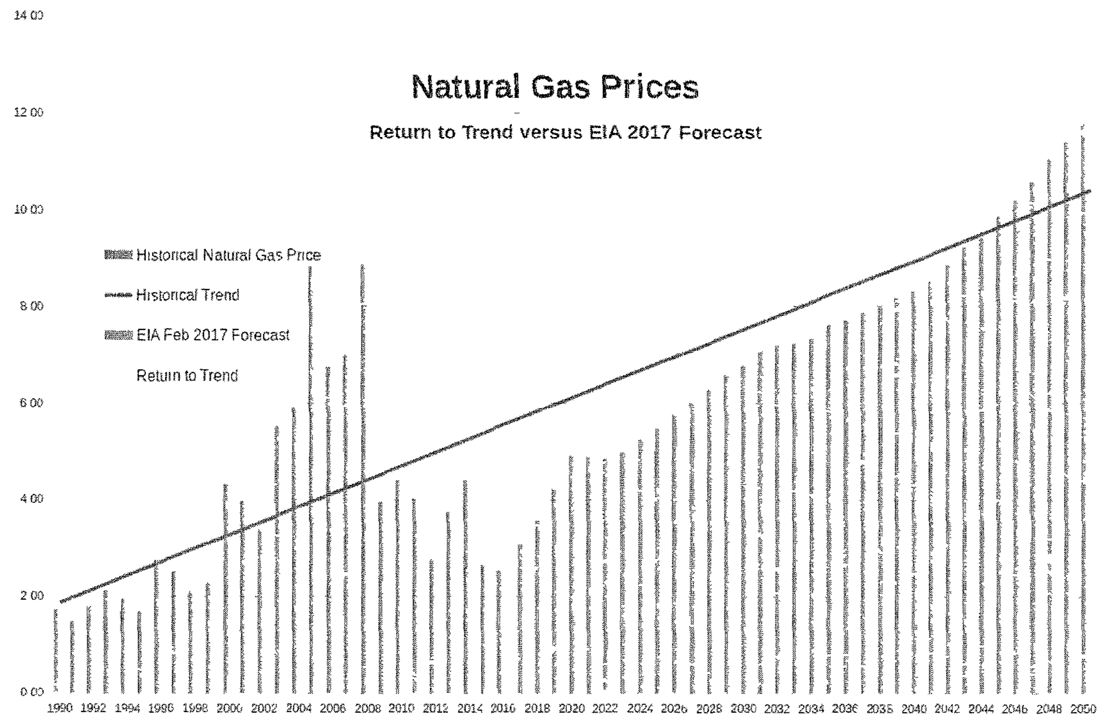
Q. WHAT FUEL PRICES DID YOU USE TO DEVELOP YOUR LONG RUN AVOIDED COST ESTIMATES?

A. I evaluated multiple scenarios, similar to the way SCE&G evaluated its V.C. Summer units. One scenario assumed natural gas prices gradually return to the historical trend line, then follow the trend line, as shown in this graph:

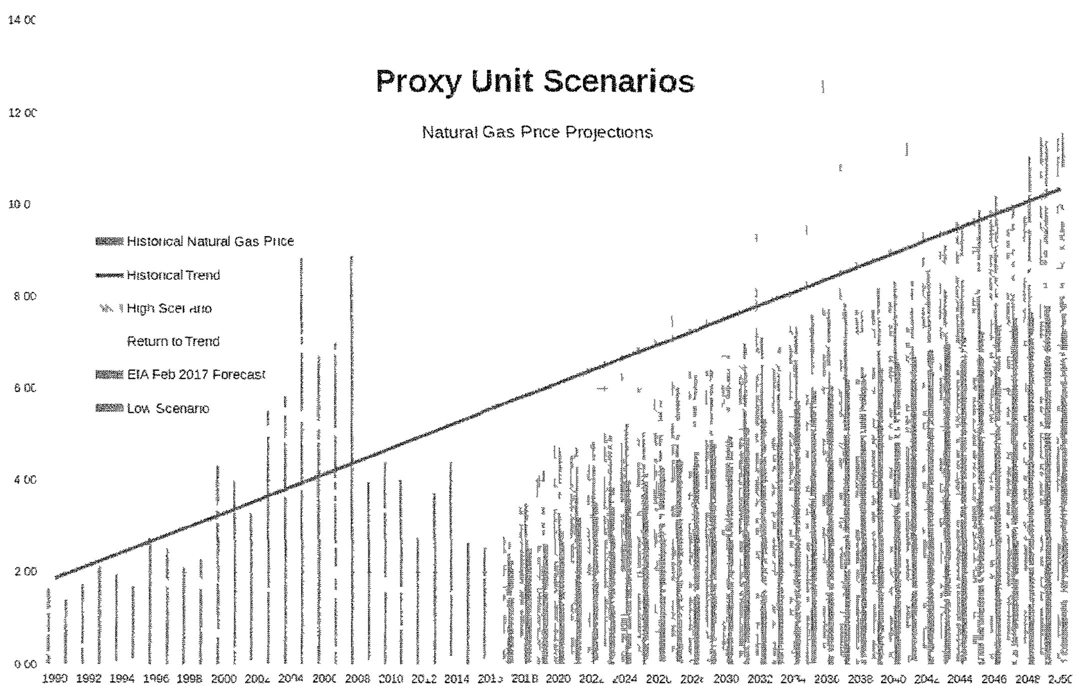
Another scenario was based upon the EIA's recently published 2017 baseline fuel price forecast, shown in the previous graph. The EIA's 2017 forecast is



similar to the trend-based scenario, but the EIA prices sometimes move a little above and sometimes a little below the smoother "Return to Trend" assumptions. This is shown in the following graph:



I also bracketed these scenarios with a lower price scenario and a higher one. The lowest scenario was derived from SCE&G's Scenario 1 while the highest price scenario was derived from SCE&G's Scenario 3. However, I lowered all of the prices in the initial years, to reflect the 2015 and 2016 historical data, which was not available when SCE&G prepared its V.C. Summer evaluation. All four scenarios are shown in the following graph:



Q. DID YOU MAKE ANY OTHER ASSUMPTIONS RELATED TO FUEL COSTS?

A Yes. First, I assumed fuel prices would eventually grow at the overall inflation rate (2%) except in the "High" scenario, where I assumed gas prices would increase 0.5% per year faster than the overall rate of inflation. Second, I assumed a heat rate of 6,500 BTU/kWh for the combined cycle unit and 9,750 BTU/kWh for the combustion turbine unit. Third, I provided an allowance for non-fuel-related variable Operating and Maintenance costs of \$2.50 per MWh for the combined cycle unit, \$11.00 per MWh for the combustion turbine and \$2.35 per MWh for the nuclear unit in 2016 dollars, before applying a 2% per annum inflation factor. Fourth, I assumed nuclear fuel costs of 1.00 cents per kWh in 2016 Dollars, before applying a 2% per annum inflation factor. This is consistent with, or slightly lower than, the estimates reported by SCE&G in their June 2016 FERC avoided cost report under Subpart C, Section 210 of PURPA.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING RECOVERY OF FIXED COSTS OVER DIFFERENT TIME PERIODS AND SEASONS?

A. Capacity-related fixed costs are appropriately attributed to peak hours and seasons. To some extent, the same logic holds for energy-related fixed costs, which should also be recovered disproportionately during daytime hours, when energy usage is relatively high.

In the Peaker Method, this can be accomplished by disaggregating the production modeling output during different time periods and seasons, and by focusing on marginal energy costs, rather than average energy costs. Since marginal costs tend to be high during hours when energy usage is high, the Peaker Method allows fixed energy-related capital costs to be recovered on a granular, hour-by-hour basis, following the hourly variation in marginal energy costs. It should be noted, however, this procedure does not necessarily ensure that fixed costs are recovered in their entirety.[97]

I used a similar approach in applying the proxy unit method to achieve a reasonable degree of granularity and ensure all of the fixed costs are taken into account. I first classified fixed costs in excess of the fixed costs of the combustion turbine as energy-related, and then took steps to ensure that energy-related fixed costs were largely recovered during times when energy usage is high, rather than at night, when energy usage tends to be lower.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING HOURS OF OPERATION?

A. I assumed the nuclear unit would be dispatched at the bottom of the generating stack, and its energy-related costs would be recovered during all 8,760 hours per year. I assumed the combined cycle unit would be dispatched in the middle of the stack (below the combustion turbine) and its energy-related fixed costs would be recovered over 5,110 hours per year. [98] Finally, the combustion turbine would be dispatched last, since it has the highest variable

97 In practice, the results of the Peaker Method can sometimes understate costs, since there is no guarantee the energy cost estimates and capacity cost components will be internally consistent, or sum to the full incremental cost of building and operating a new generating plant – as they are theoretically supposed to.

98 Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the combined cycle unit will be dispatched approximately 58% of the time, which is reasonably consistent with the overall system load factor.

costs. As discussed earlier in my testimony, I studied multiple dispatch factors; the most interesting and relevant ones assumed the CT was dispatched somewhere in the vicinity of 4 to 5 hours per day, which the proxy unit cost model indicates is near the "cross-over" or breakeven point.[99] Above that point it is cheaper to use a combined cycle plant.

Although somewhat simplified, the approach I used is consistent with the way these different technologies are typically used over their economic life cycle, and it provides a straightforward way of comparing the cost of these different proxy units. However, it is helpful to realize the actual number of hours any given plant will be dispatched will vary as fuel prices change, and it will tend to decline as the plant ages.

Section 5: QF Energy Rates

Q. ARE THERE SPECIFIC ASPECTS OF THE PROPOSED QF ENERGY RATES YOU WOULD LIKE TO DISCUSS?

A. Yes. First, I would like to discuss the Utilities' fuel forecasts, especially Duke's proposal exclusively to use forward market data in developing its proposed QF energy rates. Second, I would like to discuss the Utilities'

99 The exact cross-over point varies slightly, depending on the heat rate of the combined cycle and combustion turbine units, fuel prices and other factors.

proposals to no longer offer fixed long-term energy rates, forcing both QFs and ratepayers to bear the additional risks associated with variable energy rates. Third, I would like to discuss some geography-related issues, including DNCP's proposal to reduce its energy rates based on the historical energy price differences between the DOM Zone and the North Carolina service area.

Q. DID DUKE AND DNCP FOLLOW HANDLE THEIR FUEL PRICE FORECASTS IN THE SAME MANNER?

A. No. There is an important difference in the way DNCP and Duke developed the fuel prices they input into their production cost models to develop their proposed avoided energy costs and QF rates.

In developing its Promod model inputs, DNCP relied on forward market prices for 18 months, followed by an 18-month transition to a fundamental price forecast, which it used for all remaining years.

> For the first 18 months of the forecast period, the fuel, PJM power, and emission allowance prices are based on estimated market prices as of September 29, 2016. For the next 18 months, the prices are a blend of the market prices and the ICF commodity price forecast as of early October 2016. For the remainder of the term (starting October

> 2019), the prices are based exclusively on ICF's commodity price forecast.[100]

DNCP explained this is the same approach to blending market and fundamental data it used in developing the compliance rates in the 2014 biennial avoided cost proceeding.[101]

In contrast, to develop its Prosym inputs, Duke used fuel price data from futures markets for the first 10 years (through 2026), followed by a four-year transition to a fundamental forecast. Beginning in 2031 it exclusively used its Fall 2016 fundamental forecast assuming Clean Power Plan compliance.

Q. WHAT IS A FUNDAMENTAL FORECAST?

A. This is simply the name given to a price forecast that is developed from an analysis of the underlying factors which help explain prices, including supply and demand, technological changes, government policies and other "fundamental" factors.

100 DNCP response to NCSEADR1-13 (d).

101 DNCP response to NCSEADR1-13 (f).

Q. HOW DOES THAT DIFFER FROM FORWARD MARKET PRICES?

A. Forward market data are typically taken from futures markets, where traders are buying and selling specialized legal rights which typically involve the right to purchase or the right to sell a specified volume of a commodity on a specific future date.

These market transactions do not typically result in the actual physical delivery of the commodity, although this is theoretically a possibility. Instead, the market provides opportunities for firms to hedge risks, and for traders to make speculative bets. Market participants are typically largely focused on short term phenomena, like how they think the market will move in response to upcoming market conditions, weather, political events, market psychology, and other factors that influence prices in the short term. The market also tends to be more active, or liquid, for contracts in the relative near future. While price quotes can be obtained for dates farther into the future, that data is not as meaningful or reliable as the market data for the immediate near term.

Q. HAS THE QUESTION OF HOW MUCH WEIGHT TO GIVE MARKET DATA AND FUNDAMENTAL FORECASTS BEEN CONSIDERED BEFORE?

A. Yes. This issue also arose in the 2014 biennial proceeding, and in the 2016 IRP proceeding. NCSEA has consistently expressed concerns about placing too much emphasis on forward market data, particularly over lengthy time periods, and expressed its concerns in the comments it recently submitted in the 2016 IRP proceeding:

> ...it is NCSEA's position that fundamentals-based forecasts in future years are more representative of a utility's avoided cost and that it is not appropriate to rely on ten years of "forward prices" in estimating future avoided cost.
>
> ...The appropriate reliance on fundamental forecast and futures prices, and the appropriate time periods over which these data sources should be used, are issues that are best resolved in the context of the avoided cost proceeding. [102]

In that same proceeding, the Public Staff succinctly restated the history of this controversy, and expressed some concerns with the impact of Duke's approach in the context of avoided cost development:

> In the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, the Public Staff and other parties advocated that the Company return to its previous use of forward prices for the early years of the forecast and then transition to a fundamental forecast developed by energy economists and gas analysts that estimate the future demand and supply of natural gas.
>
> ...DEC and DEP are proposing to use ten years of forwards prices and transitioning to a fundamental forecast for the rest of the 15-year term. The Public Staff notes that DNCP continues to follow the method of using three years of forward prices and then in the 30th month of the forecast, beginning a transition to reliance on the fundamental natural gas forecast developed by ICF. By the 36 th month

102 NCSEA Comments, N.C.U.C. Docket No. E-100, Sub 147, p. 4.

> of the forecast, DNCP has fully transitioned to a fundamental gas price forecast.
>
> The Public Staff further notes that the use of an excessively conservative natural gas price forecast is unlikely to alter DEC or DEP's generation expansion plan; however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs.
>
> ...the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that the Public Staff believes are overly conservative and inappropriate for planning purposes. Instead, the Public Staff finds more reasonable DNCP's approach of using forward price data for the short term before transitioning to its long-term fundamental natural gas price forecast. [103]

Q. SINCE DNCP AND DUKE ARE USING DIFFERENT APPROACHES, IS THIS A MATTER OF LONG-STANDING CORPORATE ATTITUDES TOWARD FUNDAMENTAL FORECASTS?

A. No. In fact, Duke's recent proposals to minimize or completely avoid using their fundamental forecast is particularly striking because it is inconsistent with the substantial level of effort Duke Energy Corporation has historically investing in developing its fundamental forecast data, and because it is inconsistent with its long-standing corporate practice of relying on fundamental forecasts for its internal investment decisions and long term plans.

103 Public Staff Comments, N.C.U.C. Docket No. E-100, Sub 147, pp 82-85.

Furthermore, Duke's recent proposals are even inconsistent with DEC's past practice in developing avoided cost calculations. For instance, in the 2012 biennial proceeding Duke used two years of forward price data combined with 24 months of transitional data that it merged with its long-term fundamental natural gas price forecast, and all subsequent years were based entirely on its fundamental forecast.[104]

104 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 140, December 17, 2015, p. 24.

Q. HAVE YOU LOOKED AT THE FUNDAMENTAL FORECAST DUKE USED IN ITS 2016 IRP FILING?

A. Yes. The fundamental forecast included in Duke's 2016 IRP is shown in light purple in the following graph:

BEGIN CONFIDENTIAL

[redacted]

[redacted]

END CONFIDENTIAL Both are fundamental forecasts are very similar. The Duke forecast is a little higher from after 2035 and it is a little lower between 2020 and approximately 2034.

PUBLIC VERSION

Q. HOW DOES DUKE'S FUNDAMENTAL FORECAST COMPARE TO THE FUEL PRICES IT USED FOR ITS PROPOSED QF RATES?

A. Duke used much lower prices to develop its proposed QF rates in this proceeding. The difference can be seen in the following graph, where the light purple lines show its fundamental forecast, and the darker purple lines show the forward market and "blended" prices it used in this proceeding.

BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL

These lower fuel prices concentrated in the 10-year period which Duke used to calculate its avoided costs, and this resulted in correspondingly lower QF energy rates being proposed in this proceeding.

Q. IS THIS INCONSISTENCY APPROPRIATE?

A. No. Duke Energy Corporation goes to considerable effort and expense to develop its own, comprehensive fundamental forecast of the entire US energy sector, which it updates periodically for use by both the parent and its subsidiaries. This proprietary forecast reflects Duke Energy's view of the long-term outlook for the energy sector, which it uses to make long-term investment decisions by all of its electric utilities.[105]

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

105 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 6.

In practice, while Duke Energy Corporation's utility operating subsidiaries use forward market data for hedging and other near-term operational purposes, they typically rely on Duke Energy Corporation's fundamental forecast for longer term decisions. This was explained by a witness for Duke Energy Florida in a recent proceeding before the Florida Public Service Commission. He explained the fundamental forecast is provided to the fuels procurement group, which uses futures market quotes from the NYMEX to estimate fuel price for the first three years, followed by a two-year transition period of blended prices to the long-term fundamentals.[106] The fundamental forecast is relied upon exclusively for the balance of the planning process. He also explained that the short-term fuels forecast is based on observed market prices, and is used mainly for operational purposes.[107] He also made clear that long-term investment decisions are made by Duke Energy Corporation and its electric utilities based on the fundamental forecast.[108]

Considering the pivotal importance of fuel prices to its internal decision-making process, it's not surprising that Duke Energy Corporation goes to considerable effort to develop and periodically update its Fundamental Forecast. In fact, an outside consulting firm that specializes in fuel price

106 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 12.

107 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 6.

108 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, Exhibit KED-1, p. 6.

forecast modeling and analysis is retained to assist with this process, and these outside experts are required to work with assumptions that are approved by Duke Energy Corporation. Moreover, all of their work is carefully reviewed by internal corporate subject matter experts, to ensure consistency with Duke Energy's own internal planning assumptions and views concerning future changes in environmental policies, load growth, and other variables.[109] Considering how much effort Duke Energy Corporation puts into developing the fundamental forecast, and the magnitude of the investment decisions it makes in reliance on this information, it isn't surprising this witness described the Fundamental Forecast as reflecting both "industry expertise and Duke Energy's expertise and professional judgment of future fuel costs.[110] Nor is it surprising he repeatedly testified on behalf of Duke Energy Florida that the fundamental forecast "reasonably represents future fuel commodity prices."[111]

I am not aware of any instance in which an analogous claim has been made by forecasting experts or authoritative representative of Duke Energy Corporation, or any of its operating utilities, suggesting that forward market prices are superior to their internally developed fundamental forecast for long term investment decisions. To the contrary, this witness warned that futures

109 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, pp 8-9.

110 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 5.

111 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, 14.

PUBLIC VERSION

market "prices are illiquid after the first few years and often do not reflect the impacts of proposed environmental rulemaking, retirements of existing generation, or changes in technology."[112]

Q. DID YOU ALSO LOOK AT DNCP'S FUEL PRICES?

A. Yes. The following graph shows the natural gas prices DNCP used in its Spring 2016 IRP filing in light purple. BEGIN CONFIDENTIAL

[redacted] ND CONFIDENTIAL The two forecasts are quite similar for the first several years, but DNCP's forecast is quite a bit higher in the latter part of the forecast period. It's important to

112 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, Exhibit KED-1, p. 7.

note, however, that DNCP did not actually use this forecast in preparing its QF avoided energy rates. Instead, it used a significantly lower set of fuel prices, as shown in darker purple in the following graph.

BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL

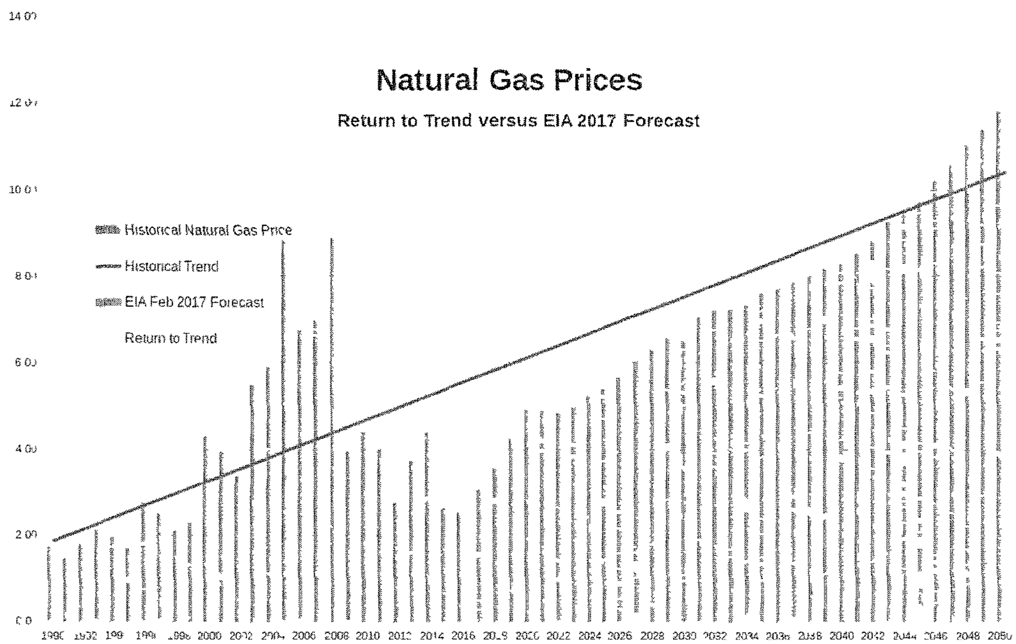
Q. WHAT CONCLUSIONS DID YOU REACH CONCERNING FUEL FORECASTS?

A. Considering how important future fuel prices are to the outcome of these biennial proceedings, it is unfortunate the Utilties have not been more forthcoming in disclosing the assumptions and forecasts they are using. It is also unfortunate they have not provided avoided energy cost estimates using other scenarios concerning future fuel prices. This makes it more difficult for the Commission to evaluate the merits of the forecasts the Utilities used. It also makes it harder for the Commission and other parties to anticipate the impact of correcting problems with the Utilities proposals – for instance, requiring Duke to use its fundamental forecast, or requiring DNCP to use the same fundamental forecast it used in the 2016 IRP.

There are benefits to providing the Commission with avoided cost information that reflects a variety of different scenarios and forecasts obtained from multiple sources. That is one reason why I've presented so many graphs showing different forecasts, including ones taken from public sources, which are not confidential.

That said, I am particularly troubled by the fact that DNCP used significantly lower fuel prices in this proceeding than it used in the 2016 IRP proceeding. I am even more troubled by the fact that Duke essentially ignored its fundamental forecast when developing its proposed QF rates.

Duke Energy Corporation goes to great effort to develop and periodically update its fundamental forecast of energy prices, which it uses for many different long term planning purposes. Both Duke's fundamental forecast, as well as the forecast DNCP used in its 2016 IRP filing, seem reasonable, and both are reasonably consistent with the most recent long term fundamental forecast of natural gas prices that was published in March 2017 by EIA. For convenience, that forecast is shown in the following graph, although it also was discussed earlier in my testimony.



In my opinion, the 2017 EIA forecast adopts a reasonable middle ground. It is also largely consistent with the scenario (shown in yellow) in which prices gradually return to, and then follow along, the long term historical trend (the dark blue line in these graphs). Accordingly, it would be reasonable for the Commission to rely on this neutral, publicly available fundamental forecast as a benchmark for judging the reasonableness of the much lower fuel prices the Utilities used in calculating their proposed QF energy rates. In turn, this suggests it would be reasonable for the Commission to require DNCP to use either the 2017 EIA forecast, or the fundamental forecast it used in preparing its 2016 IRP.

Similarly, I recommend the Commission again reject the use of forward market data for anything more than the near-term future. To the extent some consideration is given to forward market data, I recommend using DNCP's blending approach, which is much more reasonable than Duke's approach in this proceeding. Another option would be to require Duke to use the approach that was described by Duke Energy Corporation's witness in Florida. Forward market data would be used for the first three years, followed by a brief two-year transition period of blended prices to the long-term fundamental forecast of prices, then relying entirely on the March 2017 EIA forecast, or Duke's long-term fundamental forecast, for all subsequent years.

Q. HAVE THE UTILITIES EXPRESSED ANY CONCERNS ABOUT CHANGING FUEL PRICES?

A. Yes. Duke witnesses Snider pointed out that fuel prices have fallen significantly in recent years.

> In general, 10-year (2017 to 2026) levelized natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period as compared to those used in calculating the Companies' avoided cost of energy in the 2014 biennial Sub 140

> proceeding. Compared to the 2012 Sub 136 avoided energy costs, fuel costs have fallen even further with natural gas declining approximately 48% and coal, 33%.[113]

Duke witnesses Bowman pointed out the resulting discrepancy that inevitably arises whenever fuel prices change – the assumptions used to establish fixed QF rates are not identical to subsequent estimates of the variable fuel costs that are avoided by QF power.

> If contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate, no longer mirroring the utility's incremental costs. Thus, long-term contracts with forecasted rates shift the risks of those rates not aligning with avoided costs to the utilities' customers. [114]

Q. DO YOU AGREE WITH THIS STATEMENT?

A. Yes. However, as I will explain later, I disagree strongly with the implication that this is problem that is so serious it needs to be "solved" by replacing fixed QF rates with ones that change every two years.

To the extent the Utilities' witnesses discussed the potential impact of forecasting risks at all, their discussion is oversimplified, and potentially misleading, as exemplified by these comments by Duke witness Bowman.

> long-term contracts with forecasted rates shift the risks of those rates not aligning with avoided costs to the utilities'

113 Snider Direct, p. 16.

114 Bowman Direct, p. 48.

> customers. This shifting of the growing risk to customers becomes increasingly unjust, unreasonable, and contrary to the public interest as greater and greater QF capacity avails itself of these longer-term rates.[115]

In my opinion, the risk of "rates not aligning with the avoided costs" is a less serious problem for ratepayers than the potential adverse consequences of the proposed solution: removing all stability from the QF rates, and adjusting rates every two years. This is a "lose-lose" modification, which increases risks for both retail ratepayers and the QFs.

Furthermore, the risk of a misalignment of QF rates and costs isn't as serious as the analogous risks incurred when the Utilities build and operate their own plants. Both methods of obtaining electricity involve uncertainties. Every time Duke builds a plant using technology A, there is a risk that technology B will turn out to have been the better, more cost-effective choice. While rarely discussed, this misalignment problem is far more significant than the misalignments involved in purchase power contracts, particularly since the latter decisions are made in smaller chunks, allowing a greater degree of cost averaging over time.

The impact of sub-optimal technology choices (in hindsight) can result in a serious misalignment between the actual costs paid by Duke's customers and the lower costs that could have been paid if a different technology or fuel

115 Bowman Direct, p. 48.

choice had been chosen. This is directly analogous to the rate/cost misalignment witness Bowman is concerned about. The difference is that the magnitude of the problem is much larger when looking at the consequences of past technology and fuel choices for the Utilities' own plants.

Q. HOW DOES FUEL PRICE INSTABILITY AFFECT UTILITIES AND THEIR CUSTOMERS?

A. For a natural gas producer, higher prices are a positive, but for the typical gas utility customer, they are a negative. The same directionality applies to electric rates. Higher coal and natural gas prices turn into higher rates and higher electric bills, which hurt consumers – particularly when the rate increase occurs suddenly, or is not fully anticipated.

Before fuel adjustment and purchased power adjustment clauses became common in public utility tariffs, unexpected fuel price increases hurt the earnings of electric utilities, while customers were initially shielded from the problem. Inevitably, however, the utility would be forced to file a general rate case, where the higher fuel costs would eventually harm customers, as well. Lower fuel prices tended to have the opposite effect – mostly benefiting utility earnings, but also helping customers in the long run, if for no other reason than by postponing the need for a general rate increase to pass through increases in other costs.

During the energy crisis of the 1970's, regulators increasingly realized that fuel price risks were not only creating serious problems for electric and gas utilities, but they were also creating problems for their customers. To solve both problems, state regulators introduced complexity into the regulatory process, in an effort to ameliorate some of the short-term risks associated with fuel prices. In many states, regulators agreed to periodically update retail electric rates on a systematic, predictable basis, using fuel adjustment and purchased power clauses or periodic, streamlined rate proceedings. Volatility in utility earnings was reduced, equity costs were reduced and bond ratings were strengthened – all of which helped both utilities and customers.

However, under this system, customers bear all of the risks associated unpredictable, volatile fuel prices over the long run. Aside from increasing reliance on hydro and nuclear power (which have high fixed costs and low variable costs), neither the utility nor regulators can do much to reduce or eliminate the downside risk of higher future fuel prices. Aside from installing more insulation or more energy-efficient appliances, there is not much individual customers can do to minimize these long-term risks, either.

Needless to say, the risks borne by customers are largely one-directional. In most cases customers are unhappy when prices are higher than expected, but they do not mind when fuel prices are lower than expected. While theoretically, a customer who invested in more insulation and installing more energy efficient appliances might be "harmed" because the return on their investment is not as high as they originally anticipated, this downside "risk" is not likely to be of major concern – particularly since they will be paying less for the remaining electricity they continue to purchase.

The fuel price risks borne by the stockholders of incumbent utilities are relatively minor and mostly bidirectional. However, that does not mean fuel price uncertainty doesn't pose major risks for customers. Since fuel price changes are entirely passed through to customers, so they are ultimately borne by customers. Stated another way, because of the fuel and purchased power rate adjustment process, fuel prices no longer have a major, direct impact on quarterly utility earnings. Absent proof of imprudence (which is extremely rare), utilities are largely impervious to even the most extreme long term fuel price related risks. When they make investments that prove to be uneconomic, the burden is borne by their customers.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW FUEL PRICE RISKS ADVERSELY AFFECT CUSTOMERS?

A. Yes. Until very recently, many utilities expected coal prices to be less volatile, and generally remain below natural gas prices (on a per-MMBTU basis). Coal prices were expected to be more stable because ample domestic supplies exist which can be readily obtained using existing mining technology, because mining costs are reasonable and are inherently stable, and because competition in both the mining and transporting of coal was expected to remain vigorous. Furthermore, coal can sometimes be purchased from mining firms under long term contracts that provide a degree of pricing stability. In contrast, natural gas prices are inherently more volatile; oil and gas are sometimes produced in tandem, and their prices are subject to significant geopolitical risks; and most forecasts projected rapidly escalating gas prices over the long term.

In fact, the instability of natural gas prices, and concerns about the potential for drastically higher gas prices over the long term, were two of the most serious disadvantages of using this fuel source to generate electricity. Earlier in my testimony, I mention that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Those anticipated long term fuel price savings help explain why so many utilities have seriously considered or committed to multi-billion dollar investments in advanced coal technologies. For example, according to a report published by the EIA in November 2010, a single unit Advanced Pulverized

Coal plant with 650 MW capacity was expected at that time to have a projected cost in 2010 dollars of more than $2 billion.

A utility that selected this technology would be committing billions of dollars that will end up in rate base and be borne by customers for a technology that only made economic sense under the assumption natural gas prices will be more volatile, and increase to much higher levels than coal over the 30+ year economic life cycle of the investment. This becomes clear when comparing the economics of the coal plant to the natural gas alternative given what was known at the time. The same 2010 EIA report shows the estimated cost of a 400 MW single unit advanced combined cycle natural gas plant was just $412 million. Thus, a utility could have built 5 of these combined cycle plants, with a total capacity of 2,000 MW for the same magnitude investment as a single 650 MW advanced pulverized coal plant. The natural gas option would provide more than three time the capacity (2,000 MW versus 650 MW), and it would be much more geographically diverse.

In hindsight, the coal technology is now looking very burdensome for customers, since it cost so much more than the gas plant, yet gas prices have actually declined, rather than increasing as many experts expected at that time. The technology/fuel price alignment problem is even more serious when it is realized that the natural gas option had a heat rate of 6,430 Btu/kWh compared to 8,800 Btu/kWh for the 2010 era advanced pulverized coal technology.

Q. ARE YOU SAYING IT WAS IMPRUDENT FOR UTILITIES TO BUILD ADVANCED COAL PLANTS?

A. No, not at all. The point I'm making is a simpler one. Duke witness Bowman is criticizing QF power purchases because they haven't saved customers as much money as was anticipated at the time the QF rates were set, because gas and coal prices have not increased as much as projected in past biennial proceedings. But, I don't think this "hindsight" standard is appropriate. I am using the coal technology example to illustrate why I think it is unfair to criticize the solar industry for investments and contracts that seemed reasonable at the time, merely because fossil fuel prices turned out to be lower than expected. I am simply showing the implications of this hindsight-based criticism as it would apply to past decisions between two different fossil fuels.

In fact, a similar, but very costly, problem exists with some of Duke's own coal units. In my opinion, it really is not fair to criticize them for making technology choices that turned out to be sub-optimal, merely because fuel prices have turned out to be lower were than anticipated. This sort of criticism is no more valid than criticizing a portfolio manager for buying stocks that offered diversification or other benefits, just because the price of the stock did not end up increasing as much as hoped. In making this sort of evaluation, it is important to look at how each investment fits into the overall optimization and diversification strategy. The benefits of lower volatility and counter-cyclical characteristics may make a stock a good choice for a portfolio, even if it does not turn out to be as profitable it would have been, if stock market prices had tracked closer to the portfolio manager's original price forecast.

Q. HOW DO FUEL PRICE RISKS AFFECT SOLAR AND SMALL HYDRO?

A. Solar and hydro production offer valuable diversification benefits, because they are almost entirely impervious to fuel price risk. Hence, from a purely economic perspective, the more solar and small hydro production that is introduced into the generation portfolio, the more customers will gain the benefit of a fundamentally lower degree of fuel price risk.

Both hydro and solar production require large investments per kW, but they have very low variable costs per kWh. So, from a customer's perspective, the more solar and hydro used to produce electricity, the less fuel price risk they face.

In this regard, hydro and solar are similar to nuclear generation. Nuclear plants also require large investments per kW and low variable costs, leading to relatively low fuel price risks. In fact, that favorable risk profile has long been one of the major advantages of nuclear generation, helping to explain why customers have benefited from over the long term, even when nuclear projects cost more than originally anticipated. However, it is worth noting that solar has even lower fuel related risks than nuclear production. Nuclear plants use uranium as a fuel source, which introduces a small degree of fuel cost risk when the fuel rods are acquired, and a potentially larger degree of risk when they are ultimately disposed of.

Q. IS DUKE PROPOSING CHANGES TO ITS QF TARIFFS WHICH WOULD CHANGE THE RISK PROFILE FOR SOLAR?

A. Yes. Duke witness Bowman argues that the recent experience with fuel prices and variable energy costs declining, while fixed prices in QF contracts remain the same, has resulted in a problem that needs to be solved.

> One assumption underlying FERC's statement in Order No. 69 is that "in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out" in that QF development would remain essentially constant regardless of avoided cost rates and regulatory circumstances. The enormous recent surge in QFs developments in North Carolina disproves this assumption.
>
> ...long-term fixed rate contracts, and the low threshold to obtain a LEO have resulted in large numbers of solar QFs locking in avoided cost rates in North Carolina for the next 15 years. As discussed, these rates are well in excess of the Companies' actual current avoided costs.[116]
>
> ...the 15-year maximum contract term has resulted in significant overpayment commitments by customers, now approximating $1.0 billion, which far exceed the potential

116 Bowman Direct, p. 47.

> for counterbalancing underpayments for the foreseeable future.[117]

As I explained earlier in my testimony, the $1 billion calculation greatly exaggerates the impact of the recent dip in fuel prices, and it creates a false impression that existing QF contracts will be costlier than power produced by generating units Duke owns and operates over the duration of the QF contracts, when in reality there is almost no risk of this occurring. This calculation compares a snapshot of fuel prices taken at a time when they happen to be unusually low. As fuel prices move higher, the arithmetic will change entirely, since the QF rate will remain fixed and coal and gas prices increase. Furthermore, the calculation is totally misleading, because Duke is comparing "All In" prices for QF power with only a portion of the cost of the power it generates. In addition to fuel costs, customers are paying fixed operating and maintenance expenses, property taxes, depreciation, income taxes, debt service, and other fixed costs associated with Duke's generating plants.

Having identified a perceived problem of having QF rates fixed while fuel costs having unexpectedly declined, Duke proposes to "fix" this perceived problem by fundamentally changing the QF tariff structure, by eliminating fixed tariff energy rates. Under Duke's proposed QF tariff

117 Bowman Direct, p. 48.

> The energy rates will be re-established every two years in future avoided cost proceedings based upon the Companies' then-current avoided costs, as approved by the Commission.[118]

> A structure that adjusts the energy rates at reasonable, periodic intervals throughout the duration of a long-term contract is an effective way to reduce customers' exposure to overpayments.[119]

From the perspective of the QF, this fundamentally changes the economics of solar production. Under the current tariff structure, a QF benefits from a fixed revenue stream that aligns well with its fixed costs. If this proposal is accepted, a stable, predictable revenue stream that aligns well with a cost structure of high fixed costs and low variable costs, will suddenly become highly unpredictable. Not only will the future revenue stream depend on the future course of volatile fuel prices, but it will fluctuate with those prices in ways that are fundamentally unknowable and unpredictable from the perspective of the QF and their financiers, because it will depend on the outcome of litigated proceedings every two years.

Q. IS THIS CHANGE IN RISK STRUCTURE BENEFICIAL TO RATEPAYERS?

A. No, not at all. To the contrary, this change eliminates one of the most attractive features of solar power from the perspective of the customer. Solar

118 Snider Direct, p. 7.

119 Snider Direct, p. 18.

currently brings a degree of pricing stability into electric rates; the benefits of that stability (and risk reduction) would be largely eliminated by this proposal.

In other words, this would be a "lose – lose" proposition for both QFs and ratepayers. It would significantly increase the risks borne by QF developers, making it more difficult or impossible to finance QF projects, and it would simultaneously increase (not decrease) the risks borne by ratepayers. In effect, the proposal would reshape QF purchase power contracts to make them more similar to the inherently riskier structure of most other purchased power contracts.

However, from a QF's perspective, this process of updating the energy rates would be far riskier than a typical purchased power agreement, since prices would be subject to the outcome of biennial litigation, rather than being a numerical function of a published fuel price index. The latter approach is inherently less risky and more predictable and is typical practice in the industry, as Duke witness Snider points out:

> …when contracts are negotiated to purchase power, outside of PURPA, the energy payment terms are generally linked to a real-time fuel price index, and as such, the Companies minimize the risk of the customer paying beyond market energy prices for this power. Thus, the Companies' proposed modification to the standard offer contract structure better aligns the level of risk

> imposed upon customers in PURPA contracts with non-PURPA contracts.[120]

Since most non-PURPA sellers of power are burning fuel, it makes perfect sense for them to seek a pricing structure that gives them the ability to push the risk of fuel price changes forward to the purchasing utility, who in turn pushes the risk forward to their retail customers. While this standard practice is beneficial to the buying and selling utilities, it is not particularly beneficial to the ultimate customer, who ends up bearing all of the fuel price risks. There is no logical reason to expand the scope of this pricing arrangement to encompass power production that doesn't involve burning fuel.

In sum, Duke's proposal artificially suppresses, or masks, one of the most fundamental benefits of solar power production, creating a risky revenue stream where a fixed, stable revenue stream make more sense. Both QFs and retail customers will be worse off if this "lose-lose" proposal is accepted by the Commission.

Q. WHAT ARE THE LOCATION-RELATED ISSUES YOU WANT TO DISCUSS?

A. The Utilities have identified two distinct, but conceptually similar, issues. First, DNCP expressed some concerns regarding the relative cost and value of

120 Snider Direct, p. 19.

power within Dominion's North Carolina service area relative to the DOM zone within the PJM region.

> This historical price data shows that the LMPs in the Company's North Carolina service area are consistently lower than the prices for the DOM Zone as a whole. The energy prices for Option B were 4.4% lower than the DOM Zone prices during the on-peak periods and 4.8% lower during the off-peak periods during these years. All things being equal, the LMPs in the North Carolina area are likely to be even lower in the future as more solar distributed generation ("Solar DG") is added to the Company's system.[121]

In response to this disparity, DNCP is proposing to reduce the QF energy rates by a small percentage, based on historical energy price differences between the DOM Zone and the North Carolina service area.

Second, DNCP witness Gaskill expressed some concerns about the fact that solar generation is increasingly being sent from the local area where it is generated to other neighborhoods. And, in an increasing number of cases, solar energy is flowing through the transmission system out of North Carolina to the DOM zone in PJM.

> Solar DG is a scalable resource that can be located at or near the Company's load. [...resulting] in added benefits such as reduced congestion, mitigated line losses, and, in

121 Gaskill Direct, p.10.

> some cases, improved local reliability over centrally-located generation...
>
> Because of the backflow that is occurring on the Company's system … the benefits of Solar DG – scalability, mobility – are no longer being realized.[122]

In essence, he is expressing concern that the location of solar generating facilities isn't being optimized, and thus some of the potential benefits of having numerous small, widely scattered generating units are not being fully achieved.

> When the amount of distributed generation reaches the point where it exceeds the load on its respective circuit, many benefits (and therefore avoided costs) attributed to the distributed nature of the generation are lost.[123]

This discussion is typical of the Utilities' approach to many of the issues they have identified in their testimony. DNCP witness Gaskill concedes there are significant benefits to society which can potentially be achieved when small generating facilities are distributed throughout the state, injecting energy into the grid at many more locations than in the past, but rather than dwelling on those potential benefits, he focuses on the fact that some of these benefits may not be fully achieved when individual circuits receive so much power from QFs that their energy sometimes flows back through the substation onto the transmission grid.

122 Gaskill Direct, pp 10-11.

123 Gaskill Direct, p. 10.

It is my understanding that he is not claiming this backflow is dangerous or creates any risks for either the substation or the transmission system. Rather, he is simply arguing there are potential benefits to society that are lost when energy flows in this manner.

Q. CAN YOU EXPLAIN THIS CONCERN IN MORE DETAIL?

A. Yes. The closer each retail customer is to the nearest location where power is being supplied, the less opportunity there is for energy losses to occur while the electricity is being moved from the point of generation to the point of consumption. Similarly, energy is lost whenever the voltage is changed. For example, when power is generated at a coal plant in a remote part of the state and sent over a high voltage transmission system to a different part of the state, line losses occur along the transmission path, and when the electricity is stepped down to distribution voltage. In fact, additional losses can also potentially occur when the electricity is sent from the substation over the distribution circuit to the final user.

Historically, the Utilities have provided a small allowance for line losses in the QF rates, but they have never comprehensively looked at all of these potential opportunities to avoid costs. Instead, the Utilities focused on the losses that occur when stepping down the voltage from the transmission system to the distribution system. This is why higher rates are paid to QFs at distribution voltage, rather than transmission voltage.

Many other potential benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs of building or upgrading the transmission system itself, can also potentially be avoided. On DNCP's system, in cases where backflow is occurring, some of these potential savings (and the costs that could potentially be avoided) are not being avoided. From society's perspective, this is unfortunate – costs that could be avoided are not being avoided. But, its important to keep in mind the QF rates have never included an allowance for most of these potential avoided costs.

In the 2014 biennial proceeding, the Utilities did not necessarily dispute the existence of these potential benefits of widely distributed QF generation, but rather they offered various reasons for not including them in the QF rate development process. For instance, the DNCP witness testified that "DNCP does not reflect some asserted benefits in its rates because … the benefits are highly uncertain or speculative; and/or the benefits cannot be realized in the context of a QF, as the utility does not control the development of the facility."[124]

124 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 39.

Confronted with these objections, and having insufficient information to fully evaluate the costs and benefits associated with integrating solar generation into the grid, the Commission decided in in the 2014 biennial proceeding agreed they should not be included in the QF rates, deciding instead that "it is appropriate for the costs and/or benefits attributed to solar integration to be more fully evaluated when future studies and calculation methods have been further developed."[125]

Q. ANOTHER CONCERN IS THAT SOLAR GENERATION HAS BEEN "UNCONTROLLED" SO SOME POTENTIAL BENEFITS OF GEOGRAPHIC DIVERSITY AREN'T BEING ACHIEVED. DO YOU AGREE WITH THIS CONCERN?

A. No. DNCP witness Gaskill expressed concern about the failure to achieve maximum diversity with respect to cloud cover.

> ...for Solar DG, geographic diversity reduces the effect of intermittent cloud cover over any single location. Spreading Solar DG across the Company's service territory therefore improves reliability and minimizes integration costs (such as increased operating reserves and

125 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 39.

> load imbalance charges) and operational challenges, in turn reducing costs for customers. [126]

To the extent optimal diversity is not yet being achieved with respect to cloud cover, this is not a reason to abandon the existing market-driven approach to solar QF investment. Markets can be as effective, or more effective, than a purely administrative process in directing investment to locations where it will be most beneficial to society – assuming adequate information and price signals are provided to market participants.

The inherent ability of market-driven processes to advance the public good has long understood by economists. In fact, this is the essence of Adam Smith's famous "invisible hand" which refers to the way market forces can achieve highly beneficial outcomes for society, despite the fact that each individual market participant is not concerned with helping society, but is merely responding to price signals, incentives and other information in an effort to earn a return on their investment. As an economist, I am convinced that markets can be more effective than purely administrative processes in maximizing societal benefits – provided there is sufficient transparency and widespread distribution of information to market participants.

126 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, pp 10-11.

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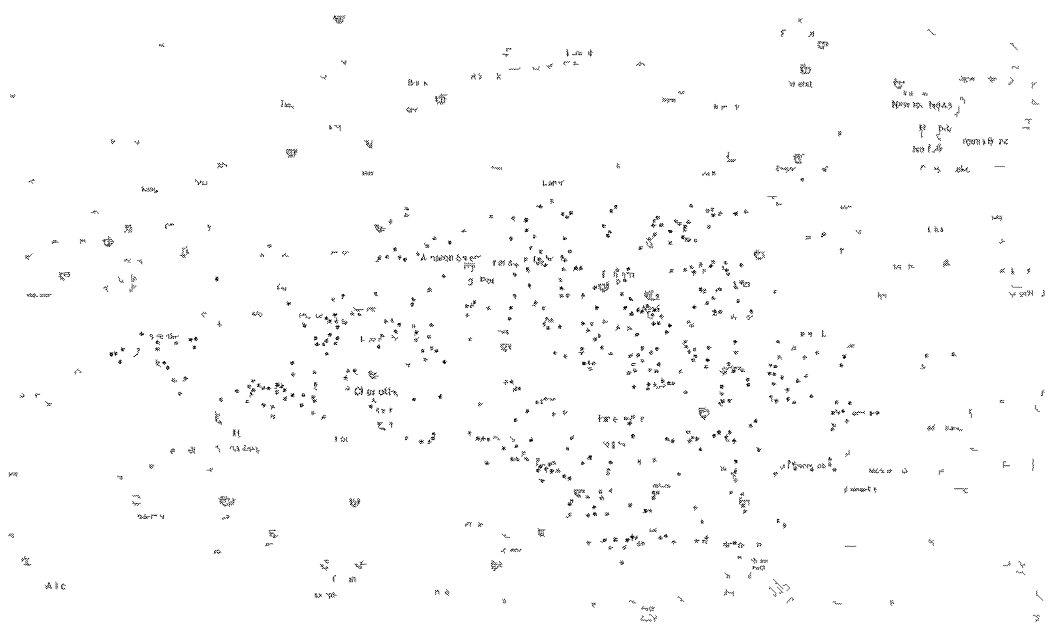
Q. HAS QF DEVELOPMENT IN NORTH CAROLINA BEEN CLUSTERED IN JUST A FEW LOCATIONS?

A. No. To the contrary, solar project are widely scattered throughout the state. In fact, as discussed earlier in my testimony, the state has experienced widespread distribution of small solar projects, which contrasts favorably with the relatively small number of relatively large projects that are being developed in some other states, like Florida and Georgia. This was shown on the US map I discussed earlier in my testimony, and is confirmed on this map, which shows the location of solar facilities connected to both Duke's system (dark blue dots) and DNCP's system (red dots).



The map also shows all 4,600 MW of potential projects that are currently in Duke's queue (purple dots) and projects with a PPA or LEO within DNCP's service area (orange dots).

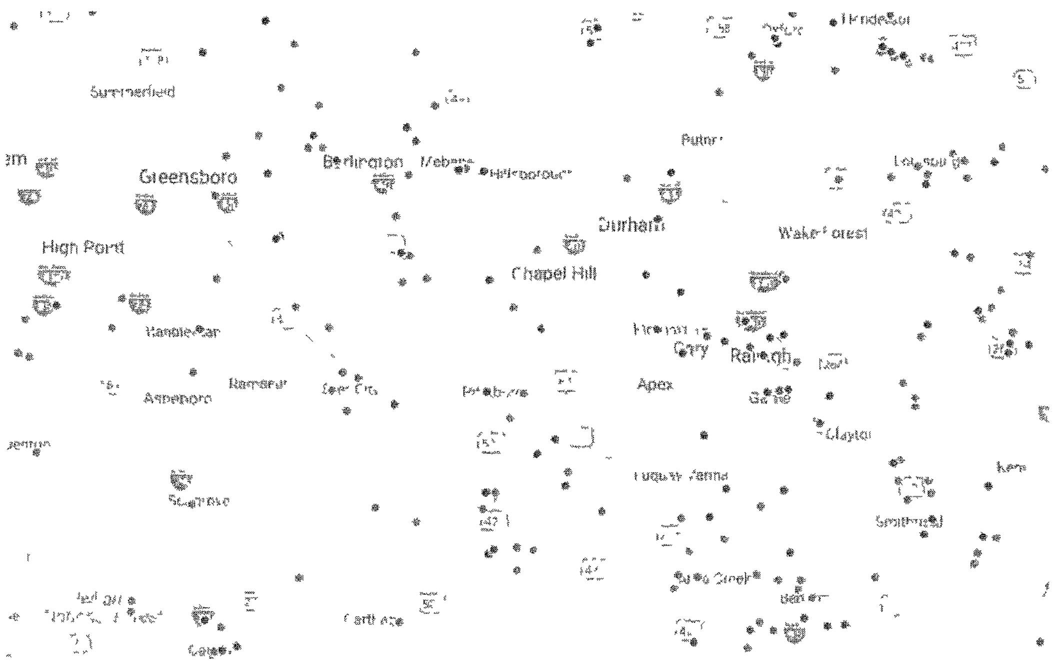
Q. IS DEVELOPMENT UNIFORMLY DISTRIBUTED EVERYWHERE IN THE STATE?

A. No. This follows logically from the fact that it is easier and less costly to develop solar projects away from urban congestion. The same QF rate applies throughout each utility's service area, so there is no revenue-based incentive to incur the extra cost and effort required to permit and build solar facilities in the state's urban areas. Hence it is not surprising that relatively little QF investment is flowing into the state's largest metropolitan area.

α+1

Q. ARE THERE SOLAR GENERATORS IN SOME OTHER URBAN AREAS?

A. Yes. Raleigh, Durham and Greensboro have all attracted some solar investment, as shown below.



Q. DO THE UTILITIES RECOGNIZE THAT QF INVESTMENT IS NOT NECESSARILY BEING OPTIMALLY DEPLOYED?

A. Yes. DNCP witness Gaskill in particular seems to realize the current QF rates do not provide any price signals to encourage more urban investment, or to discourage excessive concentration of QF projects in areas where power is starting to backflow onto the transmission system.

> One of the key limitations with the current manner in which PURPA is implemented in North Carolina is the Company's inability to incentivize QFs to locate in one location over another. This is because all QFs under 5

> MW, regardless of location, are eligible for the same standard contract and rates.[127]

Duke witness Yates made a somewhat similar observation.

> As a general rule, DEC and DEP have historically had little influence on the volume or location of these projects on the utility system. This has created a distorted marketplace...[128]

However, the Utilities did not explore the issue in detail, or provide any suggestions for how their QF tariffs might be improved to "incentivize" QFs to locate in areas where distributed generation is most beneficial.

Q. CAN THE TARIFFS BE IMPROVED TO ENCOURAGE GENERATORS TO BUILD IN SPECIFIC NEIGHBORHOODS?

A. Yes. QF investment is occurring in many locations in the state, but with further refinement, the QF tariffs could provide much more useful and important information about different locations – and the tariffs could even provide corresponding price signals to market participants.

The current system of state wide tariffs combined with ad hoc, site-specific grid integration studies is not ideal from the perspective of either the utility or the QF. For instance, a small power producer is currently forced to invest

127 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 17.

128 Yates Direct, p. 7.

significant time and effort in identifying and acquiring a site without knowing in advance whether it is likely to be good location from the utility's perspective. Only after making this investment does the QF obtain the results of a site study prepared by the utility's engineers, which enables the QF to find out whether interconnection costs will be large or small at that particular site. This is an expensive, cumbersome, and unnecessarily inefficient approach.

Instead, the utility could publish, in their tariff, information identifying all of the substations and feeder circuits where interconnection costs are likely to be above average. The converse could also be communicated. The tariff could list all feeder circuits and substations where distributed generation is anticipated to be particularly beneficial, by enabling the utility to avoid future system upgrades, and the like.

In fact, the tariffs could not only provide better information to QFs, the rate design could be improved to provide more precise price signals that is consistent with that information. Higher avoided cost rates could be paid for in locations where a local power source would be most valuable, and lower avoided cost rates could be paid in locations where local power is not needed, and the power would likely backflow onto the transmission system and be sent to another part of the state. These sorts of improved price signals would be in the best interest of the utility, the QFs and the using and consuming public.

In sum, the Utilities' current and proposed QF tariffs provide minimal information of use to small power producers in deciding where to build more generating facilities, and they set forth highly simplified, statewide average rates. With millions of dollars at stake, there is no reason not to increase the complexity and sophistication of the QF tariffs in order to provide better information to market participants. With a little more effort, the QF tariffs can provide better, more precise price signals, which would help encourage optimal deployment of distributed generation. The end result will be significant benefits for society that more than outweigh the cost of a more complex tariff development process.

Q. WHAT INFORMATION WOULD BE NEEDED TO PROVIDE BETTER PRICE SIGNALS?

A. The tariff development process needs to move past the general discussion of benefits and costs of integrating solar facilities into the grid, as occurred in the last biennial proceeding. Building on the important investigative work the Utilities have recently accomplished in understanding and evaluating solar integration costs in general, the Utilities will have to collect and analyze the detailed factual information they will need in order to list specific locations and provide better price signals in their tariffs.

While the data collection and analysis effort will be significant, the QF tariffs themselves need not change very much. They could simply list two or more rates (analogous to on-peak and off-peak rates), and list the specific feeder circuits, or substations, where those rates are paid. This tariff development process could initially be a collaborative effort involving input from the Public Staff and other interested parties. However, the Utilities are in the best position to collect the needed information, and will need to be at the forefront of this effort.

Once the Utilities are ready to move away from statewide average prices, it will be necessary to estimate how much higher the avoided costs are in locations where a local power source would be most beneficial. Similarly, it will be necessary to estimate how much lower than average the avoided costs are where distributed generation is less valuable. The examples offered in DNCP's testimony concerning locations where power is already backflowing onto the transmission system is an excellent place to start – but more analysis is needed.

In general, the goal is straightforward: to identify locations where distributed generation helps the Utilities avoid distribution and transmission costs, and distinguish those locations from places where distributed generation doesn't avoid these types of costs. The distribution engineers already work with the underlying information that is needed when developing capital budgets and planning for upgrades and replacements of specific portions of the grid. With some reorientation and a longer-term outlook, these engineers can help compile and analyze the information needed to prioritize different locations within the state – helping to identify the feeders and substations where local generation would be most beneficial over the 30+ year economic life of the facility.

Ideally, detailed location-specific information would be developed that considers each of the factors mentions by DNCP witness Gaskill: (1) proximity to load centers and other factors which influence line losses, (2) opportunities to reduce congestion on distribution lines, substations, and transmission lines which could postpone or avoid upgrades to these facilities within the relevant planning horizon, and (3) opportunities to improve local reliability.

In sum, solar generation is being placed all over the state, but there is room for further improvement. Statewide average tariffs are not optimal, and there is no reason not to move toward more a more sophisticated rate design. The QF tariffs can and should be improved, to send better, more precise price signals to the QFs that enable them to weigh the pros and cons of investing in specific locations.

Q. PLEASE SUMMARIZE DNCP'S PROPOSAL TO LOWER THE QF ENERGY RATES BASED UPON PJM LOCATIONAL PRICE DIFFERENCES.

A. According to DNCP witness Gaskill, this proposal is based upon observed differences in Locational Marginal Prices ("LMPs") for energy at different geographic locations within its system.

> PJM calculates the locational marginal price or LMP that reflects the value of energy at each specific node on the grid. Areas in which generation is needed to meet load will realize higher LMPs in order to incentivize generation to locate in that place. Conversely, locations where generation is not as valuable due to congestion and/or losses will realize lower LMPs. ...LMPs in the Company's North Carolina service territory have been consistently lower than the prices for the DOM Zone as a whole.
>
> Lower LMPs mean that additional generation in this area is less valuable than generation in other areas of the DOM Zone.[129]

DNCP witness Petrie describes their proposal to reduce the QF energy rates in response to these observed LMP differentials.

> The adjustment to the avoided cost energy rates is based on the historical energy price differences between the DOM Zone and the North Carolina service area. The Company based its calculated value of energy in the North Carolina area on the average day-ahead LMPs at six locations, which were selected because they are

129 Gaskill Direct, p. 23.

> geographically dispersed, and because they are known to have QF development at or near those locations.[130]

Q. WHAT IS YOUR RESPONSE TO THIS LOCATION-BASED PRICING PROPOSAL?

A. On a purely conceptual level, I have no objection to using LMP data to help refine the QF rates. LMPs may potential relevance to the problem of how best to improve QF price signals, in order to encourage QF power to be generated where it is most valuable.

> PJM uses locational marginal pricing to set prices for energy purchases and sales in the PJM market and to price transmission congestion costs. Congestion is when the lowest-priced energy is prevented from flowing freely to a specific area on the grid because heavy electricity use is causing parts of the grid to operate near their limits. True to its name, locational marginal pricing is based on the location in which the power is received or delivered.
>
> Locational marginal pricing is analogous to a taxi ride for megawatts of electricity. When traffic is light, you can expect a consistent and predictable taxi fare, which would represent a period with little to no congestion on the grid. Similarly, heavy traffic results in a higher fare, which is similar to a time of congestion on the transmission system.[131]

However, significantly more information and analysis needs to be provided so that the Commission and interested parties may evaluate the merits of DNCP's

130 Petrie Direct, p. 9.

131 PJM Learning Center, Locational Marginal Pricing, available at https://learn.pjm.com/three-priorities/buying-and-selling-energy/lmp.aspx (last accessed March 27, 2017).

idea of using location-specific LMP data. More thought is also needed concerning the policy implications of this proposal, as well as the merits of the specific calculations DNCP has proposed. Additional granularity and further refinement of the calculations is likely appropriate.

At a minimum, there are nine issues that ought to be investigated before the Commission decides whether to accept some variation of this proposal: 1) if, on average, North Carolina LMPs have been consistently running about 5% below the DOM Zone average, what are the underlying factors that are causing this differential; 2) how large is the variation in LMPs observed at specific locations within DNCP's system in North Carolina; 3) does the differential at individual locations remain fairly stable, or does it fluctuate significantly over time; 4) is it appropriate to average the differential across DNCP's entire North Carolina service area, or or should more granularity be retained; 5) what are the underlying factors that explain the pattern of LMP differentials; 6) to what extent do the differentials vary in response to changes in these explanatory factors; 7) does generating more QF power near a specific bus impact the observed LMP at that bus, and if so how large an impact is there on the LMP; 8) does generating QF power in North Carolina and sending it to the rest of the DOM Zone have a consistent, predictable impact on the LMP differentials; and 9) if the Commission is going to recognize this differential in developing the QF energy rates, whether it would be appropriate for the sake of consistency to also use the same differential to make a downward adjustment factor to the retail energy rates.

Section 6: QF Capacity Rates

Q. ARE THERE ALSO SPECIFIC ASPECTS OF THE PROPOSED QF CAPACITY RATES YOU WOULD LIKE TO DISCUSS?

A. Yes. I would like to discuss two aspects of the Utilities' proposals that are essentially the same as ones that have been proposed and rejected in the past – the use of zeros in calculating the avoided capacity rates, and reducing the Performance Adjustment Factor ("PAF") from 1.20 to 1.05.

Q. PLEASE EXPLAIN THE PROPOSED USE OF ZEROS.

A. The Utilities are proposing to calculate the avoided cost of capacity as zero during the initial years of their long term fixed rate QF rate calculations. This is the main justification for reducing the proposed capacity rates so drastically.

Difference in QF Rates: Duke Progress Current versus Proposed

	DEC Capacity	DEP Capacity	Average
2014 QF Rate	1.386 cents	1.303 cents	1.345 cents
Proposed QF Rate	0.478 cents	0.573 cents	0.526 cents

Difference	-0.908 cents	-0.730 cents	-0.820 cents
Percent Difference	-65.5 %	-56.0 %	-60.9%

The reason this table does not show any zeros is because the rates have been levelized (15 years for the 2014 rate and 10 years for the proposed rate). DNCP witness Gaskill explains the rationale for using zeros.

> Simply stated, the Company does not have a near-term need for additional generation capacity and, even if it did, additional Solar DG in North Carolina beyond what is already under contract would not defer future capacity needs.[132]

Duke witness Snider explained

> the capacity rates decreased primarily because the Companies do not have an actual capacity need during the initial years of the 10-year contract term period.[133]

Bowman offered a similar explanation for making essentially the same proposal.

> ...the capacity component of the Companies' avoided cost rates recognizes the capacity value of the QF starting in the first year that the Companies' IRPs demonstrate an actual capacity need. The Companies moderate their near term lack of capacity need by levelizing the capacity

132 Gaskill Direct, p. 28.

133 Snider Direct, p. 11.

> component over the 10-year term of the proposed standard contract.[134] Bowman Testimony Page 44

Duke witness Snider further explained this reasoning.

> Avoided capacity costs are represented on an annual basis in a similar fashion to the fixed cost of a car or home being represented as an annual car payment or mortgage payment. To appropriately incorporate the need for capacity consistent with PURPA, the annual fixed capacity costs that go into the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists as determined by the utilities' most recently filed IRPs.[135]

Q. HAS THE COMMISSION PREVIOUSLY DEALT WITH THIS LINE OF REASONING?

A. Yes. The Commission rejected the proposed inclusion of zeros in calculating the avoided capacity rate in the 2014 biennial proceeding. While some of the specifics might differ slightly, the arguments offered in that case are similar to those offered here:

> In support of DEC, DEP and DNCP's proposal to include zeroes in their avoided capacity cost calculations during the early years of the planning horizon, DEC/DEP witness Bowman testified that PURPA was not intended to force utilities to pay for capacity that they do not otherwise need ...DEC/DEP suggest that ...the avoided cost rate should include only the annual fixed capacity costs for years in

134 Bowman Direct, p. 44.

135 Snider Direct, p. 34.

> which an actual capacity need exists as determined by the utilities' most recently filed IRP.
>
> ...witness Petrie asserted that DNCP has all the capacity it needs and that it will not avoid any capacity costs if new QFs commence operation during this time period.[136]

After reviewing the Utilities' arguments in the 2014 avoided cost proceeding, the Commission rejected them:

> It is inappropriate in this docket, when employing the peaker method, to require the inclusion of zeroes for the early years when calculating avoided capacity rates.[137]
>
> The Commission determines ...that the avoided cost rate should [not] be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into.
>
> ...the FERC rejected claims bearing some similarities to the claims made by the utilities in this case, that a short-term lack of need because of a recently built plant justifies not making capacity payments. In Hydrodynamics (146 FERC ¶ 61,193), the FERC explained that avoided cost rates need not include the cost for capacity in the event that the utility's demand or need for capacity is zero. However, the FERC made clear that the time period over which the need for capacity needs to be considered is the planning horizon.
>
> ...Based on the facts of Hydrodynamics, the FERC determined that if a utility needs capacity over its planning horizon, i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity

136 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 32.

137 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 8.

> that would be avoided. The Commission is concerned that including zeroes ...may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. ...It also is significant that the utilities typically are not penalized for having capacity that results in a reserve margin at or above the upper range of what is optimal ...each of the three shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid.[138]

I agree with the decision reached by the Commission in the 2014 proceeding, and I believe it is appropriate to again reject the use of zeros based upon the circumstances of this proceeding.

Among other reasons, I believe the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of "incremental cost" and "avoided cost." Furthermore, the use of zeros is inconsistent with the concept of "ratepayer indifference," and it leads to undue discrimination against small power producers.

138 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 35.

Q. WHY ARE ZEROS INCONSISTENT WITH THE GOALS OF PURPA AND THE CONCEPTS OF INCREMENTAL COST AND AVOIDED COST?

A. If zeros are used, small power producers will not be fully compensated for their capacity. This is inconsistent with the goal of encouraging expanded use of biomass, solar and other targeted technologies which have long been neglected by the electric utility industry. Needless to say, refusing to pay for QF capacity is also inconsistent with the goal of encouraging investment in small power producers, making it harder small power producers to expand and exert competitive discipline on the incumbent firms.

In general, the goals of PURPA and the interests of society as a whole, including the using and consuming public in North Carolina specifically, are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. More specifically, QF avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added.

Because of economies of scale, large utilities find it cost effective to construct very large plants. These plants are so large, they only need to be added at multi-year intervals. For example, assume the utility decides the optimum size plant is 600 MW or larger. If the utility needs to add capacity at the rate of 100 MW per year, it will not add a 100 MW plant every year. Instead, it will add a 600+ MW plant in a single year, then wait 5 or 6 years before adding another 600+ MW plant, then wait another 5 or 6 years before adding another 600+ MW plant. Under these circumstances, economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others.

This stair step pattern (which economists call "lumpiness") shows zero physical need for new capacity in most years. But, the utility is constantly growing and its older plants are slowly becoming costlier to maintain and operate as they gradually near retirement. Given these circumstances, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled for commercial operation.

This stair-step pattern with zeros is typical of the electric utility industry and it is descriptive of the actual generation expansion plans of DEC, DEP and DNCP. Accordingly, we know from economic theory that absence of a need for new capacity during some years (zero MW added) does not mean capacity has an economic value of zero or a long run incremental or avoided cost of zero during those years.

Q. HOW DOES THE PROPOSED USE OF ZEROS DISCRIMINATE AGAINST SMALL POWER PRODUCERS?

A. PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers."[139] Under rate base regulation, the incumbent utilities are allowed to recover the cost of large new generating plants as they are completed and put into commercial operation (allowance for funds used during construction is accrued prior to that time), even though some of the capacity is being added prior to the time it is required (due to lumpiness). The QF rates should give QFs similar treatment – small power producers should be paid for the energy and capacity they provide to the utility as as each new generating plant is added to the grid. Capacity payments should not be held to zero until the first year when the incumbent utility plans to add a new generating plant.

Stated a little differently, since the incumbent utility is allowed to recover its capacity costs during the "zero" years just after a lumpy new plant has been added and its reserve margin is higher than the required minimum, to avoid discrimination, the QF should be treated the same – it should also be paid for capacity costs during the "zero" years, even though the QF capacity has the effect of pushing the reserve margin a little higher above the required minimum.

139 16 U.S.C. § 824a-3(a).

The simplest way to avoid discriminating against QFs is to ensure they are paid full capacity costs during every year, consistent with the long run incremental cost of building and operating new generating plants over their entire economic life cycle. Properly implemented, this long-run measure of avoided costs ensures that retail ratepayers pay the same amount for QF power that they are paying for power produced by the Utilities– no more and no less.

Q. Q. WHAT IS DUKE PROPOSING WITH RESPECT TO THE PERFORMANCE ADJUSTMENT FACTOR?

A. Consistent with its position in the 2014 biennial proceeding, Duke once again proposes to

> Reduce the performance adjustment factor ("PAF") from 1.20 to 1.05 to more appropriately align capacity payments to QFs under the peaker methodology with the availability of the avoided capacity resource, which is a combustion turbine ("CT").[140]

The same issue was debated in the last biennial proceeding.

> DEC/DEP witnesses Bowman and Snider testified that DEC and DEP are proposing to reduce the PAF to 1.05 to align its application better with the reliability of a natural

140 Snider Direct, p. 5.

> gas CT, the unit which the QF is presumed to avoid under the peaker method.[141]

To be clear, the issue in dispute is not what PAF represents the number of hours a CT is available each year. Rather, the issue is whether the PAF should be based upon CT availability or should it be based upon a broader interpretation of the purpose that is served by this factor.

Under the Peaker Method as historically interpreted and implemented by this Commission, it is more appropriate to focus on availability data for a<u>ll types of units</u>, including coal units and combined cycle units. Consideration needs to be given to the performance of all baseload generating plants because these are the units that produce the energy reflected in the avoided energy cost calculations. Similarly, consideration needs to be given to the entire life cycle of these units, including data showing the performance of older, less reliable units which are nearing retirement.

Q. PLEASE EXPAND UPON YOUR REASONING.

A. In the Peaker Method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units. Hence, I believe the availability of other types of generating units (e.g.

141 <u>Order Setting Avoided Cost Input Parameters</u> N.C.U.C., Docket No. E-100, Sub 140, December 31, 2014, p. 54.

coal and combined cycle units) must be considered, contrary to the narrower viewpoint expressed by the Utilities.

In this regard, I find persuasive the points made by Public Staff witness Ellis in the last biennial proceeding:

> Public Staff witness Ellis described the PAF and its history and noted that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constitute the utility's avoided capacity costs.
>
> ...He stated that a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83 percent of the on-peak hours. He noted that the Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.
>
> ...Witness Ellis testified that the Public Staff believes that the reduction of the PAF to 1.05 as proposed by the utilities is unjustified. The Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. He stated that performance at that level is commensurate with a baseload plant under any definition. He further stated that none of the data provided or arguments made is persuasive to justify a departure from that conclusion. In this regard, it should be considered that when the capacity factors reported by the utilities in their monthly baseload power plant performance filings are averaged over the last three calendar years, none of them operated their baseload fleet at an 83 percent capacity factor, which is the relevant statistic for comparison because QFs are paid for capacity

> on a kWh basis. For the calendar years of 2011, 2012, and 2013, the baseload plants in the rate bases of DEC, DEP and DNCP averaged capacity factors of 75.67 percent, 74.52 percent, and 74.83 percent, respectively, while recovering all of their capacity costs through rates.[142]

While the precise calculation of the PAF can be disputed, the key point is that QFs are supposed to be treated in a non-discriminatory manner, consistent with the treatment afforded the Utilities. Achieving a reasonable degree of consistency is also important because QF rates are supposed to leave customers financially indifferent between purchases of QF power and the construction and rate basing of utility-built resources.[143]

Retail customers are paying for all of the Utilities generating units, including ones that only operate a few hours of the year, and ones that are not available when needed during the peak hours, due to scheduled maintenance and other factors. This consistency should be viewed from the perspective the entire life cycle of the unit, not just the first few years after it is built when reliability is at its peak, and maintenance requirements are low. As units age, more maintenance may be required, more outages may occur, reliability may

142 Order Setting Avoided Cost Input Parameters, N.C.U.C., Docket No. E-100, Sub 140, December 31, 2014, p. 55.

143 See, e.g., Southern Cal. Edison, San Diego Gas & Elec., 71 FERC ¶ 61,269 at p. 62,080 (1995) (noting that "the intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives").

decline, and it may no longer be cost-effective to operate the unit 24 hours a day all year long.

The key point is that retail customers pay the full cost of owning and operating the Utilities' older units as long as they remain in the rate base, regardless of how often they are down for maintenance, or how infrequently they are operated. Hence, to meet the standards of ratepayer indifference and non-discrimination, it is necessary to remember that customers are pay the full ownership-related costs of Duke's generating units, regardless of how few hours they produce electricity during any given year. In contrast, the QF only receives capacity payments when it is producing electricity.

Reducing the performance adjustment factor to 1.05 would have the effect of requiring a QF to produce at full capacity during 95% of the on peak hours in order to receive full payment of the avoided capacity costs. For instance, a solar generator would not receive full payment of the avoided capacity costs, because it is incapable of generating electricity during 95% of the on peak hours due to the fact that many on peak hours occur when the before the sun rises or after the sun sets.

It is important to remember that Duke is not being held to this high a standard—i.e., 95%—for its fossil-fueled plants. For example, Duke has coal fired units that were designed and intended to be operated at full load during all of the peak hours. Yet, these units are not producing this much energy under current conditions – some coal units are now being dispatched like intermediate units, instead. The end result is that ratepayers are paying a very high amount per kWh for these units, since their fixed costs are being spread over a unexpectedly small amount of energy output. If Duke were held to the same standard as QFs, it would only receive payment for the portion of its fixed costs that could be recouped from the limited amount of energy the units are actually producing during the on peak hours. The PAF is an important element of the Commission's implementation of the Peaker Method, since it helps ensure a reasonable level of compensation to QFs, notwithstanding the fact that their capacity related revenue is tied to the amount of kWh that is produced over a broadly defined on peak period.

Section 7: Operational Concerns and QF Rate Design

Q. ARE THERE ANY OTHER ASPECTS OF THE UTILITIES' RATE PROPOSALS THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. I would like to discuss their proposals concerning seasonality and hourly cost variations, particularly as these relate to the operational challenges and concerns that have been identified by the utilities.

Q. WHAT ARE THE UTILITIES PROPOSING WITH REGARD TO HOURLY COST VARIATIONS?

A. DEC, DEP and DNCP are all proposing to retain their existing on peak and off peak hours. As a result, the Utilities are proposing to continue to use very broadly defined time periods. This is anomalous, since Duke and DNCP also go to great effort to identify and describe various concerns they have related to the growing volume of solar energy that is being generated during certain hours of the day – during specific parts of the year.

Q. WHY IS THIS ANOMALOUS?

A. Because many of the problems they are describing are so clearly time-related, it is surprising they are not looking for solutions that are specific to these time periods. As an economist, it strikes me as completely anomalous to hear about a time-specific problem, yet no effort is being made to solve the problem in a time-specific manner. In fact, the first thing that comes to mind when I hear about a time related problem is to see whether improved price signals can solve the problem, or at least ameliorate it.

For example, the classical economic solution to highway congestion is to charge a time-variant price for use of the highway during peak hours. I recall hearing this example in one of my first undergraduate courses in economics in the 1970s. The professor explained that society was wasting the time of drivers who were stuck in traffic, and wasting millions of dollars of their taxes constantly building more and more highways, with more and more lanes, just because we were not send the correct price signals.

The solution is to improve prices signals as necessary in order to avoid wasting everyone time sitting in traffic. Ideally, the highest price is charged during the busiest hours, lower prices are charged during moderately busy hours, and a very low (or zero) price is charged late at night and during weekends when the highways are empty.

By charging a higher price during rush hours, some of the people will start to drive at an earlier or later time (or wait until the weekend to run their errands). Improved price signals, or creating price signals where they are entirely lacking, has the predictable result of encouraging people to voluntarily car pool, or modify their work hours to avoid the peak hour. Simply by sending better price signals, much of the congestion may go away. But, to the extent the peak hour continues to be congested, the money collected from the rush hour price can be used to pay for more lanes and more highways – neatly solving the remainder of the problem without having to raise taxes on people who don't drive during the rush hour.

Years ago, many non-economists were not familiar with the benefits of improving price signals. But, now everyone is at least somewhat familiar with the concept. For instance, some cities and states are using computers to adjust highway tolls multiple times each day, in response to operational challenges and concerns that have been identified by the utilities' response to traffic patterns. Now that human toll collectors are not required to collect the fee from frequent drivers, it is effortless for everyone involved to calculate and collect at different prices at different times – sometimes even adjusting and posting notice of the price on a fluid basis in response to real time conditions.

It is increasingly common to see variations on this approach in many different industries – from movie theaters to airlines. Most people are at least vaguely aware of the fact that the airline industry is constantly improving and refining their pricing methods in an effort to maximize the yield every time a plane takes off – and too keep the planes filled nearly to capacity, 24-hours a day.

Hence, it is somewhat anomalous that Duke is proposing multiple, broad brush changes to their QF tariffs which will greatly increase the risks faced by small power producers and discourage investment in solar energy, yet they have not proposed any changes to more precisely tailor their QF rates or improve the price signals being sent to small power producers.

Q. WHAT ARE THE UTILITIES PROPOSING WITH REGARD TO SEASONS?

A. As with the hourly rates, they are not proposing any improvements to the seasonal aspect of their rates. Duke, however, is proposing to change the allocation of capacity costs between the summer and non-summer seasons. Duke witness Snider explains the rationale for this proposed change.

> In the past, the Companies' annual peak demands were projected to occur in the summer. Additionally, the Companies' generating fleets have greater output during winter periods compared to summer periods, particularly for gas-fired CT and combined-cycle units. ...Thus, summer load and resources have driven the timing need for new resource additions, and a summer reserve margin target provided adequate reserves in both the summer and winter periods and was sufficient for ensuring overall resource adequacy.
>
> The load and resource balance has changed drastically in the past two-three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. As discussed in more detail later in my testimony, solar resources contribute significantly more to the summer afternoon peak than they contribute to the winter morning peak. As such, the 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. Thus, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load

> and resources now drive the timing need for new capacity additions.[144]

Based on this reasoning, Duke is proposing to allocate 20% of the avoided capacity costs to the summer (June through September) QF months. The other 80% will be allocated to the remaining non-summer months (October through May). This is a drastic change from the last biennial proceeding, where Duke gave 60% weight to the summer and 40% weight to the non-summer months.

Q. WHAT IS YOUR RESPONSE TO THESE PROPOSALS?

A. I recommend the Commission reject the proposal to give 80% weight to the non-summer months. As well, I recommend the Commission initiate steps to provide stronger, more precise peak and off peak price signals in the QF tariffs. These steps do not necessarily need to be completed in this proceeding, but there is no question in my mind that this is the direction the Commission should be heading.

Stronger, more precise price signals are needed, which are narrowly tailored to carefully identified hours during the summer and deep winter months. The price signals that are optimal during a hot summer day and a cold summer morning are conceptually similar, but the hours are different. The price signals that are optimal during other months of the year, when the weather is

[144] Snider Direct, pp 22-23.

much milder, are very different. The one constant across these different seasons is that the hourly rates need to be more precisely defined, and better, more meaningful price signals sent to small power producers, to encourage them to provide more of their power when it is most valuable, and less when it is least valuable. Among other benefits, improved price signals will help to ameliorate or prevent problems that might otherwise arise as a larger and larger percentage of the energy supplied to the system comes from solar facilities of all types (including those owned by the Utilities, individual retail customers, and QFs).

More precise price signals are a superior solution to many of the concerns the Utilities have identified which are related to, or directly attributable to, growth in solar energy. Among other benefits, if the utilities continue to resist adopting technology-specific rates, there is a mechanism in place that can ensure that small power producers that use wind, methane derived from landfills, hog or poultry waste and non-animal biomass are not penalized for problems (or perceived problems) that are specific to solar energy. Unless the rate design is improved, changes that are made to the standard offer rates in response to solar-specific concerns (whether implicitly or explicitly) have the potential to impose massive "collateral damage" on all other types of QFs.

If the Commission is concerned about the potential impact of "operationally excess energy," then its response should be tailored in a way that targets that specific concern and avoids adopting changes that broadly and unfairly impact all types of QFs. This is particularly obvious with respect to the operational concerns that have been identified by the Utilities, including the growth of what they call "operationally excess energy" which only occurs during specific hours of specific months, but the same principal applies generally. Before the Commission takes drastic steps to slash rates paid to QFs or make those rates less predictable, thereby making it much harder to finance QF investments, it should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified.

Q. CAN YOU PROVIDE THE COMMISSON WITH DATA THAT EXPLAINS WHY YOU DISAGREE WITH ALLOCATING 80% OF CAPACITY COSTS TO THE WINTER?

A. Yes. The following chart is derived from a detailed analysis of hourly load data for DEC and DEP for the years 2006-2015, as filed by the utilities at the FERC on FERC Form 714.

The hourly load data indicates that approximately 86.5% of the most extreme system peaks (at or above 99% of the annual coincident system peak) occurred during the months of June through September, while the remaining 13.5% occurred during the months of December, January and February. None of these extreme peaks have occurred during any other months. A very similar pattern is reflected in the data for peaks of less extreme magnitude, as shown in the following table.

Magnitude of Peak	June - September	December - February	Other
Hourly Load +> 99% of Annual Peak	86.5%	13.5%	0.0%
Hourly Load +> 97% of Annual Peak	90.3%	9.2%	0.6%
Hourly Load +> 95% of Annual Peak	90.4%	9.0%	0.6%
Hourly Load +> 90% of Annual Peak	90.4%	9.0%	0.6%

This data is entirely inconsistent with Duke's proposal to allocate 80% of the capacity costs to a broadly defined non-summer period that starts in October and ends in May. If the Commission is going to move away from the 60% Summer 40% Non-Summer allocation percentages that were used in the last biennial proceeding, then any movement should place more emphasis on the hot summer afternoons and less emphasis on months like October, November, April and May – when extreme peaks almost never occur.

Q. WHAT DO YOU RECOMMEND WITH REGARD TO SEASONS?

A. Ideally, the QF rates would distinguish between three distinct seasons. 80% of the capacity costs would be allocated to the months of June through September, and recovered during the hot afternoon peak hours. The remaining 20% would be allocated to the months of December through February and recovered through the cold morning hours. The remaining months (October through November and March through May) tend to have the mildest weather, and hourly peak variations are not as extreme. Hence the QF rates in those months would ideally be designed differently, taking this into account.

I prefaced those comments with the word "ideally" because I do not think it is of critical importance to resolve this issue at this time. I recognize the Commission has many issues to work through and want to make clear that simply retaining the 60% summer/40% non-winter allocation that was used in the 2014 proceeding would also be an acceptable approach. That would avoid moving in the wrong direction and provides a reasonable basis for evaluating other, higher priority issues, like specific hours that are defined in the QF tariffs.

Q. **CAN YOU ALSO PROVIDE THE COMMISSION WITH SOME DATA THAT SHOWS WHY YOU THINK THE PEAK AND OFF PEAK PERIODS SHOULD BE DEFINED MORE NARROWLY?**

A. Yes. I also studied in considerable detail the same load data taken from DEC and DEP's Form 714 submitted to FERC for the years 2006-2015 to see if clear, more precise hourly patterns in the data can be identified. This detailed analysis of more than 175,000 hourly data points confirms the obvious: peak

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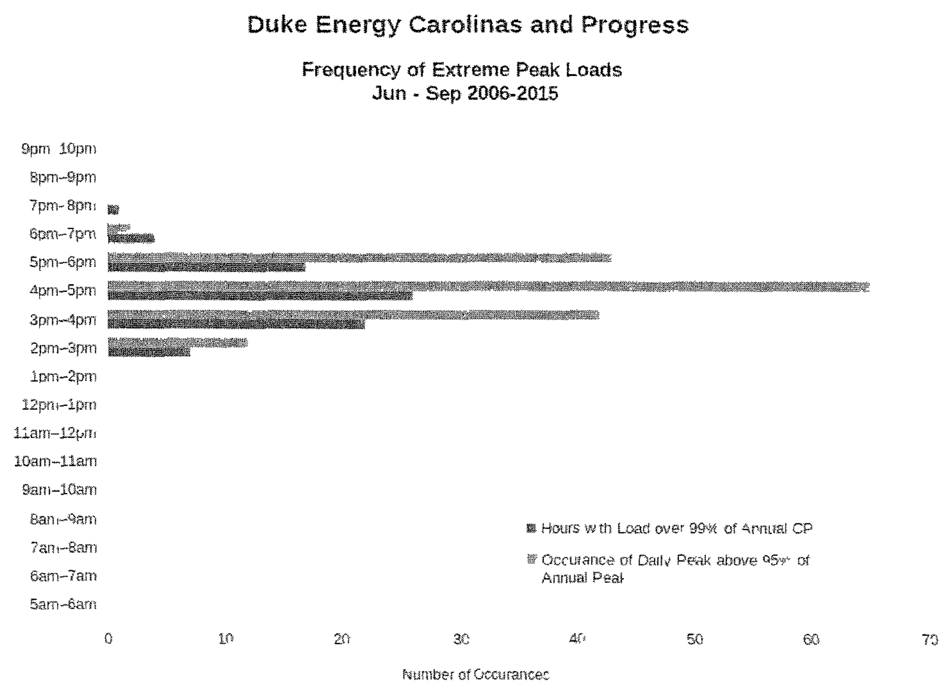
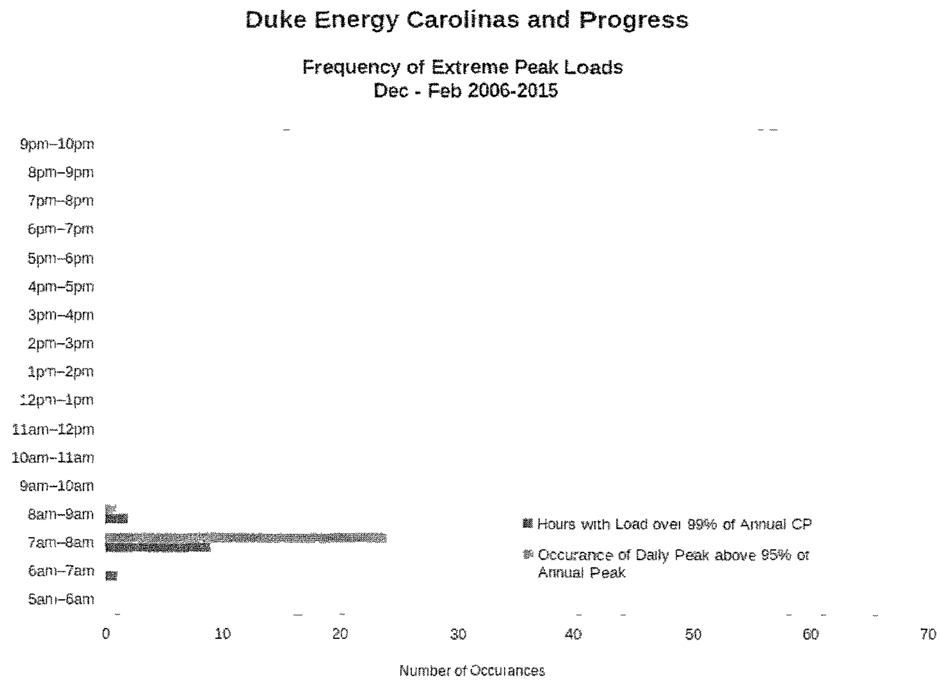
loads on Duke's system are highly weather sensitive, following some straightforward, predictable patterns.

In this first graph, the dark blue bars indicate the frequency when loads above 99% of the annual system coincident peak occurred. The green bars indicate how often the maximum daily peak occurred during a given hour during days when the daily peak was above ~~90%~~ 95% of the annual peak.

4-20-17



This data demonstrates the most highest, most important extreme peak conditions occur on hot afternoons in the summer, from approximately 2:00 p.m. until 6:00 p.m. The next graph shows the analogous data for the months of December, January and February.



Since all of this data is from the same source, and the scales are the same, it is readily apparent that the only remaining peak hours of any major importance are those that occur in the early morning hours of December through February. In most years, these peaks occur less frequently, and are less severe than those that occur during hot afternoons in the summer.

Two important exceptions occurred during 2014 and 2015 when some extreme needle peaks were briefly experienced under severe cold "Polar Vortex" weather conditions. These peaks actually exceeded the annual summer peaks in those years. However, it would be a mistake to overreact to these brief peaks. While they are important, and help justify allocating a reasonable share of total capacity costs to the months of December through

February, the basic pattern remains unchanged: the most important non-summer peaks all occur on cold early mornings in just three months of the year. All other hours, and all other months are of drastically less importance when deciding how to shape the QF price signals.

Even under those years, however, the extreme peaks that occurred on winter mornings were different than those that occurred on summer afternoons – they were both of shorter duration, and less frequent. All of these observations can easily be confirmed by studying the following graphs which summarize the hourly load data.

Q. WHAT CONCLUSIONS HAVE YOU REACHED BASED ON THE HOURLY LOAD DATA?

A. The most extreme system peaks (at or above 99% of the annual coincident system peak) tend to occur during June through September in the late afternoon, around 4 p.m. The late afternoon is also when the maximum daily peak almost invariably occurs on days when the daily peak is at least 90% of the annual system peak. The existing QF rate design is not adequately tailored to this pattern, since it establishes an overly broad on-peak period which dilutes the price signals and fails to inform small power producers when their capacity is most valuable.

To provide stronger, more precise summer price signals, I recommend narrowing the on peak period to the four hours from 2:00 pm until 6:00 pm during June through September. If a more complex rate design is acceptable, an adjacent "shoulder peak" period could be identified starting an hour earlier (at 1:00 p.m.) and extending two hours later (8:00 pm).

A similar, even more severe problem exists with the non-summer rate design. In reality, all of the highest, most important non-summer peaks tend to occur in the early morning around 8 a.m. during December, January and February. The current rate design completely fails to convey this important price signal to small power producers. Instead, it provides the impression that their capacity is equally valuable during many other hours and months.

To provide stronger, more precise non-summer price signals, I recommend limiting the on peak period to the two hours from 7:00 am until 9:00 am during December through February. If a slightly more complex rate design is acceptable, a "shoulder peak" period could be identified that starts an hour earlier and ends an hour later. The rate during these shoulder hours would be modestly higher than during the off peak hours, but substantially less than the rate that applies during the on peak hours.

Q. CAN YOU PROVIDE SOME FURTHER EXPLANATION OF YOUR REASONING BEHIND THESE RECOMMENDATIONS?

A. Yes. It is logical to recover most of the capacity-related costs around the time when the most extreme peaks have the greatest probability of occurring. However, it would be a mistake to recover the entirety of the capacity-related costs from a single hour of each year, or even during a single hour of each day, since capacity also has value during other hours, when there is moderate probability of extreme peaks occurring.

Needless to say, the precise hour when the system peak will occur during any given year (or during any given day) cannot be known in advance. The same thing can be said with respect to the summer and winter peaks. It would be a mistake to treat cold winter mornings as irrelevant, since the peaks during those times reach 90% of the annual system peak on a fairly frequent basis. As well, there are times when the weather is cold enough that an even more extreme peak occurs which approaches or even briefly exceeds the sort of extreme peaks that are much more frequently and routinely observed during hot summer afternoons.

Capacity is most valuable during the hours when the greatest probability of high system peak occurring, but capacity value is not limited to the one or two most extreme peaks that occur during any one year, or any single decade. Thus, for example, it would be a mistake to focus the price signals exclusively on the early morning hours merely because extreme needle peaks sometimes occur at that time – for instance during a Polar Vortex.

The approach I am recommending provides a reasonable balance by sending much stronger, narrower price signals, while avoiding the mistake of over-reacting to extremely unusual weather events, or treating the single annual peak as the only hour having any importance.

Accordingly, given the load characteristics of the DEC and DEP systems, it is reasonable to assign the bulk of the avoided capacity-related costs to summer afternoon hours when the extreme peaks have the greatest probability of occurring, to assign a lesser portion of the capacity-related costs to "shoulder" hours before and after that critical time period, and to assign the remaining costs during the months of December through February, especially in the early morning from 7 a.m. to 9 a.m., which is when "needle peaks" occasionally occur during extreme cold snaps.

Q. WHAT ARE THE OPERATIONAL CHALLENGES AND CONCERNS YOU MENTIONED EARLIER?

A. Both Duke and DNCP express some concerns about the rapid growth in solar energy, which is posing some new challenges for them. Duke witness Yates testifies that:

> [T]he continuing surge in utility-scale solar QF generation is increasingly challenging how the Companies plan and operate their generation fleets, manage their transmission systems, and assure reliable power is delivered to our customers over local distribution circuits on a minute-by-minute basis. Unless thoughtful solutions are implemented to address the current situation, the number, severity, and consequences of these challenges are expected to increase as the level of variable and non-dispatchable solar energy increases.[145]

Duke witness Holeman succinctly described Duke's main concerns, when he testifies that:

> Based on this continuing, rapid growth over the past 18 months and the associated operational experience in accordance with NERC's reliability requirements, the Companies have identified the following challenges associated with integrating these significant levels of PURPA solar: (i) managing "unscheduled" and "unconstrained" solar QF energy injections bounded by the Security Constrained Unit Commitment of reliable load following service; (ii) managing the variability and intermittency of solar energy injections; (iii) managing the growing amounts of operationally excess energy injected by solar facilities, particular during the spring, fall, and winter periods; and (iv) ensuring compliance with NERC

145 Yates Direct, p. 9.

reliability standards, specifically including the BAL standards.[146]

Q. DO YOU AGREE THESE ARE LEGITIMATE CONCERNS THAT NEED TO BE RESOLVED?

A. Yes. Some operational challenges and concerns are unavoidable and inevitable during any major transition in an industry. Regardless of whether the changes are resulting from technological innovations, shifting cost curves, industry restructuring, competitive forces, or any other source of fundamental changes to the way an industry has historically operated, it is important for industry participants to be aware of the changes and develop appropriate, timely responses.

In this case, the challenges and concerns Duke has identified are a result of the success of decades-long efforts by state and federal policy makers to encourage a shift toward increased use of solar and other renewable energy sources, as part of an "All of the Above" strategy. Rather than thinking about these challenges as indications something is going wrong, it is more appropriate to view them as "growing pains" that are occurring as solar energy is finally becoming more cost effective, and it is starting to create fundamental

146 Direct Testimony of John Samuel Holeman III on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Holeman Direct"), p.10.

economic dislocations, as it begins to partially displace coal and other historically vital energy sources.

Of course, the fact that this shift toward a more diversified energy mix has long been sought by state and federal policy makers doesn't change the fact that the transition period can be difficult. Changes of this importance and magnitude will require appropriate managerial, operational and strategic responses by many parties, but most especially by the incumbent utilities. Since this is a regulated industry, it is also vitally important for the Commission to be aware of the changes that will increasingly be taking place as solar grows in importance.

Q. DO THESE CHALLENGES CREATE A CRISIS WHERE A QUICK RESPONSE IS ALMOST MORE IMPORTANT THAN THE CORRECT RESPONSE?

A. No. While solar is growing, it is starting from a small base. As I noted earlier, Duke Energy Corporation reported that Solar provided well under 1% of its total generation during 2016.[147] The challenges are being identified early, while the impacts are still quite manageable.

147 Duke Energy Corporation, 2016 Form 10-K, Page 12.

Q. DO YOU AGREE DUKE'S PROPOSED RESPONSES?

A. Duke does seem to be starting to think proactively about potential solutions to some of these challenges, or at least it is starting to think about the implications of growing amounts of solar on other aspects of its decision-making process. For example, Duke witness Snider testifies as follows:

> ...increasing levels of variable unscheduled and unconstrained solar QFs may create an incremental need for faster response load following generation to meet system loads when solar generation either increases or decreases rapidly. In fact, the Companies have already added or are proposing to add more flexible resources to the system, such as fast-start CTs at Sutton, runner upgrades at Bad Creek Pumped Hydro Station, dual fuel optionality at Cliffside, and the recently announced expansion at the Lincoln County CT site. While increasing levels of solar on the system may not have been the primary driver for these projects, the operational flexibility these projects provide has value given the increasing levels of solar on the system. As more non-dispatchable solar is added, additional flexible resources of all types may be required to reliably manage system operations.[148]

Some solutions – like adding more quick start, flexible generation – seem intuitive, logical, and very likely will prove to be beneficial. However, some of the other solutions that are being considered might seem appealing from Duke's perspective, but they are clearly not appealing from the perspective of a small power producer, and would not be in the public interest.

148 Snider Direct, p. 25.

I am particularly troubled by the suggestion that Duke might start declaring a system "emergency" when solar energy is displacing some of Duke's less flexible generating resources, because those facilities do not have enough ramping flexibility. As testified by witness Holeman:

> [U]nder FERC's PURPA regulations, absent contractual agreement otherwise, a QF injecting energy into a system under a contract may be curtailed and the energy injections discontinued only in a "system emergency.". . . . The Companies' recent and growing experience indicates that solar QF energy is injected into the BA whenever the sun shines, and therefore, the BA operator has limited tools to maintain reliability in the face of these unscheduled and unconstrained injections of QF energy.[149]

If I understand this testimony correctly, Witness Holeman seems to suggest that whenever the sun is shining and the system load happens to be low, Duke should have the option to simply declare an emergency and stop paying QFs for their energy. I am confident that if the shoe were on the other foot, Duke would strongly object to this sort of one-sided solution to problem has many intertwined causes.

This proposal would not be in the public interest, and should not be adopted. First, it forces the solar power producers to shoulder entirely too much risk, since there is no limitation specified on how often the "emergency" can be declared, or how much revenue a QF will lose. This "solution" would effectively give Duke too much power to decide how much revenue a solar

149 Holeman Direct, p. 11.

QF can receive during any particular day or month, simply by declaring an emergency. Needless to say, this uncertainty would make it much more difficult to finance solar projects.

Second, it would be fundamentally anti-competitive to give this sort of discretion to the incumbent utility, since it competes with QFs as a builder and operator of generating facilities.

Third, this proposed solution creates the impression that the problem is being caused by the solar firms, which is simply not true. In reality, the operational challenges he is discussing are the result of multiple factors interacting with each other. Growth in solar, and the variability of this generating source are two contributing factors, but an equally important factor is the mix of generating technologies that happen to exist on Duke's system. If Duke had built fewer plants with long ramping times, and instead built more quick start combustion turbines and combined cycle plants, with their more rapid ramping and greater operational flexibility, these challenges would not be as serious, or simple solutions would be more readily at hand.

Q. ARE THERE ANY OTHER OPTIONS FOR OVERCOMING THESE CHALLENGES?

A. Yes. Although I am confident many options are worth investigating, I will not attempt to provide an exhaustive list. Instead, two simple examples will suffice. One option would be to modify how Duke's pumped storage capacity is managed. Perhaps more pumping should occur from mid-morning until noon, when solar energy is plentiful the potential for operationally "excess" energy is a risk. The water can then be used to send electricity back onto the grid later in the day, after the sun sets but air conditioners are still running. A second example would be to negotiate "Take or Pay" contracts with some of the solar QFs connected to its system.

Q. HAS DUKE ALREADY THOROUGHLY STUDIED THE PUMPED STORAGE OPTION AND REJECTED IT?

A. No, not to my knowledge. In discovery, Duke was specifically asked about the first option, and it did not appear to have rejected it.

> Request:
>
> Has non-utility owned renewable generation caused the Company to modify its operations of its pumped storage hydroelectric facilities? If so, please provide a narrative on the changes in operation of the pumped storage facilities,

> including changes in scheduling of recharge or discharge of power.
>
> Response:
>
> The 2016 IRP did not evaluate this issue. This assessment would require running two production cost runs, one with non-utility owned solar and another without non-utility owned solar to then analyze the effect on pump storage operations. No such analysis was conducted in the IRP scenarios.[150]

Q. WHAT ARE TAKE OR PAY CONTRACTS?

A. The accounting firm Ernst and Young offers an excellent brief definition:

> A take-or-pay contract is a supply agreement between a customer and a supplier in which the price is set for a specified minimum quantity of a particular good or service and the price is payable irrespective of whether the good or service is taken by the customer. Take-or-pay contracts are commonly used in the [Power and Utility] industry and may involve the supply of gas, transmission capacity or electricity. These contracts can be long-term in nature and contain terms and conditions with varying degrees of complexity (e.g., fixed or stepped volumes; simple fixed, stepped or variable pricing)[151]

"Take or Pay" is a pricing concept that has a long history in the natural gas industry (e.g. interstate pipelines and LNG suppliers), but it has also occasionally been used by electric utilities.

150 DEC response to NCSEADR 11-4, Docket No. E-100, Sub 147; see also DEC response to PSDR3-6, Docket No. E-100, Sub 148.

151 Ernst and Young, "The revised revenue recognition proposal – power and utilities," March 2012, p. 16, available at: http://www.ey.com/Publication/vwLUAssets/Power-Utilities_revised_revenue_recognition_proposal/$FILE/Applying%20IFRS%20Power-Utilities%20-%20Revised%20proposals%20for%20revenue.pdf (last accessed March 27, 2017).

A take-or-pay contract is typically used to resolve a dilemma which would otherwise arise, because there is a mismatch between the seller's need for revenue predictability and the buyer's need for operational flexibility. On the one hand, the seller might need a high level of assured revenue to justify making a large specialized investment that has high fixed costs (e.g., a Liquified Natural Gas terminal). On the other hand, the buyer might need maximum flexibility to decide whether, and to what extent it actually uses the service provided by the seller.

Consider, for example, a buyer that wants complete flexibility to decide whether, and when, to use an LNG terminal. The buyer is given the flexibility to use the terminal whenever they have a ship available for importing or exporting gas, but the owner and operator of the terminal is promised the assured revenue stream it needs to finance the project and cover its fixed costs, even if the terminal is sitting idle most of the time.

Q. WHY MIGHT TAKE OR PAY CONTRACTS BE HELPFUL TO DUKE?

A. In the solar context, a take or pay structure can provide a "win-win" solution which gives both the utility and the solar producer what they want. The contract can reassure the solar producer it will be paid for its output even if it is not taken, while Duke can be given complete operational control over the output, to keep or throw away, as it sees fit.

A Take or Pay contract can be structured many different ways, but in a typical case, if the buyer decides not to "take" all of the service that is offered by the seller, the buyer is committed to nevertheless "pay" for the offered service. The idea is to guarantee a minimum revenue stream to the seller, making it easier to finance a project, or to shift specified risks from the seller to the buyer. In general, the idea is to ensure that adequate financial compensation is provided to the seller, regardless of whether or not the buyer actually uses the full volume of service that is provided by the seller.

Q. COULD DUKE BENEFIT FROM PAYING FOR SOLAR ENERGY IT DOES NOT TAKE?

A. Yes, although this possibility is not intuitively obvious, since solar has virtually no variable expenses. Thus, from the perspective of a simple fixed and variable cost analysis, one would expect the solar plant would always be placed at the very bottom of the dispatch stack, even before nuclear plants, which use uranium and incur other variable costs. In practice, of course, the picture isn't quite that simple, since there are operational challenges involved with nuclear plants which may make them less flexible than solar.

There is the potential to extract some valuable operational benefits from solar facilities, if some of the solar energy is effectively discarded rather than used. In essence, some of the capacity is held back in reserve, to be instantly ramped up and sent to the grid on a second by second basis, as and when desired. If energy injections from some solar facilities were finely controlled in this manner, they could be used to help maintain stable voltage or function like spinning reserve (but only during times when the sun is shining, of course).

Q. FINALLY, CAN YOU PLEASE COMMENT ON THE PROPOSAL TO REDUCE THE 5 MW CEILING FOR THE STANDARD OFFER TARIFF TO 1 MW?

A. I do not think it would be wise to accept this proposal – it is simply too extreme a change, with too little thought having been given to the potential for unintended consequences. Admittedly, this particular proposal is not as troubling to me as some of the other proposals, like forcing fixed cost solar facilities to rely on an unpredictable revenue stream. And, there are obviously some tradeoffs involved with this issue. I can see some potential benefit from encouraging the industry to build smaller plants, which can be more easily located in urban areas, and more of the potential benefits from distributed generation can be achieved.

Cutting the other way, however, is the risk of unintended adverse consequence from such a drastic change. The main concern I have is that many firms may be very reluctant to engage in costly, time consuming negotiations, which may force them to stay within the familiar terrain of the standard offer tariff. If this happens, we may suddenly see a five-fold increase in the number of projects moving through the queues. This will impose very significant and unnecessary costs on the Utilities and the QFs, because of all the added paper work, engineering studies, legal documentation and other unnecessary expense in response to this proposal.

For that reason, I think, on balance, it would be unwise to change the threshold so drastically. If the Commission is inclined to modify the threshold, I would recommend making a much smaller step in that direction – perhaps to 3.75 or 4 MW. This would allow the Commission to observe how the market reacts to a change in the threshold. Perhaps firms will want to continue to build and operate 5 MW plants, because this is a familiar size. Or perhaps some will decide that as long as they are going to be forced to expend the time and effort required for negotiations, they will get a better return on that investment by building fewer, larger projects. In that case, we may see a surge in 10 or 15 MW projects. Either way, taking a much smaller step toward lowering the threshold would be prudent, rather than drastically changing it from 5 MW to 1 MW. Needless to say, whatever decision the Commission makes, this is something that could be reconsidered in the next biennial proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

4822-3197-1653, v. 6

BY MS. MITCHELL:

Q Dr. Johnson, did you prepare a summary of your testimony?

A Yes, I did.

Q Would you please provide it at this time?

A Yes.

(WHEREUPON, the summary of **BEN JOHNSON** is copied into the record.)

Before the North Carolina Utilities Commission
Docket No. E-100, Sub 148
Ben Johnson On Behalf of NCSEA
Summary of Testimony

My name is Ben Johnson. I am a Consulting Economist and President of a firm that specializes in public utility regulation. I am testifying in this proceeding on behalf of the North Carolina Sustainable Energy Association ("NCSEA"). I graduated with honors from the University of South Florida with a Bachelor of Arts in Economics in 1974. I earned a Master of Science in Economics in 1977 and a Ph.D. in Economics in 1982 from Florida State University.

I have been involved in public utility regulation since 1974, and have analyzed a wide range of issues involving many types of regulated firms. Over the past four decades I participated in more than 400 regulatory dockets, and provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia. The first time I recall testifying before this Commission was in 1983, in a Southern Bell rate case. Since that time, my firm has participated in more than a dozen proceedings before this Commission, most of the time on behalf of the Public Staff.

My firm has been retained by NCSEA to evaluate the concerns expressed by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") and Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") regarding the Commission's long-standing approach to implementing the Public Utility Regulatory Policies Act of 1978 ("PURPA"). In addition, I have reviewed the Utilities' proposed changes to the peaker methodology and input parameters and assumptions used in developing the new rates to be paid to Qualifying Facilities ("QFs").

My testimony is organized into seven sections which I will briefly summarize.

<u>Section 1: Implementation of PURPA in North Carolina</u>

Starting at page 9, I discuss implementation of PURPA in North Carolina, as compared with other states.

Since the Energy Crisis of the mid-1970s, many steps have been taken at both the state and federal level to reduce reliance on traditional energy sources and encourage greater energy independence and diversity. While many different tools have been used, including tax policies and incentives, some of the earliest steps were taken by the United States Congress in 1978 when it adopted PURPA. From my perspective as an economist, PURPA advances two goals: first, it encourages use of targeted technologies and energy sources which had been neglected by the electric utility industry; and second, it encourages investment in small power producers that are encouraged to enter the market to develop these targeted technologies and energy sources.

By requiring utilities to purchase the electrical output from these qualifying facilities or QFs, Congress not only pursued greater diversity of energy sources but it also encouraged narrowly targeted competition in electric power generation. PURPA was adopted at a time when policy makers were trying to encourage competition in industries, like the airlines and electric utilities, where it had previously been suppressed.

PURPA establishes a program of cooperative federalism, with state commissions playing an important role, implementing regulations established by the Federal Energy Regulatory Commission (the "FERC"). It is my observation that for more than 30 years, this Commission and the Public Staff have invested a high level of effort in analyzing the issues involved with PURPA, endeavoring to strike an appropriate balance that encourages QF development and protects retail ratepayers. These efforts are evidenced by the long series of actively litigated biennial avoided cost proceedings where the Utilities' proposals were subjected to a high degree of scrutiny by the Public Staff and other interested parties.

This long history of litigated proceedings distinguishes North Carolina from other states. In states with QF tariffs that do not offer certain critical elements (like long term contracts with fixed rates and reasonable terms and conditions), potential entrants may be reluctant to invest the time and effort required to litigate, since the outcome their investment is so unpredictable.

In response to discovery, Duke provided valuable information concerning implementation of PURPA in some nearby states – and in most cases the differences are stark. For instance, Alabama, Arkansas, Florida, Kentucky, Louisiana Maryland, and Virginia offer variable, rather than fixed, rates. This difference from North Carolina is critical, since variable rates present a major barrier to financing. Similarly, QFs are forced to negotiate rates, terms and conditions in Alabama, Georgia, Maryland, Mississippi, and West Virginia, as the standard offer tariff is only available to QFs 100 kW and smaller. In fact, aside from Tennessee, the only state cited by Duke which offers fixed long-term rates to QFs larger than 100 kW is

South Carolina – where Duke's QF tariffs are largely identical to those approved by this Commission.

Section 2: Growth of Solar Generation in North Carolina

Starting at page 33 I discuss recent growth in solar production and related concerns that have been identified by the Utilities. Duke witness Yates testifies that Duke Energy Corporation has invested $5.8 billion in renewable energy generation since 2007, including $300 million by DEP and $175 million by DEC in North Carolina. He doesn't emphasize that renewable energy remains a very small share of total electrical production. Duke Energy reported that its hydroelectric and solar generation combined provided just 0.7% of its total generation during 2016 – and this was actually down from the 0.8% which was achieved in 2015 and 0.8% in 2014.

As the Utilities point out, the growth in solar generation in North Carolina has been more substantial and more rapid than in nearby states like Alabama, Florida, Indiana, Kentucky, Louisiana, Mississippi, and Virginia. However, solar generating capacity still plays a minor role in DEC and DEP's generating portfolios whether measured in terms of energy or capacity.

The summer nameplate capacity of non-solar generating units in North Carolina totaled 20,270 MW for DEC and 12,873 for DEP as of March 30, 2016, for a combined total of 33,247 MW. The nameplate capacity is even higher during the winter months, due to cooler temperatures. About half of this capacity relies on fossil fuels (coal and natural gas), while approximately 30% is nuclear. Approximately 10% is hydro (including pumped storage units, which require energy from other fuel sources in order to function). In its 2016 IRP, DEC estimated it will have 735 MW of solar nameplate capacity connected to its system in 2017, growing to 2,168 MW in 2031 including QF capacity. Similarly, DEP estimated it would have 1,710 MW of solar nameplate capacity connected to its system in 2017, growing to 3,270 MW in 2031. For perspective, this is equivalent to roughly 3% of total capacity in 2017. and 6% in 2031.

The focus of the Utilities in this proceeding has been mostly on the challenges they face or may face as a result of more third party solar energy. They've given relatively little attention to the corresponding benefits, including increased geographic and fuel diversity, and reduced exposure to unpredictable, widely fluctuating fuel prices. Nor have they said much about how their QF tariffs could be improved to ameliorate the challenges they face by sending better, more precise price signals, or to increase the benefits to society by encouraging QF investment where it will be most beneficial, or to minimize risks and maximize benefits for ratepayers over the long run.

Section 3: Comparison of 2016 Rates to 2014 Rates

Starting at page 50, I compare the 2014 QF rate schedules, which provide 5-, 10-, and 15-year options, with the Utilities current proposals, which eliminate the 15-year option. I also discuss DEC and DEP's proposal to reset energy rates every two years, instead of keeping them fixed over the term of the contract. If approved, these two changes will greatly discourage QF investment. Furthermore, my analysis indicates a solar QF will receive 34.4% less revenue from DEC and 39.2% less revenue from DEP compared to the 2014 rates.

As has been the case for many years, the Utilities calculated the avoided cost rates using the Peaker Method. According to the theory underlying the Peaker Method, the capital cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system should produce the utility's full avoided cost of building and operating a new baseload generating plant, assuming the utility is operating at equilibrium. By combining higher energy costs with lower capital costs, the results of the Peaker Method are supposed to be equivalent to the results of using the Proxy Unit method to estimate the full avoided cost of building and operating a new baseload unit.

More specifically, the Peaker Method assumes that a utility's marginal fuel costs will be higher than its average fuel costs, and this difference will be sufficient to compensate for the higher cost of a baseload generating unit compared to lower cost peaker capacity. However, the fuel cost and dispatch data I reviewed for DEC and DEP suggests the Peaker Method is providing low-end estimates of avoided costs, given the percentage of time that coal-fired facilities, and not CTs, are operating at the "top of the stack" and since marginal fuel costs are quite close to the system average fossil fuel costs. Consequently, there is reason to doubt whether the marginal energy costs are high enough to be fully consistent with the theory underlying the Peaker Method. In other words, I am not confident that the avoided energy model output, when combined with the capital cost of a combustion turbine, will equal the full cost of a new baseload plant – as it should be.

To explore this concern in more detail, I developed long-run avoided cost estimates for a CT and for a Combined Cycle of CC unit. I found that the difference between the fixed cost of a CC and the fixed cost of a CT is approximately one cent per kWh. The underlying assumption of the Peaker Method is that marginal energy costs will exceed average fuel costs by an amount sufficient to recover this additional penny. However, marginal fuel costs have been closer to average fuel costs in recent years, so it is doubtful this intended result is actually being achieved. This is one of several factors I considered in concluding that ratepayers are not over-paying for QF power under the existing rates.

For this reason and others, I strongly disagree with the Utilities' claim that ratepayers are overpaying for QF output. Among other problems, this claim is based on a highly misleading short-term snapshot of fuel costs, it ignores the risk of much higher fuel costs in the future, and it doesn't make a fair comparison between the "All-in" price paid for power obtained from QF's with the actual long run cost of power provided by the Utilities, which includes capital-related costs and fixed operating and maintenance costs that were not included in the Utilities' comparison.

Section 4: The Indifference Standard

Starting at page 95, I discuss the "indifference" standard under PURPA, the concept of avoided costs, and the three standard methods for estimating avoided costs.

As the FERC has stated on several occasions, the intention of Congress in enacting PURPA "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA. This Commission recently confirmed, "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."

To test for this indifference, I developed cost estimates for several types of generating plants – nuclear, CC and CT. I concluded the long-run costs of constructing and rate basing these types of generating units has been in the same general range as what ratepayers have been paying for QF power, and that implementation of PURPA in North Carolina has been reasonably consistent with the indifference standard.

<u>Section 5: Avoided Energy Rates</u>

Starting at page 130, I discuss the Utilities' fuel forecasts and proposed avoided energy rates. I explain why I disagree with Duke's proposal to exclusively use forward market data, and I recommend the Commission direct DEP and DEC to use as a blend of forward market data and fundamental data, consistent with what DNCP has done. I also recommend that the Commission use the March 2017 EIA forecast as a benchmark to judge the reasonableness of the Utilities' forecasts.

I also analyzed the DEC and DEP proposal to no longer offer fixed, long-term energy rates, which will force both QFs and ratepayers to bear additional risks associated with variable energy rates. Having identified a perceived problem with QF rates that were fixed, while fuel costs unexpectedly declined, DEC and DEP propose to "fix" this perceived problem by changing the QF tariff to eliminate fixed energy rates. This is an extreme response, which fundamentally changes the economics QF development.

Under the current structure, a QF benefits from a fixed revenue stream that aligns well with most QF investments, with their high fixed costs and low variable costs. DEC and DEP propose to replace a stable, predictable revenue stream that is closely aligned with underlying economics of QF technology, with a highly unpredictable revenue stream that is poorly aligned with the underlying economics. Not only will the future revenue stream be unnecessarily linked to the future course of volatile fuel prices, it will fluctuate with variables that are fundamentally unknowable and unpredictable from the perspective of the QF and their financiers, further increasing risks and discouraging investment.

This change does not benefit ratepayers at all. In fact, this change eliminates one of the most attractive features of QF power from the perspective of the customer. In general, solar and hydro production offer valuable diversification benefits because they are impervious to fuel price risk. Hence, from a purely economic perspective, the more solar and hydro generation that is introduced into the portfolio, the lower the fuel price risk to customers. The benefits of this cost stability and risk reduction would be largely eliminated by DEC and DEP's proposal.

Finally, I analyzed DNCP's proposal to reduce its energy rates based on the historical energy price differences between the DOM Zone and its North Carolina service area. Conceptually, I have no objection to using LMP data to help refine the QF rates, as LMPs may be relevant to the problem of how best to improve QF price signals, in order to encourage QF power to be generated where it is most valuable. However, additional granularity and further refinement is likely appropriate, and I identified nine closely related issues that should be investigated by the Commission before deciding whether to adopt some variation of this proposal.

Section 6: Avoided Capacity Rates

Starting at page 179, I discuss two aspects of the Utilities' proposals that are essentially the same as ones that have been proposed and rejected in the past – the use of zeros in calculating the avoided capacity rates, and reducing the Performance Adjustment Factor ("PAF") from 1.20 to 1.05.

The proposal by DEC and DEP to use zeros has the effect of reducing the avoided capacity rate by 65% for DEC and 56% for DEP. DNCP's proposal would eliminate the avoided capacity rate entirely. The Commission rejected the DEC and DEP proposal in the 2014 biennial avoided cost proceeding outright, concluding this is inconsistent with the Peaker Method and with FERC precedent. I agree with that decision and I would urge the Commission to reach the same conclusion in this proceeding.

I also provide some additional reasons to reject this proposal. In particular, since utilities add capacity in large additions, it is clear from economic theory that long run capacity costs are present in every year; they are not zero in some years. Investment "lumpiness" results in zero physical need for new capacity in most years, but reserve margins vary from year to year, and older plants slowly becoming costlier to maintain and operate as they gradually near retirement. Given these circumstances, the long run cost of capacity is the same, or nearly the same, during the years when no capacity is added as it is during the years when a large new block of capacity is scheduled for commercial operation.

As they have in the past, DEC and DEP once again propose to reduce the PAF to 1.05, based on the availability of a CT. The Commission most recently addressed this proposal in 2014, when it made clear that the availability of a CT is <u>not</u> determinative for purposes of calculating the PAF. The Commission appropriately focused on the fact that the avoided cost to be calculated is the cost of any generating unit, not simply a peaking unit. Thus, it is more appropriate to focus on availability data for all generating units, not just a CT.

<u>Section 7: Rate Design</u>

Finally, starting at page 192, I discuss the Utilities' proposals concerning seasonality and hourly cost variations. In general, the Utilities do not propose any improvements to the definitions of on-peak and off-peak hours, which is surprising given most of the problems they describe are time-related. Additionally, DEC and DEP propose to change the seasonal allocation of capacity costs, without improving the way they define the non-summer season. I recommend that the Commission reject that proposal, which is not an improvement and is entirely inconsistent with data showing when peak loads actually occur. Instead, the Commission should initiate steps to provide stronger, more precise peak and off-peak signals.

4819-1273-7094, v. 2

MS. MITCHELL: Chairman Finley, the witness is available.

CHAIRMAN FINLEY: Do intervenors have any cross examination of Dr. Johnson?

MR. DODGE: I have just a couple.

CROSS EXAMINATION

BY MR. DODGE:

Q Good afternoon, Mr. Johnson. Tim Dodge with the Public Staff.

A Good afternoon.

Q I just have a couple of brief questions. On page 120 of your testimony, do you mind turning to that page?

A Okay.

Q And on the lower half of that page you discuss a recent experience in South Carolina where they evaluate, SCE&G evaluated the economic viability of its V.C. Summer nuclear construction project.

A Yes.

Q You describe their analysis of different scenarios and potential gas prices. And I just want to note on the bottom of that page carrying over to the top of page 121, you quoted from that analysis starting on line 20, *To develop this* *forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years and then applies an escalation factor ... to forecast prices beyond three years in the future.*

A Yes.

Q Did you work on that economic analysis for SCE&G?

A No, I reviewed it.

Q Have you worked on avoided cost proceedings in South Carolina?

A Yes.

Q Do you know -- are you familiar with how -- have you worked on SCE&G's avoided cost proceedings?

A Yes.

Q And are you familiar with how they use gas prices -- the forecast they use for gas prices in their avoided costs?

A Yes. It's similar to what's described here. They start with market data for a couple of years and then they start escalating it using an escalation factor that they believe is consistent with what they think the future will bring, and very similar to this idea of a fundamental forecast although they don't label it that way.

Q And have you worked on other avoided cost
proceedings in the southeast for any other
utility?
A Not recently.
Q Do you think there's -- is there a relationship
between the Utilities use of how it utilizes
forwards and fundamental forecasts for avoided
costs or IRP planning and the Utilities' actual
fuel procurement practices?
A Well, I certainly don't claim to be an expert on
exactly what every utility is doing in every
state, but I think my testimony fairly conveys
the general situation as I understand it. First,
in some states they're using variable rates so
the question of forecasting is not much of an
issue nor is there much QF power. You don't see
much solar development because of -- the
situation is so risky for the QF developer. In
terms of like IRP process, I think it's pretty
typical for the Utilities to be using fundamental
forecasts after the first few years. I think
that is -- the DNCP practice in my impression is
probably more typical of what's happening than
what Duke has recently been doing here in North

Carolina. I had some testimony about, quoting testimony I found online from Duke Florida that suggests that more emphasis is used on fundamental forecasts in Florida as well. Again, I am not claiming to be an expert on each utility throughout the country but I think in general fundamental forecasts continue to be widely relied upon for long-term purposes.

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

CHAIRMAN FINLEY: Companies?

MS. FENTRESS: No questions.

MS. KELLS: No.

CHAIRMAN FINLEY: Redirect?

MS. MITCHELL: No, sir.

CHAIRMAN FINLEY: Commission questions of Dr. Johnson?

EXAMINATION

BY COMMISSIONER BROWN-BLAND:

Q Just one, Dr. Johnson, I forgot to ask Dr. Vitolo. So I think both of you have cited Duke's past justification for the 1.05 PAF as tied to and based to replacement of a CT.

A Uh-huh.

Q And if I correctly understood Mr. Snider's discussion with me yesterday, he's saying that view has changed or that underlying rationale has changed, that they're now looking across their baseload fleet at least, if not more, but still coming to the 1.05 PAF. Do you have any -- if you disagree with my understanding of what he said say so. But if -- well, one, do you have a different understanding and, two, what do you say about that 1.05, if it's true that this number is now a result of looking across this system?

A I think the impression you had is probably pretty close to what was stated. But if you go back and look at the discovery responses in the original testimony I think a little more light can be shined on it. It is clear to me that as filed they were relying on the same arguments and the same CT rationale that they used historically. Perhaps in response to the Public Staff's shift in stance, they are now suggesting that consideration of baseload units would be reasonable, and what they're suggesting, however, is that that focus on baseload units should be limited to certain hours, which I understand to be what they're calling on-peak hours. From my perspective, that is finally some movement towards a more rationale and fact-based basis for discussing what is the optimal PAF. It seems clear that under the peaker method you really have to be looking at baseload data. You can't be simply limiting it to peaker and that has been a mistake all along on their viewpoint because it's sort of mixing and matching elements of the peaker method with other things because the peaker method is designed to cover energy production from baseload units. And I don't necessarily object to this idea that we need to focus on when that availability is most important.

There's two concerns I have or quibbles that I think are kind of serious. One is sort of the late stage in which they suddenly decided they wanted to focus on that which hasn't really given us an opportunity to sort of work it out with them and discuss and look at in detail how they're calculating it. And, more importantly, the second one is I'm concerned about their continued insistence on using arbitrary, overly broad, on-peak time periods. I understand that was agreed to in a settlement some years ago, this Option A/Option B, but if we're going to try to refine the calculations and really make sure we're doing it right as long as we're going to change it, it seems to me we need to be weighting different hours differently. We've heard testimony and it's very clear and I think I've provided very, very convincing evidence that the most important time to have capacity is in the late afternoon in the summer, that's when the great majority of the extreme peaks occur, but times before and after that are also important. And similarly the other important time is early mornings in December, January and February. And the problem I have is that they're defining peaks very differently than that. They're doing things like 6:00 a.m. to 1:00 p.m. through a very broad time period from October to May. And contrary to some of the testimony we heard, if you look at their nuclear performance at the other units, those are taken offline during what are defined as on-peak periods in the tariff but which I would certainly agree with Duke are not truly the on-peak periods. In other words, they are very careful about taking those units offline during the spring and the fall, and the same holds true with some portion of their scheduled maintenance on the coal units, they tend to schedule them. Once they schedule it for maintenance, take a unit down, and replace parts, do the things they have to do, it tends to be offline during the on-peak hours as well, but it's during times of the month when it's of less concern so what I'm suggesting is the end result of all of this. I don't know what the final number would be but it troubles me that we're talking about changing one little piece of the traditional process without doing sort of the roll up our sleeves and do the calculations in detail the way they really ought to be done. Whether that final number will be closer to 1.05 or closer to 1.15, I don't know. But again, I think as a matter of good regulatory practice, it would be better to turn it back to the parties and say we're willing to look at this again, we want to see better evidence in the next proceeding or in whatever process you want, a collaborative process with Public Staff and other parties. There's many ways you can do this but I don't think it's time to just arbitrarily change from the 1.20 to the 1.05, which was based on a CT, based on some offhand comments on the stand about well there's another way you could look at it. Again, if we're going to look at availability of baseload units, we really ought to look at it in a sophisticated manner.

Q So there is this split from summertime and non-summer. But if you're looking over the whole year, all the way throughout the year there are peak -- there are peak hours all through the year, right?

A Yes. And the degree of importance of those peaks varies. The most important ones are in the summer afternoons. The next most important are in the early mornings of December, January and February. The less important ones are incurring during the other months. And similarly there's further granularity that also occurs in terms of weekends and so on. Again, the thing that's troubling for me is, you know, other parties have suggested there's a need to be refining the on-peak and off-peak signals, that we're not really sending the right price signals to QFs. The case of solar -- there's not quite as much opportunity for response as for some other technologies, but even with solar you can put in tracking, you can put in fixed, you can choose your tracking mechanisms in response to the tariff. And when they stick with a time of day price structure that's from years ago that is not precise, it inherently makes it harder to allow the QF industry to respond and help solve some of the operational problems Mr. Holeman's talked about. And some of the other concerns that I can see coming down the pipe where, for example, during the noon hour on a weekday you're going to have a maximum amount of solar capacity and a maximum amount of energy coming out but arguably the power during that particular hour isn't as valuable as some other hours. Why aren't we sending a good solid price signal to the QFs to reflect that fact? Why are we instead citing, in essence, pointing to the inexactness and the flaws in the current system as a reason to essentially shut down QF development and make it very, very difficult to finance and very difficult to invest? I just don't think it's the right response. To me the right response is let's improve the tariffs.

Q So going back to my summer, non-summer and peaks all through the years. So any time you take a unit off it's necessarily down during peak, during some peak hours, right?

A Absolutely. And if you take enough units off you sometimes have a problem meeting peak during those off-summer months.

COMMISSIONER BROWN-BLAND: Thank you.

EXAMINATION

BY COMMISSIONER BAILEY:

Q Good afternoon, Dr. Johnson.

A Good afternoon.

Q Can you hear me?

A Yes.

Q I guess I want to start off with the idea that - are you in agreement that North Carolina either has a duck curve right now or very well is approaching a duck curve in the next two years as a result of the solar and the amount of access solar, particularly in the DEP area in the eastern part of the state?

A My impression is there are some hours when they are already having enough solar generation in the middle of the day that really ought to be modeled, and it's very disappointing they never modeled it. They have this model, ProSim or PROMOD, ProSim can readily start modeling hour-by-hour. They could have been presenting data of what the impact of that is. They could have modeled the effect, for example, the burden - I'm going to be honest with you - it's a burden of putting less coal units online and using more CTs, if you're anticipating a problem with excess generation in the middle of the day because they have better ramping. There's so many things they could have modeled and could have shown the parties to allow us -- the peaker method is not, you know, it's fully capable of answering a lot of these questions but we're using models that we don't have access to that they use and they chose not to run them. So I'm not denying that during some hours of some days there was already a concern about extra energy, energy that is not as valuable as we would like it to be, but I'm certainly not at a -- don't think the facts are at a point where the problem is so pervasive the solution is to just put the brakes on and stop QF development.

Q Okay. So you're in a -- so you're saying that a possibility is that some type of duck curve is existing in the eastern part the state and as it goes forward with another 1000, 1100, 1200 megawatts of solar to be done in the next year or so, that at some point in time they're going to have an issue where they've got to stop -- they've got to start dumping some of this excess load because their loads in DEP certainly is not going to absorb that. And, if they can't transport it, somewhere else in their own -- into the dispatch -- Joint Dispatch Agreement they're going to have to do something with this excess energy. Is that a correct assumption or do you disagree with that?

A That's -- I know my answer seemed like it was not fully responsive but it actually was. I was trying to capture a lot of thoughts in my previous answer. No, I don't think the problem is so extreme yet that we have to be treating it as a major problem with dumping energy. To the extent they're dumping energy, that is at least in part because they haven't yet had the time to work through the better ways to optimize the system in the face of significant solar production. The problem, if you want to call it a problem, or the issue of high levels of solar production at which will grow over time is going to be most noticeable during, let's use a simple example, a weekend during the day at noon because you don't have a tremendous amount of load but the sun is still shining. The optimal solution -- there are so many tools in their toolkit that they have not yet fully explored. Of course, there's the question of pump storage and re-optimizing their whole strategy for how they use the pump storage. There's a lot of pump storage. At least on the DEC system it makes a difference. But there's also the question of which units you plan for the day. And, if you know you're going to have a lot of solar coming online, you need to rethink the question of what's the optimal mix of units. And that optimal mix of units might have more CTs and less coal units because the coal units are the slowest ramping and the most difficult to deal with. You may be able to sell the power and plan in advance and sell the power 24 hours in advance to another utility and arrange the necessary transmission lines. There's many options open to them that they have not fully explored and that's my concern. It's not that -- with growing amounts of solar, we're going to see this throughout the country, there will be needs to adjust operating practices. And I believe on net balance society is better off, on net balance ratepayers are going to be saving money, but the precise calculations we don't know yet because we haven't been modeling it the way we need to be.

Q Okay. I guess maybe what I glean from that answer, Dr. Johnson, was the fact that really Duke or the Utilities' responsibility to pretty much forecast next-day requirements knowing, based on the weather patterns, that it's going to be a clear day and the sun is going to be shining and you can expect to have 11, 12, 2000 megawatts of solar on your systems during that period of time when the sun obviously is going to be shining. And it's your responsibility to pretty much plan what you're going to have as far as other generation on that system to take advantage of that 2000 or whatever megawatt solar that you've got being generated; is that --

A In practical terms it is their responsibility. They are the ones who are making the operating decisions and have the expertise to do that on a day-to-day basis. I don't question that at all. I don't want my answer to be taken out of context and appear as though I'm saying the solar industry isn't prepared to help with discussing optimal strategies and discussing how the rates ought to adapt to those strategies and how price signals could be sent to the solar facilities to enable them to help with the problem as well, if there is a problem. But in general terms, just a perspective, you said a couple of thousand megawatts of solar and it depends a little bit on whether we're talking about nameplate or net. The net is what really matters for this purpose because that's how much energy is going to get sent out. But even if we're talking a couple of thousand megawatts of net energy production which is quite a number of years out, that's still very small compared to the 20,000 to 30,000 megawatts of capacity this Company has. So it's not like we're dealing with -- overnight we're going to have a problem with 10, 20 percent of the energy flowing in in a way that they're not used to seeing, which they are not directly controlling; they have to basically predict it and model it unless they want to control it, if they want to control it. I talked about that in my testimony. But assuming they don't want to control it, they simply want to predict it, they simply need to -- as step one they need to start modeling the problem in more detail; step two, they need better information. They need real-time meters on every one of these QFs sending data back minute-by-minute that they can then model in the computer to understand weather forecasts and what the correlation is between actual weather conditions, weather forecasts and the actual output of each one of these generators. Once they have that, they're going to start treating it as a routine part of the way they do business in a way they're not yet able to do and are not yet at the state of doing. Once they have that expertise, I honestly think they're going to be at the front edge of the whole country because I think throughout the country and through the world solar is becoming more and more cost-effective. People are going to want to learn from them and learn how best to deal with it.

Q So you're in agreement that Duke's request to be able to curtail some of their QFs is a reasonable request or do you think that's not?

A I think as one of the toolkits to be curtailing it on a contractual basis where they have control and can dispatch the solar, but they contract with the QF to give them that right and compensate the QF so it's not harming the QF could be one of their toolkits. And in so doing they will actually get benefits they don't currently have that solar actually is, when it's controlled like that, can actually be useful for spinning reserve and other purposes. But I'm not suggesting that is the primary thing they'd want to do because my intuition as a economist is you don't want to throw away energy that has no variable cost. For the same reason you wait til the end before you start bringing down your nuclear units. Because they only have a penny or so of fuel, you don't want to be bringing solar down at a zero cost of variable cost as a routine matter. But, again, on a selective basis, controlling it for a limited number of hours of the year might very well be part of the package that they ultimately come up with as optimal.

COMMISSIONER BAILEY: Thank you. I appreciate that.

CHAIRMAN FINLEY: Questions on the Commission questions?

(No response.)

Let's take a -- thank you, Dr. Johnson.

THE WITNESS: Thank you.

CHAIRMAN FINLEY: You may be excused.

(The witness is excused.)

Let's take a 15 minute recess.

(Recess at 3:45 p.m., until 4:00 p.m.)

CHAIRMAN FINLEY: Let's go back on the record. I apologize for the temperature in the room. Anyone who wishes to take off their jacket or whatever you're welcome to try it.

(Laughter)

We are tenants in this building to the extent the landlord is engaged in some demand response program --

(Laughter)

CARSON HARKRADER; was duly sworn and testified as follows:

DIRECT EXAMINATION

BY MR. LEDFORD:

Q Thank you, Ms. Harkrader. Could you please state your name, employer and title for the record?
A Yes. My name is Carson Harkrader. I work for Carolina Solar Energy II, LLC. And what was the last one?
Q Title.
A Oh, I'm the Director of Project Development.
Q And what is your business address?
A It is 400 West Main Street, Suite 503 in Durham, North Carolina.
Q Thank you. And on whose behalf are you testifying in the proceeding?
A On behalf of the North Carolina Sustainable Energy Association.
Q And did you cause to be prefiled in this docket on March 28, 2017, direct testimony consisting of

25 pages?
A I did.
Q And do you have any corrections to make to your prefiled testimony?
A I do not.
Q And, if I were to ask you the same questions today, would you answer them the same as stated in your prefiled testimony?
A Yes, I would.

MR. LEDFORD: Thank you. Mr. Chairman, at this time I move that NCSEA Witness Harkrader's prefiled direct testimony be copied into the record as if delivered orally from the stand.

CHAIRMAN FINLEY: Ms. Harkrader's direct prefiled testimony of March 28, 2017, consisting of 25 pages is copied into the record as though given orally from the stand.

MR. LEDFORD: Thank you.

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

3C04

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016

DIRECT TESTIMONY

OF

CARSON HARKRADER

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

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OFFICIAL COPY

Mar 28 2017

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carson Harkrader. My business address is 400 West Main Street Suite 503, Durham, North Carolina, 27701.

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

A. I am the Director of Project Development for Carolina Solar Energy II, LLC (which I will refer to as "CSE"). CSE was founded by my father, Richard Harkrader, to develop utility scale photovoltaic solar energy projects in North Carolina. From 2004 until the end of 2012, CSE provided design, financing, construction and operation management to a diverse customer base of commercial, nonprofit, utility, and government clients. Beginning in 2012, CSE modified our business model to provide project development services to local, national, and international solar companies. CSE is a business member of the North Carolina Sustainable Energy Association, on behalf of which I am providing this testimony.

CSE has successfully developed approximately 200 megawatts ("MW") alternating current ("ac") of solar generating facilities, made up of 39 projects that are currently under construction or already operating in North Carolina. The first project our company built was at PNC Arena, on the North Carolina State University campus here in Raleigh. At 75 kilowatts, at the time it was turned on in January 2008, this was the largest privately owned grid-tied utility scale solar project in the Southeast. Other early CSE projects include installations at the North Carolina Zoo, on the roof at the City of Raleigh's E.M. Johnson Water Treatment Plant, and at the entrance to the Person County Industrial Park located on US Highway 501, where we often have sheep that graze around the solar panels. In 2012, we started developing 5 MWac sized solar projects, and in 2014 we began developing larger 50 MWac sized transmission interconnected solar projects, the first of which is now under construction in Vance County. So, our company has grown along with the industry here in North Carolina.

Q. PLEASE DISCUSS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Arts with Honors in Political Science from Brown University, and wrote my honors thesis in 1999 on the deregulation of the electric utilities in Rhode Island. I also earned a Master in Business Administration in Finance and Strategy from New York University. Prior to business school, I was employed for eight (8) years on the commercial sales team with GE Energy in Asia and New York. While at GE Energy, I led teams to sell wind and gas turbines in the United States, Canada, and Asia and was the lead negotiator on sales contracts for hundreds of megawatts of wind and gas turbine technology, managing the input of GE's engineering, sourcing, legal, and finance teams in the contract negotiation process. Prior to working for GE Energy, I spent two years at a renewable energy development company in Sydney, Australia, which developed biomass and wind energy projects and completed an initial public offering and listed on the Australian Stock Exchange in 2002. After completing business school, I returned home to North Carolina in 2012 to work with my father at CSE. At this point in time, I have a total of fourteen years' experience in the energy industry and am familiar with solar, wind, conventional gas turbine and steam turbine technologies, and project development.

I have been the Director of Project Development at CSE for four and one half years. In this role, I oversee the company's solar QF development process. As Director of Project Development, I have been involved in the development of nineteen 5 MW ac qualifying facilities ("QFs") that are in operation or under construction in North Carolina. Additionally, I have been involved in the development of four large QFs that have secured power purchase agreements with Duke Energy Progress, one of which has started construction and the rest of which are preparing for construction later this year or early next year.

CSE is an early stage developer, meaning that we complete the land acquisition process, local permitting, and environmental permitting along with certification at the North Carolina Utilities Commission (the "Commission") and at the FERC. We also initiate the interconnection process with the relevant utility. In addition to managing this process, I am responsible for working with other companies who partner with us to complete the financing and the construction of the solar farms. These relationships provide us with constant, ongoing feedback on the terms and conditions that are necessary for a project to secure financing and, ultimately, to be constructed.

In my years of working at CSE and developing solar facilities in North Carolina, I have had the opportunity to work closely with employees of Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP") (collectively, "Duke") and Dominion North Carolina Power ("Dominion") (Duke and Dominion collectively, the "Utilities"). It is my experience that the utility employees with whom I have worked have been very dedicated to their work and, in my opinion, have played a significant role in the success of the solar industry in North Carolina. CSE and NCSEA, as well as myself personally, are very appreciative of these efforts and we look forward to continuing to work together.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. I have not previously provided expert testimony to the Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to several of the proposals made by the Utilities related to the implementation of the Public Utility Regulatory

Policies Act ("PURPA"), to provide the Commission with my observations, based on my experience, as to how PURPA must be implemented if the Commission's objective is to encourage QF development while managing risk and value to ratepayers associated with QF development, and to discuss the implications of the changes proposed by the Utilities to the continued development of QFs in North Carolina.

Q. PLEASE IDENTIFY THE SPECIFIC PROPOSALS TO WHICH YOU ARE RESPONDING.

A. My testimony is offered in response to Duke's characterization of solar development in North Carolina as "uncoordinated and unconstrained" and "unmanageable,"[1] as well as several of Duke's concerns related to the output of solar generating facilities.[2] My testimony is also offered in response to: i) the Utilities' proposals to reduce eligibility for the Commission-approved standard rates and contract terms available to QFs (the "Standard Offer") to one (1) MW from five (5) MW;[3] ii) the Utilities' proposal to reduce the

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[1] Direct Testimony of Lloyd M. Yates on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Yates Direct"), p. 4, l. 23; p. 10, l. 10.

[2] Direct Testimony of John Samuel Holeman III on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Holeman Direct"), pp 10, l. 18 – p. 11, l. 18.

[3] Yates Direct, p. 11, ll 1-2; Direct Testimony of J. Scott Gaskill on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100. Sub 148, February 21, 2017 ("Gaskill Direct"), p. 14, ll 9-10.

maximum duration of the standard contract from 15 years to 10 years;[4] iii) Duke's proposal to offer a variable energy rate and not a fixed energy rate;[5] iv) Duke's proposal to transition to a competitive procurement process to support continued solar development in North Carolina;[6] and v) Duke's proposal to modify the standard for establishing a "legally enforceable obligation" ("LEO") by requiring a QF to progress through the System Impact Study process and commit to proceed to a detailed Facilities Study in the context of the interconnection process.[7]

Q. WHAT IS YOUR RESPONSE TO DUKE'S CHARACTERIZATION OF SOLAR DEVELOPMENT IN NORTH CAROLINA AS "UNCOORDINATED AND UNCONSTRAINED" AND "UNMANAGEABLE"?

A. I do not believe that this characterization accurately reflects the reality of developing a solar QF in North Carolina.

Regarding the characterization of solar development as "unconstrained," notwithstanding industry's past success in North Carolina,

[4] Yates Direct, p. 11, ll 3-4; Gaskill Direct, p. 15, ll 4-5.

[5] Yates Direct, p. 11, ll 4-7.

[6] Direct Testimony of Kendal C. Bowman on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Bowman Direct"), p. 61, ll 5-19.

[7] Direct Testimony of Gary Freeman on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Freeman Direct"), p. 14, ll 19-22.

the development of solar facilities is constrained by a number of factors and is becoming more constrained over time. At a high level, early stage development work includes the following steps: 1) identifying the site – we identify sites primarily based on the suitability of land (i.e., lack of wetlands, outside of the 100-year floodplain, reasonably flat, reasonably large tracts of land), as well as proximity to utility infrastructure suitable for interconnection; 2) making regulatory filings; 3) undertaking the local land use approval process; 4) performing environmental due diligence; and 5) making an appropriate interconnection application to the applicable utility, paying the deposit and application fees and participating in the interconnection process.

An increasing amount of time is required to identify appropriate sites in North Carolina for solar development, as suitable land close to utility infrastructure has become scarce over time. Additionally, a significant amount of time and resources are required and must be committed to secure the necessary local land use approvals. We engage extensively with neighbors and community leadership prior to filing applications for land use approvals. Once we initiate the approvals process, we appear before Planning Boards and Boards of Commissioners (or the equivalent), often in a quasi-judicial proceeding. In counties or towns that do not have a solar ordinance in place, we work with the planning department on the development of an appropriate ordinance to regulate the construction of solar farms in that community, using a best practice template ordinance that was developed through a state-wide stakeholder process. In my experience, the counties and communities that we work in have been interested in learning more about solar energy, particularly the economic development benefits and the local tax base that solar projects provide, as well as the solar generating technology. We enjoy being able to provide this information to those communities.

Regarding the characterization of solar development as "uncoordinated," both Duke and Dominion acknowledge that solar generating capacity can provide benefits when located at certain points on the grid;[8] however, this information is not shared with or made readily available to QF developers. Additionally, inverter technology, such as that used in the types of solar generating facilities being developed in North Carolina, is dispatchable to provide a variety of benefits to the grid, including: 1) enhancing the ability of the grid to ride through low voltage events to prevent a loss of power for other customers; 2) supplying reactive power, which could offset utility investments in their own supply of this power; and 3) other power quality services which can offset utility expenditures. However, the utilization of these capabilities in a manner that benefits the grid requires communication and integration, and, to date, we have not been provided the opportunity to work with the Utilities on this

[8] Yates Direct, p. 8, l. 15; Gaskill Direct, p. 17, l. 17 – p. 18, l. 15.

issue. Thus, to the extent that a QF can deliver greater value to the electric utility and its ratepayers by interconnecting at a specific location or by setting inverters to provide certain services to the grid, these opportunities are not encouraged or enabled by the Utilities, and are therefore lost.

Duke witness Holeman expresses concern regarding paying for "operationally excess" energy produced by solar QFs and the operational challenges of managing "unscheduled" and "unconstrained" solar QF energy injections onto the grid. However, other jurisdictions experiencing higher penetration of solar generating capacity than North Carolina are addressing these types of issues through various means, including thoughtful rate design and pricing approaches that involve, for example, time-of-day pricing. My understanding is that Option B offered to QFs under the Utilities' respective rate schedules was a step in the direction of better aligning the output of a solar QF with the peak needs of the Utilities, and I am aware that many solar QFs in North Carolina have been installed using a design that increases energy production during the peak rate times identified in the Option B rates and decreases energy production during non-peak rate times. A further refinement to this approach to address some of the Utilities' concerns should be evaluated and implemented, in the interest of maximizing the value that solar generation can provide to the utility and its ratepayers. NCSEA expert witness Ben Johnson discusses this concept in greater detail in his testimony.

Finally, the interconnection process continues to evolve, and in effect, limit the numbers of QFs that have been and will be developed in North Carolina. I was involved in the stakeholder discussions that took place in 2014 regarding the North Carolina Interconnection Procedures, Forms and Agreements for State Jurisdictional Interconnection Agreements (the "Interconnection Standard").[9] For almost a full year, I participated in the discussions, which related to improving the interconnection process in light of the increasing number of interconnection requests, the interactions and interdependencies among the increasing number of interconnection requests, the administrative burden to the Utilities, and the delays in processing and completing interconnection requests caused by "speculative" QF developers. The work of this stakeholder process resulted in significant revisions to the Interconnection Standard. However, in spite of the effort put into the stakeholder process, in my experience, the process of interconnecting a QF takes much longer now than prior to the revisions to the Interconnection Standard.

For example, in May 2012, an interconnection request was submitted for a 5 MWac solar QF that CSE developed in Wilson County. The interconnection request progressed through the study process over that summer, and the project received a fully executed an Interconnection

[9] See Order Approving Revised Interconnection Standard, N.C.U.C. Docket No. E-100, Sub 101, May 15, 2015.

Agreement from the utility by mid-November 2012. The QF was constructed and interconnected in July 2013. For this QF, the interconnection process took a total of 14 months from initial submittal of request, to interconnection to the grid. In contrast, for a similar 5 MWac solar QF located in Richmond County, CSE submitted the interconnection request in July 2015 (twenty months ago) and still has not received results from the System Impact Study process.[10] The Richmond County project has received local land use approvals and environmental permits, and is otherwise ready to move forward with financing and construction, but without the study results from the utility, cannot move forward. These two examples are typical of the change in interconnection timelines that industry has experienced.

It is my experience that the interconnection process for distribution connected QF projects is effectively on hold at this point in time, except for those interconnection requests that had already received their System Impact Study reports and Interconnection Agreements in early- to mid-2016. To provide more information on this, in 2016, CSE was involved in the interconnection of twelve (12) 5 MW ac solar QFs to the grid. CSE projects that in 2017, only four (4) 5 MW ac solar QFs will be interconnected. One interconnection request made by CSE in the summer of 2014 has still not

[10] The System Impact Study is one of the study processes set forth in the Interconnection Standard. The System Impact Study results identify and detail the electric system impacts that would result if the proposed generating facility were interconnected. Additionally, the System Impact Study results provide preliminary estimated charges for interconnection facilities and for upgrades to the utility's system. See Interconnection Standard, Section 4.3.

received results from the study process, and we have only received only one (1) new System Impact Study back from the utility for a distribution level QF in North Carolina in the past twelve (12) months.

Q. WHAT IS YOUR RESPONSE TO THE UTILITIES' PROPOSALS TO MODIFY THE WAYS IN WHICH PURPA IS IMPLEMENTED IN NORTH CAROLINA?

A. In general, I am very concerned that the Utilities' proposals to modify the ways in which PURPA has been implemented in North Carolina would have the effect of curtailing QF development in North Carolina.

As the Utilities have pointed out, over the past few years North Carolina has been an undisputed leader in terms of installed solar generating capacity. As Duke's witnesses have described in their testimony, approximately 1,600 MW of third-party solar was interconnected in the DEC and DEP service territories as of the end of last year, and as a Dominion witness describes in his testimony, approximately 350 MW of third-party solar is in commercial operation in its service territory. CSE has been one of the companies involved in this success, and we have worked hard to reduce costs and increase efficiencies with the objective of achieving cost-competitiveness with other generation technologies in North Carolina. We are also very proud to have played an important role in bringing over $3 billion in economic development to rural North Carolina.

I think all stakeholders agree that the Standard Offer has been a vital component of the success of solar development in North Carolina. Interpretations differ, however, about why the Standard Offer has led to this success in solar development. Duke characterizes the Standard Offer as "significantly more generous to solar developers than those offered by other utilities and states." However, in my experience, the biennial avoided cost rates in North Carolina have decreased over time since 2010. The "all in" 2014 avoided cost rates for the different Utilities range between five and a half (5.5) and seven and a half (7.5) cents per kilowatt hour, based on North Carolina solar generation profiles, and it has been industry's ability to drive down costs and create economies of scale that has allowed us to make the economics work to continue to develop QF projects in North Carolina even in spite of decreasing avoided costs and associated rates paid to QFs, expiring tax incentives, and very low to no value for renewable energy certificates.

Unique to North Carolina is that we are one of the few states that has ensured that certain critical policies, including long-term contracts and fixed pricing, are in place to encourage QF development. QF development has simply not occurred in those states that have not implemented these same critical policies. For example, CSE has explored development in states other than North Carolina and has found that in many states utilities do not offer long-term contracts or fixed pricing to QFs. In those states in which contract duration is short and rates are variable, as opposed to fixed, material QF development has not occurred.

In my experience, the 15-year contract, coupled with the fixed rate over the entire contract term, are critical to enabling a QF to attract capital. Although NCSEA witness Kurt Strunk provides more detail on this issue, it is my understanding and experience that lenders typically require a fixed-rate power purchase agreement ("PPA"), in order to provide certainty with respect to revenue stream, and a long enough PPA term to allow for the debt to be repaid during the PPA term. Reducing the ability of a solar project to obtain debt financing has significant implications for the project's financial feasibility. The 15-year contract term has allowed small QFs to access affordable debt and equity capital. In other words, the 15-year contract term has enabled a capital structure that is affordable to the QF developer and, therefore, that has encouraged QF development.

My personal experience is that QFs with a shorter contract term than 15 years would have a much smaller pool of potential debt and equity investors. Further, I believe that adjusting the avoided energy rate every two years would have the same effect. These issues would be exacerbated in the context of small QFs that cannot achieve the economies of scale—and associated cost reductions—that large QFs can achieve.

In my experience, the Standard Offer, particularly the PPA term and fixed rate, has provided the certainty that has been necessary to encourage QF development in recent years, and this certainty has also played a critical role in driving down the cost of developing solar facilities. When CSE first started developing solar QFs in North Carolina, the market was relatively unsophisticated with respect to the development process, as well as the financing process. The gains that have been made by industry in recent years have helped drive down the cost of solar development in North Carolina. These include: understanding and taking advantage of economies of scale with equipment suppliers; the creation and development of local supply chains and associated service providers related to solar racking, fencing, and landscaping; and the creation of a large, skilled local labor pool trained in installation and construction of solar farms. Additionally, the development of the industry has attracted suppliers, such as Schletter Inc. – a manufacturer of solar mounting systems – to relocate in North Carolina, further driving down costs. The Utilities' proposed modifications to the implementation of PURPA would disrupt this success and would dramatically alter the landscape of companies that participate in QF development in North Carolina and beyond.

Therefore, while solar QF development has experienced success in North Carolina, my experience in the North Carolina market and in investigating other states leads me to conclude that the modifications to the implementation of PURPA proposed by the Utilities—particularly: 1) reducing the term of the standard contract to a 10-year or shorter term; and 2) adjusting the energy rate every two years of the contract term or otherwise providing a rate that is not fixed over the term of the contract—would abruptly curtail the QF market that has been created here.

Q. IS IT APPROPPRIATE, AT THIS TIME, TO ADOPT ANY OF THE MODIFICATIONS PROPOSED BY THE UTILITIES TO THE WAYS IN WHICH PURPA IS IMPLEMENTED IN NORTH CAROLINA?

A. Negotiating a power purchase agreement with an electric utility in North Carolina, in my experience, has been straightforward because very few, if any, revisions to the electric utility's proposed PPA are accepted by the utility. CSE was involved in the development of four (4) large solar QFs that negotiated PPAs with Duke last year, and those projects are moving forward with financing and construction. It is my understanding that subsequent to the negotiation of the PPAs on our four (4) projects, Duke significantly reduced the PPA term it offers to QFs for negotiated PPAs. Because of this recent change, CSE has serious concerns regarding the Utilities' proposed modifications to the Standard Offer, as they would have the effect of requiring any QF greater than 1 MW to negotiate a contract with the electric utility, and I suspect that at the current time, a QF would not be able to negotiate a PPA with a term of sufficient length to allow a QF the reasonable opportunity to attract capital. In light of concerns related to the reduction of the PPA term and the variable energy rate, as well as difficulties experienced in the context of negotiated PPAs, NCSEA cannot endorse any of the Utilities' proposed revisions to the Standard Offer, including the reduction in eligibility for the Standard Offer from 5 MW to 1 MW.

However, NCSEA and its business members agree with Duke's proposal, outlined by Witness Bowman, that a transition to a competitive procurement process for solar generation could be appropriate, as long as the process were subject to specific and well-defined parameters. Even as experienced developers, we are uncertain about whether, going forward, a contract that will allow solar developers to continue with QF development could be negotiated with the electric utilities outside of the Standard Offer. However, we feel that our experience in developing QFs and our ability to drive down costs and find efficiencies would allow us to compete within a well-prescribed competitive procurement process. It is NCSEA's position that a transition to a competitive procurement process could be a reasonable approach to continued solar development in North Carolina, as long as the competitive procurement process: i) obligates the Utilities to procure a specific amount of capacity on an annual basis for a minimum number of years; ii) is administered by an independent evaluator selected and monitored by the Commission; iii) limits participation in the development process by the Utilities and by unqualified developers; and iv) involves a standard contract with general terms and conditions that are commercially reasonable and that afford reasonable opportunities to attract capital. NCSEA's support for a competitive procurement process is predicated on: i) the expectation that the process would be developed in a collaborative stakeholder proceeding; and ii) the existence of a continued opportunity to interconnect small QFs and sell to the Utilities outside of the RFP process.

Q. WHAT IS YOUR RESPONSE TO DUKE'S PROPOSAL FOR REVISING THE STANDARD FOR ESTABLISHING A LEGALLY ENFORCEABLE OBLIGATION IN NORTH CAROLINA?

A. Duke has proposed to modify the standard for establishing a LEO by requiring a QF to progress through the "System Impact Study" process and commit to proceed to a detailed "Facilities Study" in the context of the interconnection process.[11] In support of this proposal, Duke witness Freeman asserts that "[Duke's] experience does not support that it is even feasible for a QF to make a commitment to provide energy and capacity to the utility over a specified future term prior to completing the System Impact Study."[12]

NCSEA objects to this proposal because it would put the QF's ability to establish a LEO outside of the QF's control and would potentially result

[11] Freeman Direct, p. 14, ll 19-22.

[12] Freeman Direct, p. 18, ll 7-10.

in a QF being unable to receive a LEO. As I mentioned previously, over the past twelve (12) months CSE has received only one (1) System Impact Study agreement for our 5 MW ac QFs that are in the interconnection queue in North Carolina. I am not an attorney, but I also believe that this proposal is inconsistent with a recent decision of the FERC in which it ruled that a LEO standard that gave control over the timing of the establishment of the LEO to the utility was inconsistent with PURPA.

Furthermore, I respectfully disagree with Duke witness Freeman that a "QF cannot reasonably make a commitment to sell until completing the initial System Impact Study step of the North Carolina interconnection process."[13] As I previously testified, the QF development process involves many steps, only one of which is interconnection, that require the QF to make significant commitments. The early stages in the development process involve the identification of a suitable site for the facility, the negotiation for site control with the landowner, the completion of environmental surveying and permitting, the securing of land use approvals, and the securing of regulatory approvals. These early stages can take many months, or longer, to complete. Securing rights to the site and all necessary approvals involves significant cost, as well. The interconnection request is typically made very early in the process, after site control has been secured. Engineering and design work must be undertaken prior to submitting the interconnection

[13] Freeman Direct, p. 4, ll 2-4.

request, and a significant fee, in the case of a 5 MW QF, $25,000, must be paid at the time the interconnection request is submitted. Subsequent to the submittal of the interconnection request, a scoping meeting is held with the relevant personnel for the interconnecting utility, as well as the QF's team of engineers, to discuss the request. From the scoping meeting, the request proceeds to the study process. The process of preparing an interconnection request, submitting to the utility, and holding a scoping meeting with the utility can take several months and involve significant expense, depending on the complexity of the interconnection and the engineering and design resources required. Thus, significant commitments—in terms of expenditure of time and financial resources and the securing of necessary approvals—are made toward the development of the QF before the interconnection study process is completed.

However, NCSEA agrees, to a limited extent, with the concern expressed by Duke that information regarding the cost to interconnect is critical to the determination of whether a QF is financially feasible. Given the foregoing, NCSEA is open to a revision to the LEO standard that takes this into account <u>but that does not allow the utility to control the timing of the LEO</u>. Specifically, NCSEA proposes that the LEO standard be revised to allow the QF to provide a Notice of Commitment form to the purchasing utility only after 105 days have lapsed from the interconnecting utility's receipt of the QF's interconnection request, which is the time established under the Interconnection Standard for the utility to complete the System Impact Study process. This would allow the utility the time to conduct the "System Impact Study" were the utility compliant with the timelines set forth in the Commission-approved Interconnection Standard and provide the results to the QF before the QF is eligible to provide its Notice of Commitment form to the utility. It is NCSEA's position that this proposed revision appropriately focuses on the QF's commitment and is not overly beholden to a specific action by the utility.

Q. HOW DO YOU RESPOND TO DUKE WITNESS FREEMAN'S CONCERNS REGARDING "STALE" RATES?

A. Duke witness Freeman gives grounds for Duke's proposals to revise the LEO standard on concern regarding "stale avoided cost rates,"[14] which I understand to mean rates that do not reflect the utility's avoided cost at the time that the QF begins to deliver electrical output to the utility. As I understand Duke's explanation, "staleness" would occur when there is a lag in time between the establishment of a LEO or right to certain biennial rates and actual delivery.

As I mentioned previously, I was part of the stakeholder discussions in 2014 that led to revisions to the Interconnection Standard. One of the key

[14] Freeman Direct, p. 19, ll 1-11.

compromises made by solar developers as part of those stakeholder discussions was to accept strict penalties if a solar developer does not meet the timelines required by the Interconnection Standard. For example, once a developer receives a System Impact Study or Interconnection Agreement from the utility, that developer has a proscribed number of days to respond and either move forward with the next step of the interconnection process, or drop out of the interconnection queue. If the developer fails to proceed with the next step of the process on time, the utility has the right to remove the project from the queue. Although there are no equivalent penalties for the utilities to meet their required timelines under the Interconnection Standard, solar developers agreed to these strict penalties in order to help with the process of clearing "speculative" projects from the queue and in order to help the overall interconnection process work more efficiently.

Because these penalties on solar developers are part of the current Interconnection Standard, I believe that in general, long delays between establishment of a LEO and interconnection to the grid are typically caused by long utility study process timelines, and are not caused by the QF. In my experience, the QF is typically not responsible for and typically seeks to avoid significant delays or lags between the establishment of the LEO and delivery of power. In fact, there is opportunity cost as well as incremental risk to the QF associated with any such delay. If given an opportunity to interconnect and commence delivery sooner rather than later, in most cases, I suspect that the QF would elect sooner. Thus, while NCSEA is concerned about risk to ratepayers of overpayment and has proposed a revision to the LEO standard that reflects this concern, NCSEA submits that the delay or lag that creates staleness does not benefit the QF and, typically, is not created by the QF.

Q. HOW DO YOU RESPOND TO DUKE'S PROPOSAL FOR A STANDARDIZED CONTRACTING PROCESS?

A. NCSEA has reviewed Duke's proposal to standardize the contract negotiation process.[15] In theory and based on my experience with the Standard Offer, a standardized process is appealing, in that it entails certainty and has the potential to minimize transaction costs and time. However, without express limitations on the Utilities' discretion regarding the critical issues of term/duration and fixed rate, a standardized process affords no benefits beyond the process that exists today and has the potential to give rise to disputes and to litigation. Additionally, Duke's proposal appears to suggest that the rates and terms offered would be available for a 60-day period only and would be revised if not accepted in that period. While I am not an attorney, I am concerned that this proposal violates the right of a QF, under federal regulations, to a rate that reflects the electric utility's avoided cost as of the date of the LEO, given the current standard for establishing a LEO in North Carolina.

[15] Freeman Direct, p. 22, l. 6 – p. 23, l. 18.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

4819-2881-1589, v. 11

BY MR. LEDFORD:

Q And, Ms. Harkrader, did you prepare a summary of your testimony?

A Yes, I did.

Q Would you please present that summary?

A I'd be happy to.

(WHEREUPON, the summary of **CARSON HARKRADER** is copied into the record.)

Before the North Carolina Utilities Commission
Docket No. E-100, Sub 148
Carson Harkrader On Behalf of NCSEA
Summary of Testimony

My name is Carson Harkrader. I am the Director of Project Development for Carolina Solar Energy II, LLC, which I refer to as "CSE" and which is a business member of NCSEA, on behalf of which I am testifying in this proceeding.

I earned a Bachelor of Arts with Honors in Political Science from Brown University, and wrote my honors thesis in 1999 on the deregulation of the electric utilities in Rhode Island. I also earned a Master in Business Administration in Finance and Strategy from New York University. Prior to business school, I was employed for eight years on the commercial sales team with GE Energy in Asia and New York. After completing business school, I returned home to North Carolina in 2012 to work with my father at CSE. At this point in time, I have a total of fourteen years' experience in the energy industry and have been the Director of Project Development at CSE for four and one half years. In this role, I oversee the company's solar QF development process. I have been involved in the development of nineteen small QFs and four large QFs. In my years of working at CSE and developing solar facilities in North Carolina, I have had the opportunity to work closely with employees of Duke and Dominion. The utility employees with whom I have worked are dedicated to their work and, in my opinion, have played a significant role in the success of the solar industry in North Carolina. CSE and NCSEA, as well as myself personally, are very appreciative of these efforts and look forward to continuing to work together.

The purpose of my testimony in this proceeding is to respond to: 1) Duke's characterization of solar development as "uncoordinated and unconstrained" and "unmanageable;" 2) the Utilities' proposals to reduce eligibility for the Commission-approved standard rates and contract terms available to QFs (the "Standard Offer") to 1 MW from 5 MW and Duke's proposal to transition to a competitive procurement process to support continued solar development in North Carolina; 3) the Utilities' proposal to reduce the term of the standard contract from 15 years to 10 years and Duke's proposal to offer a variable energy rate and not a fixed energy rate; and 4) Duke's proposals related to the LEO and standard contracting procedures.

First, Duke's characterization of solar development in North Carolina as "uncoordinated and unconstrained" and "unmanageable" does not reflect my experience as a solar developer. Notwithstanding industry's past success in North Carolina, the development of solar facilities is increasingly constrained by a number of factors, including: appropriate and available project sites with access to utility infrastructure; the local permitting and approvals process; and the interconnection process. Regarding the characterization of solar as "uncoordinated," the Utilities acknowledge that solar can provide benefits when located at certain points on the grid; however, information on where solar would be beneficial is not shared with QF developers. Additionally, solar inverter technology can be utilized to provide valuable services to the grid; however, we have not yet been provided the opportunity to work with the Utilities to unlock this value.

Second, in my experience regarding negotiated PPAs, utilities have accepted few, if any, revisions to the PPA contract that they offer a QF. Thus, based on my experience, the QF has little, if any, influence over the terms and conditions of the PPA. CSE therefore has serious concerns regarding the Utilities' proposal to reduce the Standard Offer eligibility threshold, as it would result in any QF greater than 1 MW having to negotiate a PPA. Given the control the Utilities exert over the PPA negotiation process, I am concerned that under the Utilities' proposal, a QF larger than 1 MW would not be able to negotiate a term of sufficient length to allow a reasonable opportunity to attract capital. NCSEA therefore recommends maintaining the Standard Offer threshold at 5 MW. However, NCSEA and its business members find merit in Duke's proposal that a competitive procurement process could be appropriate, as long as the process were subject to specific and well-defined parameters and Commission oversight. NCSEA's support for an RFP is predicated on: i) the expectation that it would be developed in a collaborative stakeholder proceeding; and ii) the existence of a continued opportunity to interconnect small QFs and sell to the Utilities outside of the RFP.

Third, North Carolina is one of the few states in the country that has ensured that certain critical policies, including long-term contracts and fixed pricing, are in place to encourage QF development. Solar project lenders typically require a fixed-rate PPA, which provides a certain revenue stream, and a long enough PPA term to allow for the debt to be repaid within the PPA term. My experience is that large QFs with a 10 year contract term have a much smaller pool of potential debt and equity investors than projects with a 15 year PPA term. Further, I believe that adjusting the avoided energy rate every two years would even more significantly, and likely completely, reduce the ability of a QF to obtain financing. Additionally, while I am aware that a small number of large QFs have been developed in spite of a 10-year PPA term, small QFs certainly do not offer the same economies of scale and efficiencies as large QFs. Thus, the fact that some large QFs have been developed in spite of a 10-year term does not provide a basis on which to conclude that a 10-year term provides reasonable opportunity to attract capital for all QFs.

Fourth, I respectfully disagree with Duke's assertion that a "QF cannot reasonably make a commitment to sell until completing the initial System Impact Study step of the North Carolina interconnection process." QF development involves many steps that require significant commitments, some of which come before, and some after, the System Impact Study. However, NCSEA does agree that information regarding the cost to interconnect is critical to the determination of financial feasibility, and has proposed a revision to the LEO standard that takes this into account but that does not allow the utility to control the timing of the LEO. NCSEA's proposal prohibits the QF from providing a commitment form to the utility until 105 days from the utility's receipt of the interconnection request – by which point the utility should have provided the System Impact Study to the QF. NCSEA's proposal appropriately focuses on the QF's commitment and is not beholden to any specific action, inaction, or exercise of discretion by the utility.

Finally, NCSEA has reviewed Duke's proposal to standardize contracting procedures for large QFs. In theory, standardized procedures are appealing to NCSEA. NCSEA's support for standardized procedures is predicated, however, on the maintenance of a separate standard for establishing a LEO that does not involve the power purchase agreement. Additionally, without express limitations on the Utilities' discretion, a standardized process has the potential to give rise to disputes and to litigation and affords no benefits beyond the process that exists today.

4834-6758-2534, v. 3

MR. LEDFORD: Thank you. The witness is available for questions.

CHAIRMAN FINLEY: Cross examination.

CROSS EXAMINATION

BY MS. FENNELL:

Q Good afternoon. Heather Fennell with the Public Staff.

A Good afternoon.

Q Ms. Harkrader, on pages 11 through 12 of your testimony, you discuss some different times that projects are taking in the interconnection queue and specifically you mentioned a project in Richmond County.

A Uh-huh.

Q And you mentioned that the interconnection request was submitted in July of 2015, just approximately 21 months ago from now, and the project has still not received its System Impact Study; is that correct?

A That is correct.

Q And you also state in your testimony that otherwise the project is ready to move forward with financing and construction.

A Correct.

Q Can you talk a little bit about why you're not able to move forward with financing at this time?

A Yes. So one thing that we do, as was mentioned and is mentioned in my testimony, this project has not received its System Impact Study agreement yet from the Utility. There are a couple of things though that we do before we receive that System Impact Study that allow us to invest into the project which we've done. The first of those things is that we have, and it's part of the interconnection procedures, we have a pre-request that we can request from the Utility, and it's a great process that we use that the -- we send in $300 to the Utility, a request showing this project and we receive back information on the size of the substation that's nearby, confirmation that it's the Utility that we think it is, the distance from the project to the sub, whether that line is heavy three phase or light three phase which might impact the cost to connect, the number of QFs that are in queue on that sub ahead of us on that transformer, and then we check the queue and see if they're interconnected or if they're in study. So we look at all of that information and then we also have our electrical engineer do a review to give us an estimated cost of what we think that interconnection might be. And based on that in my testimony and then in my response to one of Duke's data requests, I described the investments that we've made into that project. We have sought the local zoning approvals that we needed for the town and the county for this one because the line went through the project. We have done our environmental work. The Army Corps of Engineers has come out to the site to review all of those things. So we have a good idea of what we believe the system impact will be in terms of costs. We have an idea of the sub that will be connected and we know that there's that transformer, we believe should be able to accept the QF. But without -- you know, in terms of going to an investor for financing they may say, yes, we're interested; yes, this all looks great, but without that actual System Impact Study and even, more importantly, the Interconnection Agreement which we can only get from the Utility once we have that System Impact Study. Without that we could have preliminary agreements about financing but we certainly could not move forward with any kind of -- no one, for example, would say sure we'll build this project and hope that the Utility will provide the Interconnection Agreement later so it will connect, you would never be able to get financing in my experience. I should really only speak to my experience but we've never been able to have a project move forward into construction and committing the capital for construction without having the System Impact Study and the Interconnection Agreement executed.

Q Also, in your experience, would you sign a PPA with liquidated damages prior to processing through the interconnection process?

A My company has two experiences where we have signed a PPA and in -- because typically, as I mentioned in my full testimony, we're an early stage developer so we get everything ready for the project to then be financed and constructed, and typically the PPA is signed at that time. But we did have two times when we signed PPAs and in those experiences we had received the

Interconnection Agreement already. That's -- until you have that Interconnection Agreement from the Utility it's hard to sign a PPA.

Q Also on page 12 of your testimony, you note that the interconnection process for distribution-connected QFs remains on hold at this point. Could you talk about -- a little bit about what you mean by that?

A Sure. So -- yes, I can. So the first thing I want to say about that is just referring back to what I mentioned in my full testimony and in my summary which is that in the last four and a half years of my work at CSE I've worked daily, weekly, monthly with representatives of the Utilities. We've worked very hard together on a number of our projects and I am very grateful for all of the work that they have done which has resulted in a number of projects on the grid that my company developed. So this is certainly not a matter of, you know, none of our projects have ever gotten through the queue. We've had a lot of success in the past that we're hoping to build on.

I was a member of a Stakeholder

Working Group in 2014, that worked with the Utilities and other developers to come up with new interconnection standards, and we all worked very hard on that. And that -- can I refer to the -- can I refer to -- so I think Witness Bowman had a chart in her testimony on page 21, so in my full testimony I refer to a project that we did in 2012 that got through. From the time we applied for the project to go online and it got its fully signed Interconnection Agreement within about six months, so that was in 2012, and in 2013 and 2014, we saw the applications onto the queue growing. And, like I said, I was part of the Stakeholder Working Group that looked at, you know, how do we control applications on the grid. The Commission approved, of course, the results of that in May 2015, which intended to put more constraints on the QF developer. We went from a $1,000 application fee up to $25,000 for a 5-MW QF. If we made material modifications to our application, instead of being restudied and staying in the queue, we would go to the back of the queue under the new standards. Once we receive our System Impact Study, we have a certain number of days to respond, as a QF to respond. If we don't respond to the Utility in those days we're out of the queue. So there were a number of new constraints put on QFs that we agreed to in that 2014 stakeholder process in order to help the queue work better. And I think in 2015, the number of applications onto the grid went down pretty substantially, looking at both DEC and DEP together. I don't have a slide for Dominion but in our experience through 2012, we were getting System Impact Studies back fairly quickly 2013 and 2014, that process slowed somewhat, it would take more months to get the System Impact Study and Interconnection Agreement back. 2015 -- and I'm referring specifically to the DEP distribution queue at this point. And then -- so throughout 2015, we were continuing to receive -- every month maybe we would get one project back. And then at some stage in the spring of 2016, so about a year ago, we just stopped getting any projects out of the DEP distribution queue. So when I mentioned on hold that was what I was referring to was our company's experience that since about a year ago it's become very uncertain to us when any projects might come out. We have one project that's been in that queue for about 30 months and that project we have just received notice that it's going into advanced study. But a number of those projects are Project A or B on that substation so they are in System Impact Study. We just -- it's very unclear when they will be coming out of the queue.

Q When you're in process how much information are you able to get from the Utility about where you are in process?

A The Utilities publish their queue. It's updated I think monthly or bi-monthly so we can check that queue. We can look back to our pre-request that I mentioned earlier that shows us what projects are ahead of us on that substation in terms of study. We can look up their status. So we can -- from their published queue we can see what's ahead of us, if they're connected, if they're not connected. But the only thing that we know about our project is simply that it's in study.

Q And you mentioned in your earlier answer that

should a QF fail to meet a deadline that's part of the process they'd be kicked out of the queue?
A Correct.
Q What happens if the Utility fails to meet some of the guidelines or the timelines provided for I think in the interconnection --
A We talked about that a lot in the stakeholder proceeding in 2014, and certainly the QF developers' concern was that there was going to be no, no consequences if the Utility did not meet the timelines that they were -- that were in the new interconnection standards that we were proposing; there was no fee or any kind of consequence. But as developers we decided that if we accepted the consequences that were in the standard it would help the queue move better and we decided in good faith to go forward in the hopes that the queue would continue to improve.
Q One last question. As you mentioned at the end of your summary Duke has proposed a standardized contract and procedures and you mentioned that you may have concerns about that. Would you hope to engage in a process or like to contribute if there are sort of a standardized contracting

process that's developed?

A Certainly. Certainly. We do think that the Commission should look at a standardized process and we'd be happy to be involved.

Q Again in your summary you mentioned that there should be expressed limitations on the Utilities' discretion. At this time could you express some of those limitations you would like to see?

A I think one of them is just about, what I mentioned in my summary about just our concerns about the LEO and the timing of the LEO.

MS. FENNELL: Okay. Thank you.

CHAIRMAN FINLEY: Companies.

MR. BREITSCHWERDT: Thank you.

CROSS EXAMINATION

BY MR. BREITSCHWERDT:

Q Good afternoon, Ms. Harkrader.

A Good afternoon.

Q Brett Breitschwerdt on behalf of Duke Energy. How are you?

A I'm fine. How are you?

Q Doing well. So you in your summary and in your testimony you mentioned your company, Carolina Solar Energy, and would it be fair to

characterize your company as a pioneer in developing solar in North Carolina?
A Oh, people have said that. Yes, I've heard that.
Q And when was the company first formed?
A So my father started Carolina Solar Energy in 2004.
Q And thank you. And so you identify in your testimony that the first -- or the largest project that y'all had done in 2008 was a 75-kW project --
A Yes.
Q -- is that correct?
A That is correct.
Q And that was the largest project at that time in the southeast?
A That is correct.
Q And was it a PURPA project or was it a net metering project?
A I was not here at that time. I know there was a special PPA for that one. It may have been under the RPS.
Q So let's say the Renewable Portfolio Standard --
A I --
Q -- which was enacted in 2007?

A I believe so.
Q So that was of the early, early development --
A Yes. That one was also on a brownfield site so it received a grant because it was a -- it's near the PNC Arena. There was an area that had had some waste dumped there and so that is actually built to not have any pieces that go down into the ground.
Q So the state purposely put in policies to incentivize development potentially at that location or to incentivize that type of project?
A Yes.
Q And so, I think, if I'm reading your testimony, you've kind of evolved in your development and by 2012, that was the time that you started developing 5-megawatt standard projects; is that fair?
A I believe we started developing five megawatts in 2012.
Q Okay.
A But 2012 is when we stopped building projects. So my father, Richard Harkrader, started the company and he was the general contractor and so some of those very first projects he actually

built himself and financed himself, and as the projects got a bit bigger he decided he didn't want to be on the site building them anymore.

Q Understood. Okay, thank you. We'll get to the building shortly. But I'm just -- I'm trying to track through the evolution of your business and the solar because I think it's important to identify that for the Commission in terms of what we're trying to do in evolving the way the marketplace is today. So you started developing 5-megawatt projects and then you evolved from there and now you're developing large transmission-connected 50-megawatt projects. I think you said you successfully negotiated four PPAs with Duke Energy last year; is that correct?

A Four projects. Four large transmission QFs that we developed got PPAs and two of those PPAs we negotiated and two were finalized by the company that bought the development asset from us that partnered with us to invest into the project.

Q Okay. So --

A So four total that we had developed, yes.

Q And have you read Ms. Bowman's testimony about the history of the standard offer and how it's evolved since PURPA was first initiated or created in the early '80's?

A I did read her testimony, yes.

Q And would you agree with me that there was no 5-megawatt standard offer from 1980 to 1985? And if you don't remember it we can --

A I don't know.

Q Okay. And just subject to check the evolution was from 1980 to 1985, there was no standard offer, QFs would get all the way up to 80 megawatts. And then in '85, it evolved to five megawatts for some technologies for a 15-year term. And then in the '90's, it evolved again, I think '96 through early 2000's where certain facilities were allowed to have a 5-megawatt standard offer but only for a five-year term. And then in 2005, it evolved again and so you had solar and other renewable technologies becoming eligible for the standard offer at that point in time, and so over time the standard offer has evolved. Would you agree with me that your business over the last few years has evolved as we just talked about from small 75-megawatt (sic) projects to 5-megawatt projects now to much larger transmission-connected projects?

A Yes. From the 75-kW that was our first, yes, it has evolved and we've -- our projects have grown in size.

Q And so kind of the regulatory construct has not evolved at this point but the economics in the development business has evolved to the point where you're now building larger projects outside of the standard offer?

A I don't know if I can say that the regulatory process has not changed but --

Q Has the standard offer changed since you've been in the development business?

A I mean we went -- well, we did go through that proceeding in 2014, where we had the new avoided cost rates so that was the change.

Q But the five megawatts and the 15-year term and --

A Yes.

Q -- and the -- kind of the nuts and bolts of what the standard offer is hasn't evolved since 2005, is that -- or to your knowledge since you've been in the business?

A I would agree.
Q And you say in your testimony that you investigated other states where there were potential development opportunities. Y'all are a North Carolina company but you looked outside of North Carolina and you prefer to continue developing in North Carolina; is that a fair characterization?
A That's correct.
Q And so do you have a feel or would you be able to provide the Commission any insight into whether five megawatts is a standard size in other jurisdictions or whether that's unique to North Carolina?
A I believe the five megawatt is unique to North Carolina. And I thought that the Witness Johnson did a good job of outlying what happens in some other states in terms of PURPA. So I would maybe just refer back to his testimony in terms of other nearby states and I would agree with him. I think he made the statement that without a certain level of baseline kind of contracts, standard contracts, companies simply didn't go into those other states to then go through the

process -- go through this process we're going through now.
Q Well, and so --
A Which included us, you know, we chose not to.
Q Would you --
A Although other company -- other -- of course many solar developers have gone into South Carolina and Georgia and other states that are now catching up with North Carolina in terms of the number of -- amount of solar that they --
Q And I think you --
A -- are installing.
Q I'm sorry to interrupt.
A Oh, sure.
Q I think you represented in discovery that South Carolina and Georgia were the two states that you looked at; is that correct?
A We did, yes.
Q And so in looking at Georgia you felt at that time the standard offer wasn't a viable option for you to develop in that state --
A That's right.
Q -- is that correct?
A That's right. And some other developers that we

know did decide to go into South Carolina and Georgia and they're now doing very well there so --

Q And would you agree that in Georgia the development has been driven by a competitive procurement process and not by the standard offer, not by the PURPA construct?

A Yeah, I think one of your witnesses had a chart on that.

Q Thank you. So I just wanted to kind of circle back to the point we were discussing a moment ago about the 5-megawatt standard offer and whether that's unique to North Carolina. I think that's a significant point in this case and I'd like to talk with you about whether you have knowledge of other states and whether any other projects that you're aware of are built in the range of five megawatts and how many of those states are building five megawatts connected to the distribution system which you talked about a moment ago?

A I don't know. I don't know that I can answer.

MR. BREITSCHWERDT: And so -- I'd like to introduce one cross examination exhibit, please, sir.

So while she is passing this out, if it's all right, I'll ask a few questions just to introduce it.

BY MR. BREITSCHWERDT:

Q Are you familiar with the Energy Information Administration?

A Yes.

Q And are you familiar with the Form EIA-860 which is a form that generators of all types are, once they're placed in service, required to file the EIA to track the number of projects of generation types and technologies --

A Yes.

Q -- generally?

MR. BREITSCHWERDT: Mr. Chairman, at this time I would like to mark this as Harkrader DEC/DEP Cross Exhibit 1, please.

CHAIRMAN FINLEY: It shall be so marked.

Harkrader DEC/DEP Cross Exhibit 1

(Identified)

BY MR. BREITSCHWERDT:

Q So if you could peruse quickly the first four pages of very detailed information and, if you wouldn't mind, accept subject to check that the Companies have done the math right. This represents -- if you'll see at the top this is limited to solar generators state-by-state non-utilities so these are QF independent power producers or, as it's identified here, IPP Non-CHP. And if you'll notice in about the fifth column over the nameplate capacity is 5.0. So this represents 5-megawatt nameplate projects across the entire United States. And if you wouldn't mind, flip to the last page.

A I see, uh-huh.

Q So the number of projects for North Carolina, which is about half way down, is 135; is that correct?

A Yes, I see that.

Q And do you see any other states in the southeast listed here?

A No.

Q So would you agree with me that based on this data developed by the EIA as of the end of 2015, there were no 5-megawatt projects in any other state in the southeast besides North Carolina?

A That is correct. But, of course, I would also say that there are a lot of other states in the southeast that are taking a lot of actions to grow their solar, what's, you know, what's coming on to their grid in solar whether its through QFs or through other means.

Q Okay. And I think just a couple of questions on that. So through other means, like a Renewable Portfolio Standard?

A Yes, Renewable Portfolio Standard. I know Georgia Power has put forward, as you mentioned, competitive procurement. I read in the *Business Journal*, I don't know that this is -- I can't speak for the *Business Journal* but that Georgia actually put on more solar onto their grid last year than North Carolina.

Q And do you -- excuse me.

A So whether it's through QF or through their utilities or their legislators encouraging solar, it's by various means, but it's not -- other southern states are certainly also wanting to encourage solar.

Q And would you agree that the Georgia model, to your knowledge, is not PURPA, it's through a procurement process where its larger generators connected to the transmission system and, based on this data, would not be five megawatts in

size, at least historically?
A I definitely don't know whether it's distribution or transmission or the size of the individual projects. But I do understand that it's a competitive procurement process which, as part of my testimony, I think we've said we were interested in doing in North Carolina as well.
Q If you could turn to page 4 of your testimony, please, line 18, where you discuss your company and the kind of the role that y'all play as an early stage developer.
A Uh-huh.
Q And so you have discussed as part of your testimony the commitments that CSE makes and the development process and what you do as an early stage developer, and Ms. Fennell for the Public Staff asked you some questions about the LEO process or what has historically been done. How many notice of commitment forms has Carolina Solar submitted to Duke Progress or Dominion in the last two or three years?
A (Looking at counsel for NCSEA) Should I make a guess or should I just -- I don't know.
Q To the extent that you know, do you have a

general, is it more than five, is it more than 10?

A Because we're an early stage developer sometimes we partner with the investor very early in the process, sometimes later. So sometimes it's us submitting the LEO and sometimes it's someone else submitting it on behalf of a project that we developed. I think I mentioned in my summary that I was involved in the development of 19 small QFs so certainly all of those would have submitted LEOs. I don't know whether our company or our investor partner would have submitted each of those.

Q When you say a small QF, you mean a 5-megawatt --

A 5-megawatt --

Q -- standard contract, right?

A Yes, correct.

Q Well, let's talk about those. So nineteen 5-megawatt projects - for each of those projects, your role as you state in your testimony here is that you initiate the interconnection process, you obtain permitting and then you work with other companies as partners who complete finance and construction of the solar farms?

A That's correct. And sometimes if we partner with them very early they actually would have even submitted the interconnection application.

Q Okay. So it's not your role to actually proceed with the development to the point where you're going to enter into an Interconnection Agreement and evaluate the cost of whether or not to move forward with the generator; is that correct?

A That is correct.

Q And so --

A But we are, of course, partnered very closely as all of that happens and have a big vested interest in that.

Q But -- and so you've submitted notice of commitment forms for these generators but you --

A LEOs, yes.

Q And a LEO is a commitment --

A For --

Q -- it is a legally enforceable obligation by the QF -- well, let me ask the question. Would you agree that a LEO under PURPA is a legally enforceable obligation and commitment to sell the power over a specified term?

A I am not an attorney. I think I would only just refer to what's in the LEO form.

Q Okay. Would you agree that the commitment that you have made does not result in Carolina Solar entering into contracts to build the generator?

MS. MITCHELL: I'm going to object, Chairman Finley. Could you -- the question is unclear. What -- it's not clear what counsel for Duke means by contracts to build. I mean, there are many different contracts involved as you know. Could you just specify exactly which contract you're interested in?

MR. BREITSCHWERDT: Sure. Any contract to build. An EPCT contract to build the -- any material contract to build the generator.

A We -- our company does not enter into those contracts, no.

BY MR. BREITSCHWERDT:

Q So you submit a commitment form to the Utility committing to deliver power in the future but you don't enter into contracts with third parties to build the generator; is that correct?

A That is correct.

Q And so does Carolina Solar, for these projects you're committing to build and deliver power, obtain financing for construction of these generators?

A No, we do not obtain financing for the projects. So our goal, and as I mentioned in the answer to one of the other questions, was we want to make sure that the projects -- we've received the pre-request from the Utility that we know the substation it's going to connect to; we know where it is; we know what capacity is on it; we know what the queue is there; we have an estimate of the interconnection costs; but our company's scope does not include the financing. So we're trying to deliver a project to an investor that has all the -- all the qualities that will make it a financeable, buildable project.

Q Okay. And in your summary you represented that you had concerns that reducing the standard contract to one megawatt would, in a 10-year term, would challenge the ability to obtain financing for QFs?

A That's definitely true. In my experience with the two projects that we did sign PPAs for that I mentioned, we did look at investors for those projects and we certainly saw -- we talked with the groups of investors that, to my knowledge, were interested in 15-year PPA projects, and these had 10-year and we were told by a number of them, no, we will not look at these projects with the 10-year term. So while they were able to -- we were able to find an investor, the pool of investors that would look at these projects with a 10-year term was much smaller than what would look at them with the 15-year term.

Q But you don't actually go out in the normal course and obtain financing for --

MS. MITCHELL: Objection. Asked and answered.

CHAIRMAN FINLEY: Overruled.

A Correct. We do not finance the projects.

Q And so, to the extent you have knowledge of these small -- the financing of these smaller projects, it would be based on historical experience for other projects from in the past, is that fair to say, a year or two ago?

A I don't quite understand the question.

Q Is it fair to say that since you're not financing these smaller QFs that your representation that it would be challenging to obtain capital is based on other experience and not based on your specific experience as a Director of Project Development to go obtain that capital?

A Correct. But the experience that I have is with our two larger projects that had a 10-year PPA that we went out -- we didn't look to finance the projects ourselves but we looked to find the investor who would be able to put all of that together. So I do not have experience financing the 5-megawatt projects that have the 15-year PPA. I just know that we've worked with investors on those that have gone out and financed them.

Q And you were --

A Did I answer your question?

Q Well thank you. You were able to finance those 10-year terms?

A We did find investors that were willing to work with those two projects. Yes, we did.

Q Thank you. So a couple of minutes ago I asked you a few questions that just to kind of check off that in your role. As an early stage developer you submit a commitment to -- you submit a notice of commitment form, which is intended to commit to the project and to commit you to avoided cost rates; is that correct?

A Correct. Sometimes, as I mentioned, it has been us if we own the development asset at that stage of development, and sometimes it's been the other party that we're working with if they owned that asset that early, the development asset, then they would submit the LEO.

Q I'm just going to go through this quickly to summarize but I think your testimony was that you don't normally enter into the material contracts to construct the generators or financing contracts for the development of the generators or other material contracts related to the process of developing generators, like material, panels or other invertors or other equipment. Is that a fair characterization?

A Yes. In the data request I think you guys asked -- or Duke asked me that question and I responded with some information on the contracts. We do enter into with our attorneys that do the permitting of the projects for us, with our electrical consultants, with our civil engineering consultants that create the site plans, with our environmental consultants that go out and do the site prep work and engage with the U.S. Army Corps of Engineers. So we enter into all of those contracts but our company does not enter into the EPC contract or into the financing contract.

Q So when you're committing to deliver power over that future term, but you're not committing to build the generator or to -- how is a utility able to rely on that commitment that that power will be delivered?

MS. MITCHELL: Objection. I don't -- the question is not clear. What you mean by rely?

CHAIRMAN FINLEY: Overruled. See if you can answer it. I think she can answer the question.

A Can you repeat it?

BY MR. BREITSCHWERDT:

Q Sure. You are making a commitment to sell power at a future date over a specified term; is that your understanding of what a notice of commitment --

A That is my understanding --

Q -- to sell is?

A Yes. Yes.

Q Okay. And when you do that and you haven't obtained financing, or equipment, or the inverters, or other materials needed to build the generator or to interconnect it, you don't know what your upgrade costs are going to be. How are you able to make a commitment to deliver power at a future date over a specified term?

A I think -- what I would say is that -- as I mentioned we do have the pre-request from Duke that has a lot of -- or from Dominion that has a lot of information about the project, the substation, the interconnection route. We have information from our electrical engineer. The electrical engineer I work with a lot worked for a number of years at Duke Energy Progress and so was able to give us I think pretty good estimates as to what the costs will be to interconnect. We also have experience with previous projects and understand, you know, and we also are getting a lot of feedback from our partners as to what panel prices are at that time and different things like that, and so I think that we rely on all of those things to make that LEO commitment. But I do mention in my full testimony that certainly NCSEA has proposed that we wait to submit the LEO until the 105 days when the Utility could provide that System Impact Study giving us further assurance in order to establish the LEO.

Q Let me ask you a different way. You said earlier in a response to some questions from Ms. Fennell that an investor or someone who's buying a project from you won't buy that project without an Interconnection Agreement; is that correct?

A Well, the word "buy", I mean, we often have investors -- investors would prefer to sign up with us much earlier rather than later and so "buy" is kind of a difficult -- I mean it also depends on when -- is it when they sign the contract with us; is it when we're fully paid; is it, you know, when does the "buy" happen. But they would not be able to go out and get financing is I think what I was saying until they had the Interconnection Agreement.

Q So let me ask you a different way. Until the QF -- until the solar project has been developed to a different point in time, which we can say is after the Interconnection Agreement is signed, after upgrades are paid for, how does the Utility know that they can rely on that power? And by rely on that power I mean that the project is going to be financed and sold. Is there any -- if you can't get financing at that point in time how can you commit to deliver power at the point in the future?

A I think I would just refer back to all of the information that we've collected at that time on the ability of that QF and our knowledge of the market.

Q And so if you can turn to page 20 of your testimony, line 10, please.

CHAIRMAN FINLEY: Mr. Breitschwerdt, how much more time do you have there, sir?

MR. BREITSCHWERDT: Five minutes.

CHAIRMAN FINLEY: Make good use of it, please.

MR. BREITSCHWERDT: Yes, sir.

BY MR. BREITSCHWERDT:

Q So at line 10 you make the statement that you disagree with Mr. Freeman that a QF cannot reasonably make a commitment to sell until completing the System Impact Study of the interconnection process. And then I'd also like to point you to a statement on page 21 where you make the point that -- this is at line 16 -- that the cost to interconnect is critical to determining whether a QF is financially feasible. Do you see that?

A Yes.

Q Okay. So if you don't have the information about the cost to interconnect and you're alleging that you're making a commitment to sell, do you know at that point in time, prior to receiving the result of the System Impact Study, whether the project will be financed or constructed, or is viable to deliver that power in the future?

A I think I would just -- yes, I think I would go back to the process that we go through with the pre-request. All the data that we get from the Utility about the substation, the, you know, what the lines between the project and the substation, whether they're heavy three phase or light three phase, the distance, and the estimate that we could get from our electrical engineer consultant on that information. So while we do not have a System Impact Study that's the real number from Duke, what we have is our best estimates based on our experienced consultants at that time.

Q So if you have that information wouldn't it be reasonable to rely on that information and sign a Power Purchase Agreement and commit to deliver power to the Utility?

A That is not typically the way we operate, no.

Q And why is that?

A And I think one reason and one thing we ran into -- I mentioned we had two projects where we did sign the PPAs, we took those projects much further in the process. One thing we ran into was the PPA has a date when you need to start delivering power and so we were working with a group at Duke Energy that created those PPAs and then we were also, of course, working with a group at Duke Energy that was creating the Interconnection Agreement. And it was very important to us that the date that we were going to be given in the Interconnection Agreement as to when we could turn on the solar farm was going to match up with the date in the PPA when we were committing to deliver power. And until Duke Energy could complete the studies and tell us we'll turn you on at this date, we'll turn on your project at this date, it was kind of tricky because we had a timeline to sign that PPA, and it was very tricky to try to understand well when are we going to be able to commit to sell this power until Duke tells us when they could turn the -- turn the project on. So there are -- I believe that's one of the reasons that QFs typically wait to sign PPAs until they have the fully executed Interconnection Agreement with the date that says that Duke is committing or Dominion is committing to turn the project on at a certain time.

Q Thank you. And so you stated earlier that you're experiencing -- this on page 11 and in your response to Ms. Fennell -- some challenges in projects progressing through the interconnection queue and that you identified a specific project in Richmond County I believe where you stated that you have not received an interconnection study, System Impact Study from the Company in 20 months; is that correct?

A That's correct.

Q And do you know whether that project at this point in time is a Project A, B or is it on hold?

A I believe it's a Project B and that is because we went to, you know, we got the pre-request that showed the queue numbers of the projects that were ahead of us in queue on that particular substation and then we compared it with the monthly status, queue status that Duke publishes on your website and saw which projects had been already connected and which were still in study. So it looks like there is one project still in study ahead of us. And we have a Duke Relationship Manager that I email with on a frequent basis who's responsive and, as I mentioned, great to work with, and so I wrote to him and I said could you confirm that we're a Project B, and I believe he wrote back and said yes. But that -- when we track these things I mean we're tracking that as a Project B based on our reading of the queue.

Q Okay. So and this project may very well have been further down in the queue as a Project C, D, interdependent at some point in the past; is that correct?

A I've been tracking that particular project for a year and I know that a year ago we were in the same B position.

Q Okay. And would you agree that the Company has implemented new technical screens and processes to better evaluate the system reliability challenges that were discovered last summer and that were addressed with the solar community?

A I am aware that there are some new screens that are being implemented.

Q And has the Company -- you mentioned your relationship manager -- has the Company made other good faith efforts to work with Carolina Solar and other solar developers to keep them apprised of the process in terms of kind of what the screens are, how they're being applied and work with the interconnection customers to ensure they have information about where their projects are in the process?

A That's a tough question. There have certainly been a number of technical discussions and meetings about those screens and what they are and I have not participated in all of those technical meetings.

Q Did you participate in the technical meeting that was held last Thursday?

A I -- someone from our office listened into that
but I did not.

MR. BREITSCHWERDT: Okay. I think that's all I have. Ms. Harkrader, thank you for your kind of good faith --

CHAIRMAN FINLEY: Redirect.

MS. MITCHELL: No, sir.

CHAIRMAN FINLEY: Questions from the Commission?

EXAMINATION

BY COMMISSIONER BAILEY:

Q Good afternoon.

A Good afternoon.

Q Just one question for you. Could you -- and you
may not be able to answer this -- can you explain
to me the difference between a light three phase
and a heavy three phase?

A I am not an electrical engineer so I would only
just say that a heavy three phase is capable of
carrying more power. I really don't -- but I do
know it can impact, depending on the size of the
QF and the distance from that project to the
substation, it can affect the pricing. So it's
helpful information that we get from the Utility.

COMMISSIONER BAILEY: Thank you.

CHAIRMAN FINLEY: Questions on the Commission's question?

(No response.)

Let's see, I believe we have a DEP/DEC Harkrader Cross Examination Exhibit Number 1. Without objection, we will introduce that exhibit into evidence.

Harkrader DEC/DEP Cross Exhibit 1

(Admitted)

CHAIRMAN FINLEY: And, Ms. Harkrader, thank you for coming and you may be excused.

(The witness is excused.)

CHAIRMAN FINLEY: We'll come back tomorrow at 9:30 and pick up the Public Staff panel.

(WHEREUPON, the proceedings were recessed.)

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
Court Reporter II