PLACE: Dobbs Building, Raleigh, North Carolina

DATE: October 30, 2013

DOCKET NO.: E-100, Sub 136

TIME IN SESSION: 2:00 P.M. TO 5:15 P.M.

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

IN THE MATTER OF:

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2012

VOLUME 3

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

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

COMMISSIONER BROWN-BLAND: We're back on the record. Come to order. So when we left, we had completed redirect of this witness, and so are there questions from the Commission? Chairman Finley?

EXAMINATION BY CHAIRMAN FINLEY:

Q Mr. Rabago, I'm looking at this report that has been report -- was filed with the Commission that we've had some discussion about.

A Yes, sir.

Q Who is Crossborder Energy?

A I just know the principal of it, Tom Beach. He's a consultant based in, I believe, California. And I've actually -- never actually physically met him. I've talked to him on the phone and exchanged emails with him in relation to other studies.

Q Well, who is Mr. Beach?

A I just know he's the author of the study and the principal of Crossborder Energy, sir. I don't have --

Q Well, it says Crossborder Energy, Comprehensive Consulting for the North American Energy Industry. For whom do they consult?

A I know of their -- they have done consulting work for Vote Solar. They were retained by Vote Solar in the California docket. And I believe they did a study in -- let me think, let's see -- California. They did a study in Arizona. It may have been paid for by Vote Solar as well. And this study. I'm not sure whether -- those two come to mind immediately. Maybe -- oh, Xcel as well -- I'm sorry -- in Colorado.

Q This is captioned as a report. Who paid for it?

A North Carolina Sustainable Energy Association, my client, did, I understand.

Q And when did you first know that this report was on the way?

A I'm trying to think how much involvement I had. I -- around the time that I was discussing -- I want to stay sort of away from attorney/client things, but around the time that I was discussing becoming an expert witness, I know that I gave Mr. Youth names of some firms that I knew did this kind of evaluation, CPR, Crossborder, mentioned a couple of others. I remember, over the course of the couple of months that I've been working with Mr. Youth long distance, we -- he reported that they did secure their services, I can't remember the date, that they would be preparing a report, I can't remember the date, and then I became specifically aware three days -- four days -- three days -- four days, because it was a weekend, before it formally went public that Tuesday a couple of weeks ago.

Q You say "went public." How did it go public?

A I believe that -- that there was a press release issued by SEIA, Solar Energy Industries Association, I think, was the -- was the caption for the press release.

Q And what is this report to be used for exactly?

A I think the -- the idea for you is that it is a report that uses as much as possible, given sensitive material limitations, North Carolina specific information in the kind of framework that has been used in other places to assess the costs and benefits of solar. This goes a little beyond the typical -- in some ways it's a little different from a value of solar study, as I've had experience with, in the sense that it does not include the cooperation of the utilities, but -- so it was done sort of externally, involved utility data. It also tries to quantify the costs, which has been done in a couple of places like California, where they were evaluating the net metering program for cost effectiveness, but is not always a part of value of solar studies.

Q Did you have any role whatsoever in the compiling of this report?

A I did not. You mean -- like I did not direct what should be in it or the content or the avenues or the data. I was separate from that.

Q Is this to be published in any publication, to your knowledge?

A I don't know that -- I don't know.

Q Has it been peer reviewed or anything like that?

A I don't believe so, sir. I don't -- I see no indication of that.

CHAIRMAN FINLEY: All right. Thank you. Thank you very much.

THE WITNESS: Yes, sir.

COMMISSIONER BROWN-BLAND: Commissioner Patterson?

EXAMINATION BY COMMISSIONER PATTERSON:

Q This is just a point of clarification. I'm trying to understand something. In your analysis, are you saying that the qualifying facilities and like a solar panel that I'd like to put on my roof are the same -- same thing?

A Well, it -- yes, sir, I actually am. It turns out that when it comes to the value of a unit of solar generated electricity, it has the same value to the utility by -- if it's not the utility paid, it has the same value to the utility regardless of the solar facility it came from, because the fundamental nature of this value of solar approach is what costs do you avoid. It is a hard, a marginal avoided cost approach.

Q My rooftop solar wouldn't be a qualifying --

A Well, actually it could be. In some states where utilities have made it particularly hard on customers to put solar systems on their roofs, one of the only options available is to use the self-certification provision that FERC authorizes for solar -- for solar systems, and make yourself a FERC QF in order to obtain at least the option of the utility having to buy your energy at the avoided cost rate. So technically speaking, you could self-certify your facility. It would -- it might require you to add another meter and then start looking like you were having a solar business on your roof, but you could end up down that path with a particularly sort of resisting utility.

COMMISSIONER BROWN-BLAND: All right. Any other questions from Commissioners?

(No response.)

COMMISSIONER BROWN-BLAND: Questions on the Commission's questions?

(No response.)

COMMISSIONER BROWN-BLAND: Okay.

MR. YOUTH: I've got questions. Do I get to go last or --

COMMISSIONER BROWN-BLAND: If you have -- does anybody else have questions on Commission's questions?

(No response.)

COMMISSIONER BROWN-BLAND: Mr. Youth?

REDIRECT EXAMINATION BY MR. YOUTH:

Q **Mr. Rabago, I want to clarify the timelines. So you had mentioned you saw it, and then four days later it went public. So this was filed and finalized -- would you agree that it was filed and finalized on the 18th of October?**

A That's -- that sounds like the right date. I remember when I was -- you told me not to share it, you had wanted to give the Commission first look at it, so I think that might have been like the Friday, and it went public on that Tuesday or something. That's my recollection right now. I could consult my emails, but I think that's what it was.

Q **So if I were to suggest that the press release**

from SEIA that you mentioned might have gone out on October 22nd, that would sync with your recollection?

A Right. That squares with my recollection of the dates.

Q Do you know of any other clients that Crossborder works with?

A Like I say, I know of a couple of reports that were done that were, I believe, funded by Vote Solar, a nonprofit organization that works to advance solar energy. I don't know almost anything else about sort of their resume or their -- their quals.

Q So you're not representing to this Commission that they only do value of solar studies?

A No. I'm only sharing my knowledge.

MR. YOUTH: And Commissioner Finley, I do not have a client list from Crossborder. Would that be something, if I can secure it, if they're willing to share that, that the Commission would be interested in seeing as a late-filed exhibit?

CHAIRMAN FINLEY: I don't need to see that.

MR. YOUTH: Okay.

BY MR. YOUTH:

Q Mr. Rabago, in response to Mr. Patterson's question, I think you may have said all solar is the

same, but you are aware that the Crossborder study differentiates between wholesale solar and smaller scale retail solar; is that correct?

A Yeah. And -- yes. Yes, I am aware that the study does that, and I'm aware that the study breaks those into two categories. That difference falls into the group of areas where we -- we say -- we're asking the question from whose perspective. For example, a customer -- if Commissioner Patterson had a solar system on his roof, the amount he spent for it, whether it was $10.00 or $10 million, would be in -- a point of indifference to the utility if they were just buying the power or he was getting that metering treatment, for example. However, if it's a wholesale facility where you have to procure, you go through an RFP and you procure, you know, contracts for delivery of power, that's a different perspective, and that perspective would include the cost of the facilities, and that's exactly the difference that the Crossborder study cites in its report.

The point, though, that I was trying to make was that the cumulative value of the solar is -- in other words, what effect it has on the grid should be the same, regardless of the nature of the entity that's providing it, right? You do get into locational differences based on the loading of the grid and the marginal local -- the marginal distribution capacity costs that it encounters when it enters the grid and things like that, but by and large, the value should be the same.

Q I think you -- I'm going to go back to Tom Beach for just a second. I think you said you have spoken to him once, maybe?

A I think -- yeah. I'm trying to recall. I know I've talked to him at least once, maybe a couple times, and I know we've exchanged, I don't know, half a dozen, dozen emails or something over time.

Q Would it surprise you to learn that Crossborder Energy has petroleum, BP, as a client?

A I have no basis to be surprised or not. I really -- I really just don't know. I looked at their work in the value of solar area and this work, obviously, and I -- my opinion is based on that.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: All right. Any more questions on Commission's questions?

(No response.)

COMMISSIONER BROWN-BLAND: There being none, I'll entertain motions.

MR. YOUTH: Commissioner Brown-Bland, I would ask that -- wait a second. I think all my exhibits are in, if I'm not mistaken.

MR. HORNE: Well, Commissioner, I'd like to move that the Dominion Rabago -- Rabago Cross Exhibits 1, 2, and 3 be admitted into the record, and I apologize for that.

COMMISSIONER BROWN-BLAND: The name is Rabago.

THE WITNESS: It took me years just to learn to write it.

COMMISSIONER BROWN-BLAND: And the motion is allowed. Dominion's Cross Examination exhibits of this witness 1, 2, and 3 are admitted into evidence.

(Whereupon, Dominion Rabago Cross Examination Exhibits 1, 2 and 3 were admitted into evidence.)

COMMISSIONER BROWN-BLAND: With that, Mr. Rabago, you are excused.

THE WITNESS: Thank you very much.

(Witness excused.)

COMMISSIONER BROWN-BLAND: I think that brings us down to Public Staff.

MR. DODGE: Thank you, Madam Chair. At this time, the Public Staff would like to call witnesses Kennie Ellis and John Robert Hinton to testify as a panel.

COMMISSIONER BROWN-BLAND: All right.

KENNIE D. ELLIS: Being first duly sworn,
Testified as follows:

JOHN ROBERT HINTON: Being first duly sworn,
Testified as follows:

MR. DODGE: Thank you. I'll start with Mr. Ellis.

DIRECT EXAMINATION BY MR. DODGE:

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

A (Mr. Ellis) My name is Kennie Ellis, and my business address is 430 North Salisbury Street in Raleigh, this building.

Q By whom are you employed and in what capacity?

A (Mr. Ellis) I'm employed as an engineer with the Public Staff Electric Division.

Q And did you prefile in this docket direct testimony consisting of 14 pages?

A (Mr. Ellis) I did.

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

A (Mr. Ellis) I do not.

MR. DODGE: Madam Chair, at this time I would move that Mr. Ellis' direct testimony be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: That motion will be allowed, and that is the direct testimony of Kennie D. Ellis, consisting of 14 pages and one appendix, filed September 27th, 2013.

MR. DODGE: Thank you.

(Whereupon, the prefiled direct testimony of Kennie D. Ellis and Appendix A was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

TESTIMONY OF KENNIE D. ELLIS
ON BEHALF OF THE PUBLIC STAFF

September 27, 2013

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

A. My name is Kennie D. Ellis. I am an engineer in the Electric Division of the Public Staff of the North Carolina Utilities Commission. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603.

Q. **WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?**

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

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

A. The purpose of my testimony is to discuss the importance of ensuring that avoided costs are established properly, to provide background on the use of a performance adjustment factor, and to provide the Public Staff's recommendation with respect to an alternative mechanism for the calculation of avoided capacity rates for qualifying facilities (QFs).

Q. FROM A RATEPAYER PERSPECTIVE, WHY IS IT IMPORTANT TO ENSURE THAT AVOIDED COSTS ARE PROPERLY ESTABLISHED?

A. In addition to complying with the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA) and encouraging the development of QFs in the State through appropriate incentives, properly establishing avoided cost rates provides benefits to ratepayers in a variety of ways. These benefits include reducing the risks associated with future increases in the cost of providing electricity and enabling generation to be added to the State's resources in smaller increments so as to avoid the costs associated with the "lumpiness" that results from the addition of large, centralized plants.

To be more specific, under properly established avoided cost rates, QFs can provide positive benefits to ratepayers in the State in the following ways:

- **Pricing.** When a small power producer signs a contract at a fixed price, the potential for changes in operating costs, fuel costs, and capital costs being added to rates is reduced. Since some QFs, such as solar photovoltaic and hydroelectric facilities, are not subject to the risks associated with changes in fossil fuel costs and uncertainty regarding emissions regulations, they can help provide some cost certainty for the utilities in their long-term planning.

- **Construction costs.** Because a QF contract is for power and not for the construction of a plant, ratepayers are spared the risk of cost overruns. Any construction cost overruns are the responsibility of the project developer and will not be added to rate base.

- **Timing.** For many QFs, the lead time of a facility, from planning to commercial operation, is much shorter than the lead time for larger power projects. This is particularly true with solar photovoltaic systems, which can be installed and operational in a matter of months, as opposed to years for larger facilities.

In addition, the small size of most QFs relative to utility-owned generating facilities means that additions to capacity will come in relatively small increments. This helps smooth out the matching of loads and resources and reduce the effects of the "lumpiness" that results from the addition of large central plants for the purpose of meeting smaller, incremental increases in demand over time. For example, in the 2012 IRP filed by Duke Energy Carolinas, LLC (DEC), DEC indicated that it would exceed by more than 3% its target reserve planning margin of 15.5% on three occasions: (1) in 2013-2014 due to the addition of the Buck and Dan River CCs and Cliffside Unit 6, coupled with lower load growth; (2) in 2019 due to the addition of 800 MW of CT capacity to meet its resource needs in 2019, 2020, and 2021; and (3) in 2022, 2024, and 2025 due to the addition of two 1,117 MW nuclear units to meet long-term resource need in 2022 and 2024. (See DEC 2012 IRP, p. 95).

- **System reliability.** Again, due to its relatively small size, the impact of an outage by a QF as compared to a large generating unit on the system is less serious and does not raise the same risk of requiring expensive off-system power. In addition, because of their number and distributed nature, the impact of a loss or one or more QFs would have a smaller impact on system reliability and operations.

- **Compliance with state renewable energy policies.** In establishing a renewable energy portfolio standard (REPS) for the State in S.L. 2007-397, the General Assembly established a clear policy supporting the development of renewable energy resources in the State, including specific requirements, or set-asides, for solar energy and energy derived from swine and poultry waste. By ensuring that avoided cost rates are correct, the Commission plays a vital role in sending appropriate price signals to QFs that may build facilities designed to help comply with the REPS requirements. While the General Assembly established a separate cost recovery method to allow for the utilities to recover their incremental costs of REPS compliance, subject to various cost caps, it did not minimize the need for the avoided costs to be established properly.

A final benefit, of course, is that properly established avoided costs ensure that the QF payments charged to ratepayers do not exceed the utilities' actual avoided costs.

Q. TURNING NOW TO THE PERFORMANCE ADJUSTMENT FACTOR, WOULD YOU PLEASE DESCRIBE IT AND ITS HISTORY?

A. Yes. In the early years of implementation of PURPA, the Commission approved a capacity credit adjustment using a 20% reserve margin. This was subsequently renamed the Performance Adjustment Factor (PAF). The Commission has 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 payments equal to the utility's avoided costs.

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More specifically, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided cost without a PAF would require a QF to operate 100% of the on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled. (See e.g., *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 127, pp. 11-12 (2011).) Using a 1.2 PAF allows QFs to receive payment for the utility's full avoided capacity costs if it operates 83% of the on-peak hours. The Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83% of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. Despite challenges to the PAF from DEC, the Commission has repeatedly reaffirmed the use of a 1.2 PAF in the utilities' avoided capacity cost calculations.

Starting in 1997, the Commission has ordered that a PAF of 2.0 be utilized by both Duke Energy Progress, Inc. (DEP), and DEC in their respective avoided capacity cost calculations for hydroelectric facilities with no storage capability and no other type of generation. The use of a 2.0 PAF requires a QF to operate 50% of the on-peak hours in order to collect the full capacity credit.

The Commission explained the reason for the 2.0 PAF for run-of-river hydro generating facilities in its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 106, the 2006 biennial proceeding (Sub 106 Order), as follows:

> The actual reason for using a 2.0 PAF for run-of-river hydro QFs has been that doing so allows them to receive the full capacity payments to which they are entitled while operating under the constraints created by their stream flows. As the Public Staff witnesses pointed out, using a 2.0 PAF places run-of-river hydro QFs on an equal footing with run-of-river hydro generating facilities included in the rate base of the State's utilities, which are able to cover the full costs of these facilities.

(Sub 106 Order, p. 20)

Also in the 2006 proceeding, the Commission declined to calculate avoided capacity rates using a PAF other than the 1.2 PAF for solar and wind, stating that its reasoning for using a 2.0 PAF for run-of-the-river hydro had no relevance to solar and wind because the utilities did not have any such facilities in their rate bases. On the other hand, the Commission agreed that solar and wind QFs, like run-of-the-river hydro, have no control over their energy source and found that to be a legitimate argument for treating them in the same manner. The Commission ultimately concluded that it should continue its existing practices with the understanding that the parties should further address PAF-related issues in the next biennial avoided cost proceeding. (Sub 106 Order, pp. 21-22) The issue was not litigated during the last two biennial proceedings.

Q. WHAT IS THE PUBLIC STAFF'S POSITION WITH RESPECT TO THE TREATMENT OF SOLAR QFS IN THIS REGARD?

A. In its reply comments in Sub 106, the Public Staff stated that, in addition to considering the appropriateness of using a different PAF for solar QFs, the Commission should consider whether there are other ways by which capacity credits could be spread over fewer on-peak hours. The Public Staff believes that DEC's Option B has some merit in this regard and that the Commission should consider requiring DEP and Virginia Electric & Power Company, d/b/a Dominion North Carolina Power (DNCP) to offer a comparable Option B in addition to their traditionally-calculated avoided capacity rates.

Q. PLEASE DESCRIBE DEC'S OPTION B.

A. In its Initial Statement filed November 1, 2002, in Docket No. E-100, Sub 96, DEC stated that it was proposing the addition of a new rate structure option for its avoided cost rate schedule (Schedule PP), designated as Option B. DEC further stated that the designation of on-peak and off-peak hours in Option B had been modified to align with the periods corresponding to the times when DEC's customer demand and the cost of generation generally is highest. (DEC's

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2002 Initial Statement, p. 20) For this rate option, DEC used the on-peak and off-peak hours set forth in its Schedule OPT rate applicable for service to non-residential customers, which resulted in a reduction in the number of on-peak hours compared to the traditional Schedule PP on-peak hours. DEC stated that this new rate structure would be beneficial to QFs with limited operating hours but with output that is mostly coincident with DEC's peak demands, such as photovoltaic and storage hydroelectric facilities. This new Option B was approved without objection.

In the 2004 biennial proceeding, in Docket No. E-100, Sub 100, DEC again proposed to offer its Option B set of on-peak and off-peak hours, but to eliminate the Option A set of rates. In support, DEC stated that the Option B set of hours is closely aligned with the hours of DEC's system peak demands and that the result is higher per-kWh rates at times when the capability is most needed, which encourages QFs to operate their facilities during these times. (DEC's 2004 Initial Statement, p. 3) DEC further stated that the traditional "Option A" Schedule PP set of on-peak hours spread capacity credits over 4,160 on-peak hours per year. The Option B set of hours spreads those credits over 1,860 on-peak hours per year, which should reduce the need for a higher PAF. (DEC's 2004 Initial Statement, p. 19)

In its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* (Sub 100 Order), the Commission rejected DEC's proposal to eliminate its Option A, but agreed that DEC should be permitted to offer Option B as an additional option to QFs. (Sub 100 Order, p. 48)

In the 2006 proceeding in Docket No. E-100, Sub 106, the Commission scheduled an evidentiary hearing for the purpose of considering issues raised in the parties' initial statements, which included the appropriate PAF for solar QFs. In this regard, DEC filed the rebuttal testimony of Steve W. Smith, the manager at that time of DEC's non-utility generation department. Mr. Smith stated that solar photovoltaic systems have the capability of operating at times when the demand for electricity is higher and therefore DEC did not object to applying a PAF of 1.2 to purchases from solar QFs. However, he opposed the use of a 2.0 or higher PAF. (T. Vol. 1, p. 65) He further stated that DEC believes that the benefits of solar power during peak hours is already recognized and appropriately priced in the Company's Option B rates, which had proven attractive to solar QFs. (T. Vol. 1, p. 66)

Q. IS THIS APPROACH CONSISTENT WITH GUIDANCE PROVIDED BY THE FEDERAL ENERGY REGULATORY COMMISSION (FERC)?

A. Yes. In its Order 69,[1] the FERC stated the following:

> Some technologies such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based in part on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance for some capacity value and an energy component that reflects the avoided energy costs at the time of peak.

Since DEC, DEP, and DNCP are all summer peaking systems, it is appropriate to consider the value of the power provided by generating systems that operate during these times of higher customer demand and to encourage production during periods of time when the value of the electricity is greater to the purchasing utility and to ratepayers.

Q. DO SOLAR PHOTOVOLTAIC SYSTEMS LOCATED IN NORTH CAROLINA GENERATE ELECTRICITY DURING THE SYSTEM PEAK?

A. To an extent, yes. As illustrated in the chart on page 13 of DNCP witness Petrie's prefiled testimony in this proceeding, there is a partial alignment of solar output from facilities located in the State

[1] *Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980).

with utility system one-hour peak loads. In a typical configuration, the output of a solar photovoltaic system will peak earlier than the one-hour system peak load and only a portion of the solar output is available to offset that peak load. However, if a solar QF has the option of receiving a higher capacity credit during specified critical on-peak hours, it could design its facility so that its output is a better match to the system's demand. This type of change can be done by utilizing tracking systems, or adjusting the tilt or azimuth of fixed solar panels to maximize electricity generation during the specified critical on-peak hours.

Q. **WHY IS ALLOWING THIS OPTION BENEFICIAL TO RATEPAYERS?**

A. Under traditional rates, a solar QF is compensated based on a larger number of hours at a lower capacity rate. It, therefore, would likely choose to configure its system to maximize total electricity output during all of the on-peak hours, regardless of the timing of its generation relative to a system's peak load. While this has value in that the utility's load is increasing at the same time as the solar output increases, the solar output would have greater value if it were better matched to the utility's load. If the QF utilizes the Option B approach and configures the system to maximize electricity generation during the specified critical on-peak hours, the electricity purchased by the utility and paid for by ratepayers has greater value.

Q. PLEASE EXPLAIN WHY DNCP SHOULD BE INCLUDED IN YOUR OPTION B RECOMMENDATION.

A. Historically, DNCP has used the differential revenue requirement (DRR) method for calculating its avoided costs, and the Commission has not applied a PAF to DNCP's avoided capacity costs. In its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 59, issued in 1991, the Commission directed DNCP to reexamine its calculation of capacity payments on the basis of 3,120 hours in order to determine if it was consistent with the application of a 20% performance adjustment. The Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 66 (Sub 66 Order), issued in 1993, states that DNCP presented testimony supporting (a) its calculation of capacity payments on the basis of 2730 hours and (b) capacity factors in its models of 71% on peak and 34% off peak, in lieu of a performance adjustment. Based upon the lack of any challenge to the new calculation, the Commission approved it. (Sub 66 Order, p. 26)

In this proceeding, however, DNCP has proposed to establish a new rate schedule, Schedule 19-FP, calculated using the peaker method. As filed by DNCP, the capacity rates for hydroelectric QFs with no storage reflect a PAF of 2.0, and the capacity rates for all other eligible QFs reflect a PAF of 1.2. For this reason, DNCP should be included in the consideration of adding an Option B to DNCP's traditionally-calculated avoided capacity rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

KENNIE D. ELLIS

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Engineering with a concentration in nuclear power.

I began my employment with the Public Staff Electric Division in May of 2003. While with the Electric Division, my primary responsibilities have been fuel factor computation and inventory, generation adequacy, small power and utility generator Certificates of Public Convenience and Necessity, investigation of inquiries and complaints, and management of various tracking databases. I have also worked in the areas of rate analysis and design, revenue analysis and design, nuclear decommissioning, power plant performance, utility service rules and regulations, cost of service, analysis and review of conservation and load management programs, least-cost integrated resource planning, avoided cost, electromagnetic fields, electrical safety, customer growth analysis and validation, unbundling of service, review of wheeling and rates and depreciation analysis.

From October of 1984 until April of 2002, I was employed by Carolina Power & Light Company (Progress Energy Carolinas) primarily at the Shearon Harris Nuclear Power Plant in various capacities including Regulatory Specialist, Operating Experience Coordinator, Corrective Action Program Specialist, Pressure Test Engineer, and Health Physics Technician.

From 1978 until 1984, I was employed by the United States Navy in the Naval Nuclear Power Program. I was an instructor at the Navy's Nuclear Power Program S5G prototype providing instruction in the areas of Chemistry, Radiochemistry, Radiation Protection and Monitoring, Mechanical Systems, Mechanical Watchstanding, and Integrated Plant Operations. I also served aboard the SSBN-644 (USS Lewis & Clark) as Leading Engineering Laboratory Technician. I was qualified Engine Room Supervisor and all subordinate watchstations.

I have previously filed testimony before the Commission in new certificate applications for generating facilities, fuel proceedings, general rate cases, renewable energy portfolio standards recovery proceedings, and participated in several special investigations.

BY MR. DODGE:

Q Mr. Ellis, do you have a summary of your testimony?

A (Mr. Ellis) Yes, I do.

Q Would you please provide that at this time?

A (Mr. Ellis) Yes. My testimony discusses the importance of ensuring avoided costs are properly established, provides background on the establishment of a performance adjustment factor, and provides a recommendation of an alternate mechanism for the calculation of a capacity contribution of the avoided costs similar to that originally proposed in Docket No. E-100, Sub 96, which was approved by the Commission and subsequently used by Duke Energy Carolinas.

The alternate proposal uses a lower number of hours than the traditional on-peak hours over which to spread the annual revenue requirement. This reduced set of hours is more coincident with the utility's peak demands and -- and results in higher per kWh rates at times when the capacity is most needed. This option has also been more attractive to the solar QFs.

This concludes my summary.

Q Thank you. Switching to Mr. Hinton. Mr. Hinton, would you please state your full name and address

for the record?

A (Mr. Hinton) My name is John Robert Hinton. I work at 430 North Salisbury Street, Raleigh, North Carolina.

Q By whom are you employed and in what capacity?

A (Mr. Hinton) I work for the North Carolina Public Staff. I'm Director of Economic Research Division.

Q And did you cause to be prefiled in this docket confidential direct testimony consisting of 34 pages on September 27th, 2013?

A (Mr. Hinton) Yes.

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

A (Mr. Hinton) Yes. I have one change I'd like to make. On page 9, on line 9 of page 9 there's words "carrying charge or fixed charge rate," and I'd like to remove the word "carrying charge or" so it just reads "fixed charge rate."

Q I believe you'd strike the words "carrying charge rate or?"

A (Mr. Hinton) Yeah. Yes. I'm sorry.

Q On page 9, line 9?

A (Mr. Hinton) Correct.

MR. DODGE: Madam Chair, at this time I would move that Mr. Hinton's confidential direct testimony, as corrected today, be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: That motion is allowed, and Mr. Hinton's direct testimony will be received in the record as if given orally from the stand, and I remind that it is a confidential testimony.

(Whereupon, the prefiled direct testimony of John Robert Hinton, as corrected, was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 136

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

September 27, 2013

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

A. My name is John R. Hinton. I am Director of the Economic Research Division of the Public Staff of the North Carolina Utilities Commission. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603. My qualifications and experience are provided in Appendix A.

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

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

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

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

Q. HOW ARE AVOIDED COSTS UTILIZED IN NORTH CAROLINA?

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

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

A. The Commission has long approved the use of the peaker methodology for the purpose of establishing avoided costs. The Commission has held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a combustion turbine, or CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Stated simply, the fuel savings of a baseload unit will offset its higher costs, producing a net cost equal to the capital costs of a peaker. The Commission has held further that a CT is an appropriate proxy for the capacity-related portion of the total costs of a generating unit that might be added to the system in order to increase system capacity. Thus, avoided capacity costs should equal the cost of a hypothetical CT.

Q. PLEASE DISCUSS YOUR REVIEW OF THE COMPANIES' PROPOSED AVOIDED ENERGY COSTS.

A. I began my review by comparing the avoided energy rates proposed by each utility. The proposed avoided energy rates contained in

DEP's Schedule CSP-29 are 14% to 29%[1] lower than the currently approved rates. The amount of decrease varies depending on whether it is for on-peak or off-peak energy and whether it is for a two-year (variable), five-year, ten-year, or 15-year standard contract.

The proposed avoided energy rates contained in DEC's Schedule PP-N are 3% to 14%[2] lower than the currently approved rates. The amount of decrease varies depending on whether it relates to on-peak or off-peak energy and whether it is for a two-year (variable), five-year, ten-year, or a 15-year standard contract.

DNCP proposed reducing its avoided energy rates between 6% and 19%[3]. Similar to DEP and DEC, the amount of decrease varies depending on whether it is for on-peak or off-peak energy and the length of the standard contract.

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

A. All three companies use either the PROMOD or the PROSYM production costing model to estimate their avoided energy costs over the next 15 years. The models provide a chronological estimate of the hourly fuel costs, variable O&M costs, and generation unit start-up costs associated with the production of energy. This estimate is

[1] Public Staff Initial Comments in Docket No. E-100, Sub 136.
[2] Ibid.
[3] Ibid.

performed by replicating the future costs of operating each utility's generating units combined with other supply-side resources, such as its demand side management programs and purchases from other generators. The model dispatches the generating units in a least cost manner subject to various constraints, such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times. The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts and the resource expansion plan from its Integrated Resource Plan (IRP). Multiple iterations of the model are performed that simulate operating conditions associated with possible forced outages.

Each utility performs two model runs: one at full load and one that assumes 100 MW or 150 MW of zero cost power. The difference between the two runs represents the avoided energy costs associated with QF generation.

The avoided energy costs are based upon the marginal cost of the last unit dispatched in the generation stack in each hour combined with adjustments for reductions in working capital and line losses.

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

A. The largest factor was the decrease in the forecast of natural gas prices over the next 15 years. On average, DEP reduced its natural gas prices by approximately 23% and DEC by approximately 26% from the price forecasts in the previous avoided cost proceeding (Docket No. E-100, Sub 127). DNCP reduced its natural gas prices by approximately 17%. The MWH output, heat rates, and other generating unit characteristics were comparable to those assumed in Docket No. E-100, Sub 127. Fuel price forecasts are often the most influential factor on avoided energy costs and can cause significant changes between proceedings. This is largely due to the fact that fuel costs for marginal units often dominate over variable O&M and generation start costs.

Q. DO YOU BELIEVE THAT THE INPUTS USED IN THE CURRENT CALCULATIONS OF AVOIDED ENERGY COSTS ARE REASONABLE?

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

Q. PLEASE DISCUSS YOUR REVIEW OF THE COMPANIES' AVOIDED CAPACITY COSTS.

A. I began my review by comparing the avoided variable, five-year, ten-year, and 15-year capacity rates proposed by each utility. DEP's proposed avoided capacity rates contained in its Schedule CSP-29 are 22% to 27%[4] lower than the currently-approved capacity rates. The amount of decrease varies depending on the time of year and whether it is for a two-year (variable), five-year, ten-year, or 15-year standard contract.

DEC's proposed avoided capacity rates contained in its Schedule PP-N are 28% to 30%[5] lower than the rates currently approved. The amount of decrease varies depending on the time of year and whether it is for a two-year (variable), five-year, ten-year, or 15-year standard contract.

DNCP's proposed avoided capacity rates cannot be easily compared to its 2010 rates because DNCP previously calculated its avoided costs using the differential revenue requirements method.

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[4] Public Staff Initial Comments in Docket No. E-100, Sub 136.
[5] Ibid.

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

A. Unlike the calculation of avoided energy costs, which entail hundreds of inputs, the calculation of avoided capacity costs incorporates considerably fewer inputs and they relate largely to the installed cost of a CT. Each utility's financial carrying cost for the CT, a cost component for fixed O&M, an adjustment for line losses and working capital, and a performance adjustment factor (PAF) are also used.

The most influential assumption is the projected installed cost of the CT per kW, which I will subsequently discuss in depth. The second most influential assumption is the carrying cost rate for the CT. The carrying cost calculation can be rather complex; however, it generally involves the application of factors such as the cost of capital, property and income tax rates, deferred taxes, insurance rates, and the projected inflation rate over the life of the CT. The carrying cost rate includes the cost of depreciation, which is dependent on the assumed useful life of the CT. The third most influential component is the costs of fixed O&M, which includes items such as the costs of major maintenance events, inspections, and system overhauls. The remaining cost components relate to adjustments for avoided working capital and avoided line losses, and the application of the PAF.

Because of the complexity of the calculation of avoided capacity costs, I provide an example below. In addition to demonstrating the process, this example also shows that the projected cost of an installed CT is the predominant factor in the calculation. DEP, DEC, and DNCP do not make the exact same calculations, but the following example generally is applicable to all three of the utilities in this proceeding:

1) Installed Cost per kW	$ 650
2) Carrying charge rate or fixed charge rate	x 10%
3) Annual Carrying Cost	$ 65
4) Fixed O&M per kW	$ 4
Sub Total	$ 69
5) Adjustment for Working Capital	x 1.030
	$ 71.07
6) Adjustment for Line Losses	x 1.02
	$ 72.49
7) Performance Adjustment Factor	x 1.20
8) Annual Avoided Capacity Costs per kW	$ 86.99

The annual avoided cost of $ 86.99 per kW would then be reflected in the proposed capacity rates by spreading the costs over a selected number of on-peak hours.

The importance of the number of on-peak hours used can be illustrated by DEC's Option A and Option B rates. While these rates are significantly different, both sets of rates are designed to recover the very same annual avoided capacity cost, which is $86.99 in the above example.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE PROPOSED INSTALLED COSTS OF A CT USED BY THE UTILITIES?

A. Yes. While I am comfortable with DNCP's projected installed cost of a CT, I have concerns with the projected installed costs used by DEC and DEP. Both DEC and DEP used substantially lower installed costs of a CT in this proceeding than in the 2010 avoided cost proceeding.

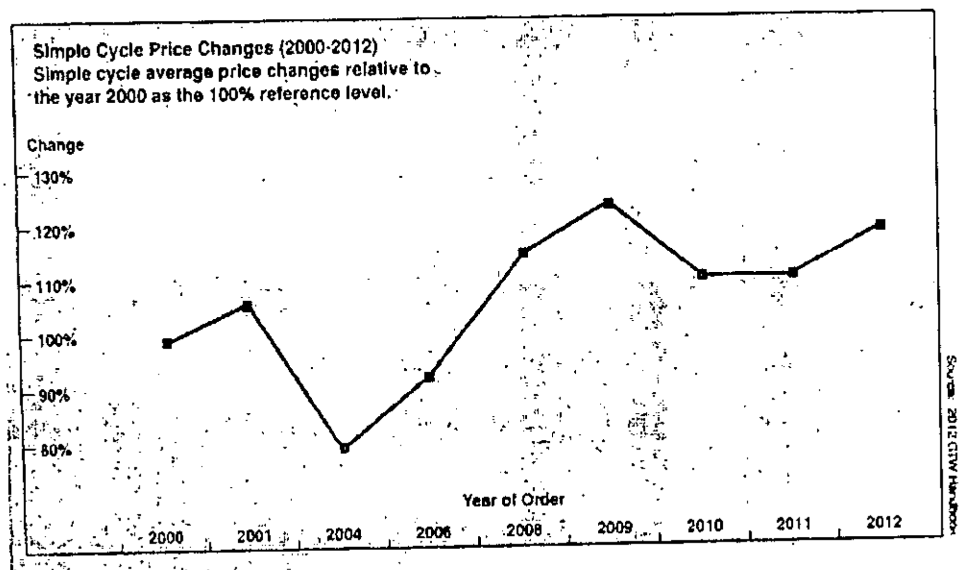
DEC lowered its installed cost of a CT per kW by 23% from the installed cost approved in 2010 proceeding of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In the 2010 avoided cost proceeding, DEC estimated its cost for four-unit CT project with a nominal rating of 816 MW to be **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** as compared to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in this proceeding for a similarly-rated GE frame 7FA.05. This change represents a 24% decrease in the installed cost for the CTs. The reduction in DEC's installed cost per kW is the single most significant issue related to DEC's avoided costs in this proceeding. In fact, the last proceeding in which the Commission approved avoided capacity rates for DEC that were as low as the rates currently proposed by DEC was in the 2006 avoided cost proceeding in Docket No. E-100, Sub 106.

Q. **ARE YOU AWARE OF ANY DECREASES IN THE COST OF EQUIPMENT, MATERIALS, AND LABOR SINCE 2010 THAT WOULD WARRANT SUCH A DRAMATIC DECREASE IN THE INSTALLED COSTS AND THE COST PER KW?**

A. No. As part of my investigation, I reviewed trade publications, producer price indices, and studies of the cost of new entry (CONE) in other jurisdictions. I also engaged in discussions with other utility planners and people knowledgeable about the industry. Based on my review, there is inadequate support for DEC's proposed decrease in the installed cost for a CT.

Once a year, Gas Turbine World (GTW) publishes a Handbook edition that is focused on project planning and the pricing of generation. This publication examines industry price trends for CT and combined cycle (CC) generation plants. Prices in the GTW Handbook are the consensus among project developers, owners and operators, consultants, and some original equipment manufacturers as to what is reasonable for budgeting purposes.

The table from the 2012 GTW Handbook shown below does not support the premise that the cost of turbines has fallen since 2010; rather it shows that the prices for turbine generator sets have increased from 2010 to 2012.



Source: Gas Turbine World, "Gas Turbine World 2012 GTW Handbook," Perquot Publishing, Inc., Vol. 30;36. (July 2012).

In its outlook for 2012, GTW stated that "the level of new gas turbine orders is expected to firm up and reflect an increase in price level of about 5% to 7%, compared with 2011 prices."[6]

Furthermore, the Producer Price Index for Turbines and Turbine Generator Sets, published periodically by the Bureau of Labor

[6] Gas Turbine World, "Gas Turbine World 2012 GTW Handbook," Perquot Publishing, Inc., Vol. 30;34. (July 2012).

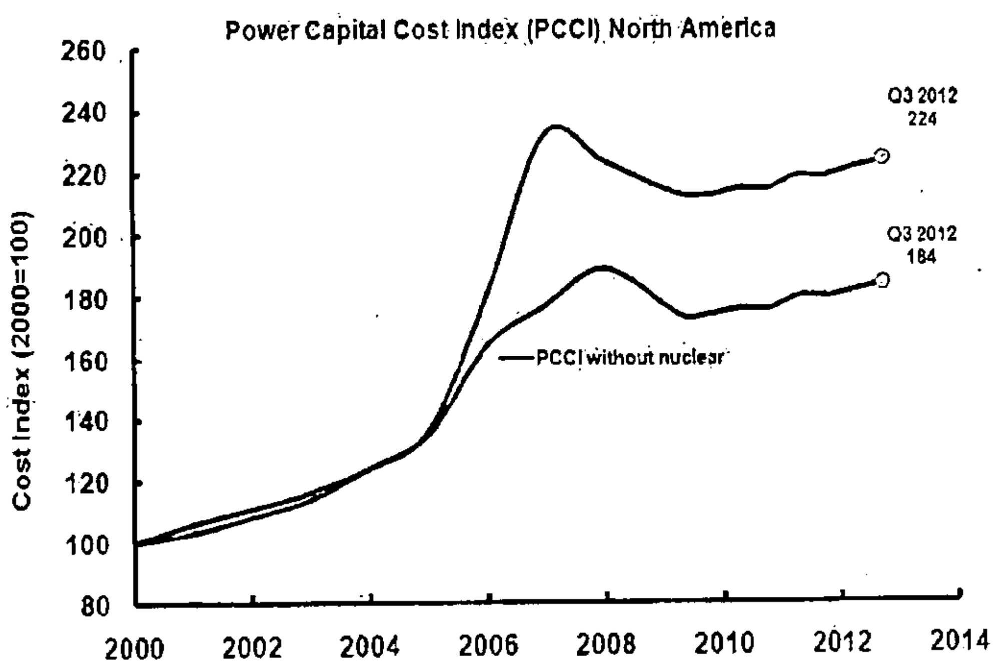
Statistics of the United States Department of Labor indicates that prices have increased 1.2% between November 2010 and November 2012, the time period between the filing of proposed rates in the last avoided cost docket and this one.[7] As such, the cost data on turbines does not support the proposed decrease in the installed costs of a CT.

I have also reviewed the "Duke Energy Carolinas 2012 Generation Reserve Margin Study" prepared by Astrape Consulting (Astrape Study) dated August 17, 2012 that was utilized by DEC in its 2012 IRP, filed with the Commission on September 4, 2012, in Docket No. E-100, Sub 137. Appendix D of this study presents DEC's then current estimate of the cost of a new generic CT. The study incorporated a similar four-unit site of GE 7FA.05 CTs with the same 816-MW nameplate rating as used by DEC in the 2010 avoided cost proceedings. The total project cost identified in the Astrape Study was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is close to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in total project costs for a four-unit site of GE 7FA.05 CTs that was approved in 2010 proceeding. The only differences that I am aware of are that the CTs used by DEC in the 2010 avoided cost proceeding had duel fuel capacity, while the ones used in this proceeding do not, and

[7] Producer Price Index for Turbines and Turbine Generator Sets, United States Department of Labor, Bureau of Labor Statistics (BLS).

the CTs used in the Astrape Study included **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in transmission upgrades, while DEC does not include any in this proceeding.

Lastly, I reviewed IHS CERA Power Capital Cost Index (PCCI), which tracks the construction costs for building coal, gas, solar, wind, and nuclear power plants. Specifically, the index tracks the cost of equipment, facilities, materials, and skilled and unskilled labor. As shown in the chart below, the PCCI does not support the proposed decrease in installation costs as proposed by DEC and DEP in this proceeding.



Source: IHS CERA Power Capital Costs Index (PCCI), September 2012.

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Q. HOW DOES DEC EXPLAIN THE CHANGES FROM THE 2010 AVOIDED COST PROCEEDING?

A. In response to questions from the Public Staff, DEC maintained that a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** worst case contingency factor was included in 2010 and that DEC did not previously employ any economies of scale associated with its plans to build a four-unit site. DEC also said that it learned from the best practices of DEP as to the appropriateness of using a lower contingency cost factor.

Lastly, DEC maintained that it incorporated DEP best practices resulting from the merger, which led to a more rigorous study and better estimates than were relied upon in 2010. If equipment costs have remained flat since 2010, it appears that the decrease in DEC's proposed installed cost per kW is largely due to the adoption of DEP's best practices.

Q. HOW DID DEC'S INSTALLED COSTS COMPARE WITH ITS 2012 IRP?

A. DEC's 2012 IRP incorporated the GE 7FA.05 CTs for a four-unit site with a cost estimate of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]**, which is very close to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** used in the 2010 avoided cost proceeding. Asked why the IRP cost estimates

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are not comparable, DEC explained that the IRP assumed a worst case contingency factor, while the installed CT costs in the IRP did not incorporate economies of scale with a four-unit site, and a less rigorous study was performed. DEC also offered as a partial explanation of the higher installed cost estimates for the CTs in the 2012 IRP the fact that there was a $35 million spreadsheet error and the use of a worst-case contingency factor.

Q. **HAS THE PUBLIC STAFF EVER RECOMMENDED A REDUCTION IN A UTILITY'S PROPOSED AVOIDED CAPACITY COSTS?**

A. Yes. Because of the significant increases in plant construction costs, as testified to by witness Hager in Docket No. E-7, Sub 790, regarding DEC's application for a certificate of public convenience and necessity for Cliffside Unit 6, DEC revised its originally filed estimates for its installed CT cost per kW in the 2006 avoided cost proceeding in Docket No. E-100, Sub 106. DEC's revised cost estimates for the installed cost of a CT at a greenfield site was over 37% higher than originally filed and the installed cost at a brownfield site was 25% higher. The Public Staff informed DEC that it could not support DEC's revised installed costs, but could accept a lower number DEC had calculated that excluded the cost of land, which the Public Staff otherwise believes should be included. This did not constitute a change in position, but rather a willingness to accept a cost estimate that the Public Staff considered to be reasonable and representative of the true cost of pure capacity. In that proceeding, the Public Staff recommended and the Commission approved an installed cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, as compared to an originally filed greenfield estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and an updated greenfield cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Q. **WHAT ARE THE INSTALLED COSTS FILED BY DEC OVER THE LAST 15 YEARS, AND HOW DO THEY COMPARE WITH THE INSTALLED COSTS FILED BY DEP?**

A. For at least 15 years, DEC's proposed installed cost of a CT per kW has been consistently higher than DEP's. The Public Staff raised concerns over DEP's lower estimates in several prior proceedings when DEP relied on the Electric Power Research Institute's (EPRI) Technical Assistance Guide (TAG) reports. This concern was most recently raised during the arbitration proceeding in Docket No. E-2, Sub 966 (*Order on Arbitration* issued January 26, 2011) ("EPCOR arbitration"). The table below provides a comparison of the installed costs used in various avoided cost proceedings:

[BEGIN CONFIDENTIAL]

YEAR	DOCKET	DEP's Installed Cost per kW	DEC's Installed cost per kW	Percent Difference
2010	Docket E-100, Sub 127	[redacted]	[redacted]	[redacted]
2008	Docket E-100, Sub 117	[redacted]	[redacted]	[redacted]
2006	Docket E-100, Sub 106	[redacted]	[redacted]	[redacted]
2004	Docket E-100, Sub 100	[redacted]	[redacted]	[redacted]
2002	Docket E-100, Sub 96	[redacted]	[redacted]	[redacted]
2000	Docket E-100, Sub 87	[redacted]	[redacted]	[redacted]
1998	Docket E-100, Sub 81	[redacted]	[redacted]	[redacted]
1996	Docket E-100, Sub 79	[redacted]	[redacted]	[redacted]
			Average of Differences	[redacted]

[END CONFIDENTIAL]

Q. HAVE YOU ASKED WHY DEP'S INSTALLED COSTS OF CTS IN THESE DOCKETS HAVE TYPICALLY BEEN LOWER THAN DEC'S?

A: Yes. Following the merger between Duke Energy Corporation and Progress Energy, Inc., I was able to inquire about the different approaches taken by the utilities, which has been a question of long-standing interest to me. DEC and DEP noted that economies of scale and scope with a four-unit CT site were a significant factor, since DEC had not previously assumed such economies of scale. There appears to be some inconsistency however, in whether economies of scale were previously utilized by DEC, as indicated in the different responses received by the Public Staff on this matter. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

DEP also explained that, while it includes transmission interconnection costs, it does not generally include transmission system upgrade costs, whereas DEC historically has included both. DEP also utilizes seasonal weighting with the winter rating being used for seven of the 12 months. This increases the assumed kW output because the cooler ambient temperatures during the winter allow for higher output relative to the generation output during the summer months. DEC uses only the summer rating. In addition, DEC's installed costs in the past included a building to house the CT, while DEP's CT cost estimate does not. DEP also noted that it frequently applies a lower contingency factor of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** when estimating the installed cost of CT, whereas DEC has used higher factors, such as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the cost estimations for the Dan River and Buck CC units in Docket No. E-7, Subs 791 and 832, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the 2012 IRP.

Q. **DO YOU AGREE WITH DEC's DECISION TO NO LONGER INCLUDE TRANSMISSION UPGRADE COSTS, SIMILAR TO THE APPROACH TAKEN BY DEP?**

A. Generally, no. A new generation project, particularly one that is over 800 MW, is likely to cause the need for transmission upgrades. In addition, based on the level of transmission costs for interconnection used by DNCP and others in the industry, it appears that DEC and DEP have understated interconnection costs.

While all generators cause interconnection costs to be incurred, transmission, or network, upgrades do not always occur. These vary with the size of the generator and its proposed location. Such upgrade costs are incurred when improvements such as replacing a transformer of installing additional transmission capacity are required. Even when generation is added at an existing plant site with significant infrastructure already in place, as in the case of DEP's new 600 MW Richmond CC facility at its Richmond site, there can be a need for additional transmission capacity and upgrades to accommodate the additional load.[8]

While DEC and DEP both included an estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for electric interconnection costs for an 800 MW CT facility in their proposed avoided capacity rates, they did not include any costs for transmission upgrades. In comparison, DNCP included an "electric interconnect and switchyard" interconnection cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for a 400-MW CT facility. (PS DR DNCP 2-1.) In addition, in the reserve margins studies prepared by Astrape for DEC and DEP, transmission upgrade costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** were included in the capital costs for an 800-MW CT project. (PS DR DEC 4-3.)

In their Reply Comments in this proceeding, DEC and DEP asserted that any transmission upgrades needed to accommodate new CTs would not be avoided because the transmission system is impacted by 200 MW of QFs in much the same way as it is by a 200 MW CT. (Reply Comments, pp. 28-29) However, it seems unlikely that 40 five MW QFs (200 MW total) in multiple locations

[8] *See Order Issuing Certificate of Public Convenience and Necessity* issued on October 13, 2008, in Docket No. E-2, Sub 916, and *Order Issuing Certificate of Environmental Compatibility and Public Convenience and Necessity* issued on October 30, 2008, in Docket No. E-2, Sub 925.

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within a utility's service territory (and often on distribution lines) would require the same level of transmission upgrades as one 200 MW CT facility.

Q. DO YOU AGREE WITH DEC'S AND DEP'S ASSERTIONS REGARDING ECONOMIES OF SCALE?

A. While the Public Staff recognizes the merits of including some economies of scale in the calculation of avoided capacity costs, the Public Staff believes that DEC and DEP have overstated their effect. DEC and DEP witness Pintcke states in his testimony that "cost savings for a four-unit site over single-unit site can be 25% or more just on balance of plant (BOP) costs." (Pintcke T. at 8) Witness Pintcke earlier notes that approximately 40% of the total costs are made up of BOP, while the larger 60% are made up of the Engineer, Procure, and Construct, or EPC costs. (*Id.* at 4). In response to discovery, however, DEC and DEP indicated:

[BEGIN CONFIDENTIAL]

[redacted]

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[redacted]

[END CONFIDENTIAL]

The Public Staff believes that it is more appropriate to use a two-unit site than a four-unit site as a reasonable assumption given the expected annual load growth and the uncertainties inherent in long-range planning. The Public Staff notes that in their 2012 IRPs, DEC, DEP, and DNCP all plan one-, two-, three-, and four-unit sites over varying periods of time during the 15-year planning period. In addition, the likelihood of these CT units being built may also be affected by economic advantages of CC generation as compared to low-capacity-factor CT generation. This been demonstrated by DEC's application to build the previously-discussed Buck and Dan River CCs. In those proceedings, DEC testified that the quantitative results of its least cost model identified the addition of CTs as the least cost option; however, DEC asked the Commission to approve the construction of two 620 MW CCs. The small additional capital investment (less than 0.5% measured by the present value of revenue requirements) to build CCs instead was justified by the significant energy generation and diversity value of CC units. The Public Staff believes that there is a reasonable possibility that this pattern of CCs being selected over CTs in the future will continue even if the quantitative least cost models indicate otherwise. As a result, a two-unit CT facility is a more reasonable assumption.

Q. **DID DEC AND DEP RELY ON AN AVERAGE OF TWO STUDIES IN CALCULATING THEIR INSTALLED COSTS?**

A. Yes, for the most part. Prior to the merger of the parent companies, DEC had requested a study from Sargent & Lundy and DEP had requested one from Burns & McDonnell. The one area in which they did not average the two studies is the contingency factor. Sargent & Lundy included a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent contingency on the total estimate. Burns & McDonnell, however, included a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent contingency factor for project risk. Rather than averaging these contingency factors, DEC and DEP used **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent, which is lower than the contingency factors previously used in avoided cost, IRP, and certificate dockets. In my view, such a contingency factor is more appropriate for a project fairly far down the road in terms of development. It is not appropriate for the calculation of the costs of a hypothetical plant for purposes of the peaker methodology.

Q. IF DEC AND DEP BOTH RELIED GENERALLY ON AN AVERAGE OF THE SAME TWO STUDIES, THEN WHY ARE THEIR INSTALLED COSTS DIFFERENT?

A. DEP and DEC made a number of adjustments to the installed costs that resulted in DEP's estimated installed cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW as compared to DEC's estimated installed costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW. The largest difference, however, is that DEP applied the seasonal weighting that I have already discussed. This reduced DEC's installed cost by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW or approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the total installed cost. The remaining differences are attributable to other utility-specific factors, such as financing costs, return on equity, and other assumptions.

Q. DOES THIS SATISFY YOUR CONCERNS ABOUT THE DIFFERENCES IN THE INSTALLED COSTS OVER TIME?

A. Not entirely. I believe that DEP has consistently demonstrated a tendency to understate the installed cost of a CT. DEP's assumption that large cost reductions can be achieved by economies of scope and scale is consistent with this pattern of understatement.

In February 2012, the National Renewable Energy Laboratory (NREL) published a report titled "Cost and Performance Data for Power Generation Technologies," which was prepared by Black & Veatch.[9] Under the heading "Why Estimates are Not Single Points," the report stated that "typically, when bidders propose on the exact scope at the same location for the same client, their bids vary by on the order of 10% or more."[10] Further, the report stated: "[P]roposing for different clients generally results in increased variability. Utilities, Private Power Producers, State or Federal entities, all can have different requirements that impact costs."[11]

The article discussed many of the issues that have been identified in this proceeding, including land costs, utility interconnection costs, and contingency costs that can range from 5% to 30% depending on the particular point in the cost estimation process and the level of detail and precision in the study. One of the concluding comments of the article is, "It is not possible to estimate costs with

[9] National Renewable Energy Laboratory, "Cost Report: Cost and Performance Data for Power Generation Technologies.", Prepared by Black & Veatch, February 2012.

[10] *Id.* at 7.

[11] *Id.*

as much precision as many think it is possible to do."[12] While the Public Staff agrees with this comment, the Public Staff still has concerns about DEP's record of proposing relatively low installed costs for its CTs.

Q. GIVEN THE VARIATION IN COST ESTIMATES, WHERE ELSE HAVE YOU LOOKED FOR GUIDANCE ON CT INSTALLED COSTS PER KW?

A. As previously noted, I gained insight by contrasting and comparing DEC's, DEP's, and DNCP's estimates. I also gained insight by reviewing the installed costs per kW developed in other jurisdictions, such as the CONE studies used in the development of capacity markets in RTOs.

Q. WHAT ARE DNCP'S INSTALLED COST PER KW?

A. DNCP has projected the installed costs for a 400 MW CT site comprised of two 200 MW GE 7FA CTs at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW without land and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW with land. If these installed costs with land are brought back to 2013 dollars, then this installed cost per kW equates to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW.

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[12] *Id.* at 8.

Q. **DO YOU AGREE WITH DNCP WITNESS PETRIE THAT THE INSTALLED COST OF A CT SHOULD INCLUDE LAND COST ONLY WHEN THE COMPANY PLANS TO BUILD ON A GREENFIELD SITE?**

A. No. The Public Staff has a long-standing position favoring the inclusion of land cost, because the peaker method uses a hypothetical CT and is designed to approximate the cost of a baseload plant. While utilities sometimes add capacity at existing sites, they also build capacity at greenfield sites, such as the Lee Nuclear plant identified in DEC's IRP. In the 2000 biennial avoided cost proceeding in Docket No. E-100, Sub 87, the Commission required both DEP and DNCP to include the cost of land in their calculations of CT costs.

Q. **YOU MENTIONED THE PJM CONE STUDY EARLIER. PLEASE EXPLAIN THIS STUDY AND ITS RESULTS.**

A. On January 31, 2013, in Docket No. ER12-513-000, the FERC approved the use of updated cost of new entry (CONE) values for use within PJM's capacity market. The CONE study is the result of a triennial review of key elements of PJM's Reliability Pricing Market (RPM). The proceeding involves many stakeholders, including utilities, independent power producers, consumer groups, and regulatory Commissions. PJM hired the Brattle Group to

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prepare a study that and provide an estimated gross CONE for each of the PJM zones. The result is an estimate of the total project capital costs and annual fixed O&M expenses for new capacity, for which the Brattle Group used a new GE 7FA.05 CT. Various stakeholders hired consulting engineers and cost analysts to perform studies and filed counter views of the CONE. In reaching a settlement with all parties, PJM agreed to a 3% increase in the cost of a CT from the original cost estimate produced by the Brattle Group study for the Dominion (DOM) zone. The settlement brought the DOM zone estimate to approximately $700 per kW in 2015 dollars, which equates to $666 in 2013 dollars.

Q. **DID YOU REVIEW THE IMPACT ON DEP'S AVOIDED CAPACITY RATES IF DEP HAD REFLECTED ITS RECENTLY APPROVED COST OF CAPITAL IN THE ECONOMIC CARRYING CHARGE RATE?**

A. Yes. I calculated the avoided capacity cost rates that would result if all other assumptions were held constant and the recently approved cost of capital and capital structure approved by the Commission on May 30, 2013, in Docket No. E-2, Sub 1023, were used. The reduction in the cost of capital from 12.75% to 10.2%, along with changes to the capital structure and the cost rates for long-term debt, would further reduce the avoided capacity costs and the resulting rates by an additional 15% from DEP's proposed capacity

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rates. This results in a total decrease of 37% to 42% from the rates approved in the 2010 avoided cost proceeding. In my opinion, this large decrease due the change in the cost of capital underscores the overly conservative assumptions used by DEP in this proceeding.

Q. GIVEN YOUR CONCERNS WITH DEC'S AND DEP'S INSTALLED COSTS, YOUR REVIEW OF DNCP'S ESTIMATE, AND THE RESULTS OF THE PJM PROCEEDING, DO YOU HAVE AN OPINION AS TO THE APPROPRIATE INSTALLED COST PER KW FOR PURPOSES OF CALCULATING AVOIDED CAPACITY COSTS?

A. Yes. Based on my review of the filings, various studies, and discussions with various utility planners, I recommend that a cost estimate of $650 per kW be used in this proceeding. The decline in installed costs urged by DEC and DEP to support the decline in avoided capacity costs seems unwarranted given the installed cost used by DNCP and the costs that can be observed from other industry perspectives. Estimating the cost of a hypothetical CT is not an exact science, but given that there is a convergence of opinion in this range, I believe that cost estimates in the range of $625 to $675 per kW, supported by the correct underlying assumptions, are a reasonable reflection of the true cost of pure capacity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

JOHN R. HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. Since joining the Public Staff in May of 1985, I have filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989 and 1992, I developed the long range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket No. E-7, Sub 620, and Docket No. E-2, Sub 833.. I filed testimony on electricity weather normalization and customer growth in Docket No. E-7, Sub 989. I filed testimony on the appropriate funding for nuclear decommissioning and customer growth in Docket No. E-2, Sub 1023 and Docket No. E-7, Sub 1026. I have filed testimony on the Integrated Resource Plans (IRPs) in Docket No. E-100, Sub 114 and Docket No. E-100, Sub 125. I have reviewed numerous peak demand and energy sales forecasts and the expansion plans filed in electric utilities' annual IRPs. I have filed testimony on the hedging cost of natural gas in electric utility fuel adjustment cases in Docket No. E-2, Sub 1001, Docket No. E-2, Sub 1018, and Docket No. E-2, Sub 1031.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings. I have filed testimony on the avoided cost of electricity in Docket No. E-100, Sub 106, and I have filed a Statement of Position in the

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arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966. I have filed testimony on the issuance of certificates of public convenience and necessity in Docket No. E-2, Sub 669; Docket No. SP-132, Sub 0; Docket No. E-7, Sub 790; and Docket No. E-7, Sub 791.

I have filed testimony on the cost of capital in Docket No. E-22, Sub 333; Docket No. E-22, Sub 412; Docket No. P-100, Sub 133b; Docket No. P-100, Sub 133d (1997 and 2002); Docket No. P-26, Sub 93; Docket No. P-12, Sub 89; Docket No. P-31, Sub 125; Docket No. G-21, Sub 293; Docket No. G-5, Sub 327; Docket No. G-5, Sub 386; Docket No. G-9, Sub 351; Docket No. G-21, Sub 442; Docket No. W-778, Sub 31; and Docket No. W-218, Sub 319. I have filed affidavits on the cost of capital in several smaller water utility rate cases.

I have filed testimony on the expansion of natural gas in Docket No. G-5, Sub 337, and Docket No. G-5, Sub 372. I performed the financial analysis in the two audit reports on Mid South Water Systems, Inc., which were filed in Docket No. W-100, Sub 21. I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency (EPA). I have published an article in the National Regulatory Research Institute's (NRRI's) Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

BY MR. DODGE:

Q And Mr. Hinton, did you prepare a statement of support of the stipulation today?

A (Mr. Hinton) Yes, I did.

Q Would you please provide that statement at this time?

A (Mr. Hinton) Yes. The purpose of my testimony in this proceeding is to make recommendations to the Commission on the Public Staff's position on the appropriate avoided cost rates for Duke Energy Carolinas, Duke Energy Progress, and Virginia Electric & Power Company, and that is Dominion North Carolina Power. These issues were resolved, for the purposes of this proceeding, between the Public Staff, DEC, and DEP in an Agreement and Stipulation of Settlement. In a separate agreement and settle--- stipulation, these issues were resolved between the Public Staff and Dominion North Carolina Power. Both of these stipulations were filed with the Commission on October 29th, 2013.

As part of the stipulation with DEC and DEP, the Public Staff has agreed on an appropriate installed cost on the dollars per KW basis for a CT, combustion turbine, which is the primary cost driver -- or cost component in avoided capacity costs for use in this proceeding. My cost estimate differed from the cost studies commissioned by DEC and DEP. My testimony was based on my review of Dominion North Carolina Power's projected installed costs, the Brattle Report, and Settlement Agreement for the cost of New Entry proceedings filed with FERC, my review of previous filings by both DEC and DEP on the installed cost of the CT and various cost studies by EIA, NREL, and others. The agreement and stipulation would increase DEC's proposed avoided capacity rates by approximately 8 percent and increase DEP's by approximately 14 percent from the proposed rates filed November 1, 2012. The Public Staff believes that this settled CT cost is reasonable as a compromise of the parties' respective positions in the context of the resolution of the issues by the stipulation.

The stipulation with Dominion North Carolina Power recognizes differences in methodology for the calculation and presentation of avoided capacity costs, but confirms the Public Staff's agreement with Dominion North Carolina Power's proposed avoided capacity rates in this proceeding.

The Public Staff asks the Commission to approve the stipulation in its entirety.

This concludes my statement.

MR. DODGE: Thank you. The witnesses are available for cross examination.

COMMISSIONER BROWN-BLAND: Is there cross examination of these witnesses?

MS. FENTRESS: No cross examination from DEC or DEP.

MS. KELLS: We don't have any cross.

COMMISSIONER BROWN-BLAND: All right. Thank you. Mr. Youth?

CROSS EXAMINATION BY MR. YOUTH:

Q **Mr. Ellis, good afternoon.**

A (Mr. Ellis) Good afternoon.

Q **Do you have your testimony in front of you?**

A (Mr. Ellis) I have a copy, yes.

Q **Would you turn to page 3?**

A (Mr. Ellis) I will find it. Trust me.

Q **I may be able to ask you this question without you actually looking at it.**

A (Mr. Ellis) Okay.

Q **I'll come back to page 3, but on pages 2, 3, and 4, carrying over to 5, --**

A (Mr. Ellis) Okay.

Q **-- you describe some of the positive benefits**

to ratepayers that QFs can provide.

A (Mr. Ellis) Yes.

Q Do you remember that?

A (Mr. Ellis) I do.

Q Can you talk briefly, give a summary of the timing benefit with particular focus on solar photovoltaic systems?

A (Mr. Ellis) Yes, I can. These benefits are primarily those quoted by -- from PURPA in one regard and in other dockets, but they -- the timing aspect of this has to do with a smaller -- the QF being able to build a facility in a smaller time frame such that, as my testimony says, a shorter time frame than the larger power plant projects, and it's particularly true with solar. I think we had testimony earlier that development and construction could be done in as little as nine months for a facility as large as five MW.

COMMISSIONER BROWN-BLAND: Mr. Ellis, be sure you speak into the mic.

THE WITNESS: Oh, I'm sorry. I certainly will.

BY MR. YOUTH:

Q And so if I can summarize your answer, I think you said solar PV systems can be built more quickly. Why is that a benefit to ratepayers?

A (Mr. Ellis) Well, it's a benefit to ratepayers because you don't have the carrying cost of the capital for a utility built plant and, really, you have no risk to ratepayers in one regard because of the risk of that capital is all on the -- the developer.

Q And I think you say, this is on page 3, this helps smooth out the matching of loads and resources and reduce the effects of the "lumpiness." Can you describe what the lumpiness means?

A (Mr. Ellis) Yes, I can. Lumpiness in that when you build a large -- when you have a large-capacity addition, you -- you build that when you need that capacity and, therefore, you would build a large plant and then for a small amount of time until you grow into that load, you may be oversized for the capacity that you need. And that's what we refer to as the lumpiness.

Q Well, is there a relationship between lumpiness and a reserve margin?

A (Mr. Ellis) There is, and as you have excess capacity, your reserve margin is obviously larger.

Q So you've got a reserve margin, you've planned for a reserve margin, and then you've got to build out capacity to try to hit that target reserve margin?

A (Mr. Ellis) That's correct.

Q And if you overshoot sometimes because of the size of the facility you build, you have exceeded your target reserve margin; is that correct?

A (Mr. Ellis) That's correct. And by the very nature of a large facility, you have to do that in order to maintain -- you have the adequate reserve margin that you need at all times.

Q And so if you can build distributed generation in smaller increments, 5 MW, that can help you smooth out the lumpiness, as you put it? You can hit that target reserve margin better sometimes?

A (Mr. Ellis) That's correct.

Q Mr. Hinton -- thank you, Mr. Ellis -- I have engaged in a dialogue with you in some of the fuel recovery proceedings this past year about natural gas hedging. Do you recall those conversations?

A (Mr. Hinton) Yes.

Q And is it accurate to say in the Duke Energy Progress proceeding that you testified that Progress' hedging costs in the 2012 test period resulted in ratepayers' bills increasing -- an average ratepayer's bill increasing by about $2.00 a month?

A (Mr. Hinton) Yes. That was in my testimony. The only distinction I'd just like to make clear is, remember, hedging is like in a turned in net cost, which is an accounting calculation because hedging, of course, can be positive and it can be both negative, but for the last four or five years, Progress -- at least four years I can recall, has had a negative net cost, and that's what has gone into rates each year, and last year the system had, I think, a net cost of $77 million.

Q So I get confused when somebody says a negative net cost.

A (Mr. Hinton) Yeah.

Q So I'm going to ask for clarification. The average ratepayer in Duke Energy Progress territory paid $2.00 more per month because of the hedging practices.

A (Mr. Hinton) Yes. Going forward for -- to be recovered over the test year that was approved in that -- or filed in that proceeding, yes. That is correct.

Q Do you have any reason to believe that the additional increment that DEP's average customer pays per month for DEP's natural gas hedging strategy or financial hedging is going to drop to zero in the 2013 test period?

A (Mr. Hinton) No. These costs are borne because they -- the Company entered into these hedging contracts five, seven, eight years previously, and over time, those contracts will be consummated and those costs will be --

will be recorded at the time the contract expires or comes due, so there will be another couple years of large hedging costs that ratepayers will bear -- will bear, most likely, given the current price of natural gas that we currently have and that we will probably have over the next couple years.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: Cross from Ms. Mitchell?

MS. MITCHELL: Yes, ma'am.

CROSS EXAMINATION BY MS. MITCHELL:

Q **Mr. Ellis, Mr. Hinton, Charlotte Mitchell on behalf of the Renewable Energy Group. I have just a few questions for each of you, and I'll start with Mr. Ellis.**

A (Mr. Ellis) Okay.

Q **Mr. Ellis, I want to ask you several questions about capacity factor.**

A (Mr. Ellis) Okay.

Q **And when I refer to Progress, I mean Duke Energy Progress, and when I refer to Duke, I mean Duke Energy Carolinas, just to be clear.**

A (Mr. Ellis) I understand.

Q **Do you know whether Progress' base load capacity factor is less than 83 percent? And you don't**

have to give me a specific number. I'm just looking for a general yes or no.

A (Mr. Ellis) I have a good feel for the capacity factors for the base load generation for all utilities and, in general, they're very similar in that for the nuclears, they're 90, 91, 92; for the coal facilities, the large ones are middle 80s to upper 70s, sometimes lower than that; and the combined cycles that they've been running pretty much full out here lately because of the low natural gas prices, they're in the upper 70s, and sometimes based on performance drops a little lower than that.

But if you'll notice in their base load reports, when you review those, you can see that some of the base load, what they term base load coal, is not being dispatched at its full capacity, so even if it's available to be dispatched, it's not really in the money and it's not being -- you don't have a capacity factor that reflects the unit's ability to be dispatched. But in general, I think that average is going to be right around that 83 percent.

Q **Okay. And would your answer be the same if I were to ask you about Duke's base load capacity?**

A (Mr. Ellis) It would.

Q Is it similar for --

A (Mr. Ellis) Yes, it is.

Q Okay. Do you know whether Progress' system capacity factor is less than 83 percent?

A (Mr. Ellis) I'm sure that it is, but I didn't do the math to calculate that.

Q Okay. And what about Duke's system capacity factor? Is it less than 83 percent?

A (Mr. Ellis) Certainly.

MS. MITCHELL: Okay. Thank you, Mr. Ellis. No further questions for you.

BY MS. MITCHELL:

Q Mr. Hinton, I want to ask you a few questions. My questions are going to focus primarily on the rates that have been proposed by the utilities in this proceeding, specifically the avoided capacity rates. Have you reviewed the avoided capacity rates that Duke proposed in this proceeding?

A (Mr. Hinton) Yes, the original ones, I did.

Q Okay.

A (Mr. Hinton) And my review is largely laid out in my testimony, also, the initial statement that was filed by the Public Staff back on February 7th, 2013.

Q And can you give me an estimate or just a

general percentage of how much those avoided capacity rates have declined from the avoided capacity rates approved by the Commission --

A (Mr. Hinton) Yes.

Q -- in the 2010 proceeding?

MS. FENTRESS: Oh, objection. I believe that this testimony goes to the matter that we have stipulated with REG. Capacity rates are based on CT cost, not entirely, but greatly, and I believe we have waived cross on this topic.

MS. MITCHELL: Commissioner Brown-Bland, my questions are specifically on the rates as opposed to the CT costs or installed cost of the CT, and I was just curious about Mr. Hinton's review of those rates.

MS. FENTRESS: I believe the rates are derived from the CT cost.

COMMISSIONER BROWN-BLAND: To the extent that you're just trying to find out about his review, I'll allow the question, but don't delve too far into that. You know what your settlement agreement is, so stick to it.

BY MS. MITCHELL:

Q In general, have the avoided capacity rates that have been proposed by Duke and Progress in this

proceeding declined from those that were approved by the Commission in 2010?

A (Mr. Hinton) Yes. It's all laid out in my initial statement. I've been doing these for quite some time, and confidentially filed, but yeah, what's noted on page 13 of my report is that Duke's or DEC's rates for the 15-year capacity rate went down 29 percent, and that was under Option A, which is, again, the more traditional rate and the one I usually use as my gauge. But it went down 29 percent and it's on -- and that was for both the on-peak and the off-peak rates.

Q **And you've reviewed the avoided capacity rates proposed by Dominion in this proceeding?**

A (Mr. Hinton) Yes.

Q **And just in general, how did the avoided capacity rates proposed by Dominion compare to those avoided capacity rates proposed by Duke and Progress?**

MS. KELLS: I would make the same comment as Ms. Fentress, just that -- be careful.

COMMISSIONER BROWN-BLAND: I'll allow it -- I'll allow this question, just --

A (Mr. Hinton) Relative to 2010, that's a little hard for me to ascertain. In 2010, they used what they referred to as a DRR method and they did not use "peaker method," so it's not quite the same as an apples to apples comparison as far as what Dominion's rates were in 2010. I can say, because I reviewed the filings, that -- well, I'll stop there.

Q Okay. Just one last question, I think, just to clarify what my previous question was. How did the capacity -- avoided capacity rates proposed by Dominion in this proceeding compare to those proposed by Duke and Progress in this proceeding?

A (Mr. Hinton) Okay. They're higher. It's sometimes hard to compare rates, so in my initial statement, I have a table that looks at the annualized energy rate and the annualized capacity rate and the total avoided cost, and these are based on the rates, the on-peak and off-peak rates, times the number of hours and the rate schedule. It's a convenient way for lay people to see how the rates compare without knowing how -- what your actual operations will be. But if you make the assumptions they'll run on the hours outlined in the tariff, Dominion's FP rate is 6.14 cents, and I estimate that that's the -- let me strike that. The avoided annualized capacity rate is 1.08 cents for Dominion. I calculated that DEC's avoided annualized capacity rate is 0.84 cents. For PEC, I calculated the annualized capacity rates as 0.99 cents.

But to compare all the rates, I would have to go use a composite, but you asked merely about the avoided --

Q **That's correct.**

A (Mr. Hinton) -- capacity.

Q **That's right.**

MS. MITCHELL: And I have no further questions. Thanks, Mr. Hinton.

COMMISSIONER BROWN-BLAND: Ms. Ottenweller?

MS. OTTENWELLER: Thanks.

CROSS EXAMINATION BY MS. OTTENWELLER:

Q **Good afternoon. My questions are based on Mr. Ellis' testimony, but either member of the panel should feel free to respond as you deem appropriate.**

Mr. Ellis, I'd like to start where Mr. Youth left off. He was asking you questions about the benefit to ratepayers that you described from the shorter lead time of many QF projects.

A (Mr. Ellis) Yes.

Q **I want to just ask a couple of specific questions about that to either one of you. On average, what would you say is the lead time from planning to commercial operation for a CT?**

A (Mr. Ellis) It's two and a half years.
Q Okay. And a CC?
A (Mr. Hinton) I'm thinking it's -- it's another year longer, maybe three, three and a half, I've seen.
Q Okay. And what about a nuclear unit?
A (Mr. Ellis) Well, it takes pretty much about 10 years to build one.
Q Okay. Thank you.
A (Mr. Hinton) In their IRP models, it's often eight, nine or 10. It's a long period.
Q Okay. I want to discuss some of the other benefits that you list for ratepayers of entering into QFs. The first benefit you discuss on page 2 of your testimony is pricing. Can you describe how properly priced avoided costs can accomplish this benefit?
A (Mr. Ellis) Well, ideally, if the avoided cost is set appropriately, it should be -- it shouldn't matter whether the utility actually generates the power or they purchase it from the QF. But if you sign a -- if you sign a fixed price contract for a long term that is at the current avoided cost rates, and it's an escalating market, obviously, over the long term you would pay less and that's a benefit to the -- that would be a benefit to the ratepayers for sure.

Q For example, buying energy from QFs can decrease the risk to ratepayers' rising fuel costs?

A (Mr. Ellis) That's true, particularly in an escalating market.

Q Also, the risk of rising environmental compliance costs?

A (Mr. Ellis) Yes.

Q Next you state that QFs can spare ratepayers the risk of construction cost overruns.

A (Mr. Ellis) Certainly. And that's because no ratepayer money is at risk.

Q And these QF contracts provide cost certainty to utilities when they're engaging in long-term planning, right?

A (Mr. Hinton) In the IRP, the utilities often include a couple of contracts with QFs there, but they often -- it's hard to plan for the utilities to plan a lot for these QFs. I know there's -- it changes as, I think, the utility gets more accustomed to the capacity component of the -- of the QF generation, because when utilities plan, they generally plan to meet the peak load and, of course, that's balanced with the energy cost, but nonetheless, often IRPs are based on capacity, so it's the capacity component that the QFs bring to the table that often shapes planning. But the energy component is also incorporated in the models, too, but it's largely driven by capacity.

Q **Thank you. Your testimony also mentions benefits in terms of system reliability, correct?**

A (Mr. Ellis) Yes.

Q **Can you explain those benefits?**

A (Mr. Ellis) Well, the reliability aspects that I was meaning here basically have to do with the small size of the system, and in a smaller system, if it's not available at the time period when it's originally scheduled, then it has less impact on the system, and overall reliability isn't effective as much as a large system.

Q **Okay. Can you turn to page 11 of your testimony? I'm just going to ask you a couple of questions about it. At that page of your testimony, you also discuss the fact that all three utilities in this proceeding are summer peaking systems, right?**

A (Mr. Ellis) That's correct.

Q **And that makes it, as I -- and I'm quoting here, "appropriate to consider the value of the power provided by generating systems that operate during these times of higher customer demand?"**

A (Mr. Ellis) Yes.

Q Your concern here is that the utility's proposed avoided cost calculations may not fully consider the value that solar QFs provide which FERC states, as you quote on page 11, "is greater to the utility than power delivered during off-peak periods"?

A (Mr. Ellis) That's correct.

Q Now, Staff's initial comments in this docket suggested that the Commission could consider the adoption of a PAF of 2.0 for solar QFs to better incorporate this value. Am I interpreting your comments correctly?

A (Mr. Ellis) I think that was the initial comments of the Public Staff.

Q Okay. And your testimony, Mr. Ellis, and the Public Staff settlement with DEC and DEP calls for the adoption of Duke's Option B approach?

A (Mr. Ellis) That's correct.

Q But both approaches are aimed at ensuring that the avoided cost more accurately reflects the cost that the utilities are able to avoid by purchasing from solar QFs during these peak times; is that right?

A (Mr. Ellis) In general, that's what it was targeting, yes.

MS. OTTENWELLER: Okay. No further questions.

Thank you.

COMMISSIONER BROWN-BLAND: All right. Redirect?

MR. DODGE: Just a couple here.

REDIRECT EXAMINATION BY MR. DODGE:

Q On the line of questioning from Ms. Ottenweller just a moment ago, with regard to the Public Staff's support or recommendation that the Commission consider an Option B for the other utilities, it's not to capture any additional costs or benefits necessarily associated with a specific type of resource, but it's to provide an opportunity for QFs to have a better opportunity to earn the energy and capacity to which they're entitled under PURPA?

A (Mr. Ellis) Yes. Option B actually reduces the number of on-peak hours for which the comparison is made, and the Public Staff feels like that it's better for the ratepayers to have an 83 percent availability under those more critical peak hours than a 50 percent availability over the larger scale of all on-peak hours.

Q And at this point, the Public Staff is recommending an Option B approach and not a PAF of 2.0 for solar?

A (Mr. Ellis) That is correct.

MR. DODGE: Thank you.

COMMISSIONER BROWN-BLAND: Questions by Commission? Chairman Finley.

EXAMINATION BY CHAIRMAN FINLEY:

Q **A very serious multiphase question here for you, Mr. Ellis, and I don't think it gets into confidential information. Do you like your peanut butter sandwiches with nutty, smooth, and do you like them with bananas or jelly?**

A (Mr. Ellis) I like them just about any way, to be honest.

Q **How about you, Mr. Hinton?**

A (Mr. Hinton) I'll take bananas any time.

(LAUGHTER.)

COMMISSIONER BROWN-BLAND: Any other questions from the Commission? I have a few for you, Mr. Ellis.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q **With DEC's Option B, would you think it would be a better way to address the hydroelectric facilities that have received a 2.0 PAF, as well as other forms of generation with variability in their fuel source?**

A (Mr. Ellis) Well, the Public Staff hasn't conducted any evaluation or analysis on the -- the hydro QF. We really didn't look at it in this case. It could be an alternative, and probably warrants us looking at it closely maybe at a different time.

Q Do you still believe that assigning PAFs to -- or do you believe that assigning PAFs to various types of QFs other than hydro has merit?

A (Mr. Ellis) I certainly think it can have merit, yes. In this case, the Public Staff has recommended to use Option B for the solar and wind as opposed to going to the different PAF.

A (Mr. Hinton) I would just add to that that having another PAF would require some extensive study and research before we could approach another PAF other than what we traditionally have allowed.

Q Well, you anticipated my next question, which was, you know, how would the Commission go about determining what an individual PAF value should -- what it should be with regard to different forms of generation?

A (Mr. Hinton) A study would have to be done on exactly what impacts, as Ms. Bowman said, would be realized by a large addition of numerous solar generators. They obviously will have benefits, but it's -- it's a complex issue, because they'll have to -- you know, the obvious issue is they'll have to back reduce the generation of several plants and that will cause some inefficiencies, and they'll have to have back standing for when the clouds appear. That will cause some cost. So all of these items put together have to be analyzed over time, and it takes complex modeling and research and study before, I think, a definitive study could be reached. Honestly, there are benefits of solar, as we can readily see in Mr. Rabago's testimony and other testimonies we've seen, but there's some costs, too, and they need to be examined, so a study would need to be in place, in my opinion.

Q Mr. Ellis, do you agree? Do you have any other -- anything else to add?

A (Mr. Ellis) I think Bob's characterization is accurate. I think that we would have to look at it more closely, and some of the elements that would go into that would be the actual performance of these facilities to see some of the -- some of the -- there's a lot of variation that can be done or at least some variation that can be done in a solar facility to optimize or change the output over a spectrum of time and solar radiation. So tracking and azimuth location and the tilt can all be varied to either emphasize the max generation that you get out at one time or a more broad spectrum over a certain time period. So that and oversizing the solar collectors for the inverter size can also provide additional generation over a long period of time. So looking at the -- to really have some good data to compare to see what kind of capacity factors you're really going to get, I think we'd have to have that in order to see to calculate a true PAF.

A (Mr. Hinton) And with that data, then, you can analyze how it does really impact the system as it operates. So both have to be -- it's two part.

Q All right. Now, is it appropriate for ratepayers to pay avoided costs specific to each different QF technology so that the -- that those technologies can have a better chance to receive a full capacity payment? Is that appropriate, in your opinion?

A (Mr. Hinton) Let me ask you to restate that question, please. I believe you asked me is it appropriate for ratepayers to pay specific avoided costs that are -- that are calculated specifically to the generator. Is that the question?

Q Yes.

A (Mr. Hinton) The avoided costs, as said earlier that PURPA defines, are the avoided costs to the utility. Now, if that particular generator, renewable generator, solar or wind, whatever, as noted, provide -- reduces the cost of the utility, then that would be in the definition of PURPA's original intent. And, of course, as Mr. Rabago said, and I looked in the testimonies, the original PURPA has evolved, and so unfortunately I'm not as expert on evolution of PURPA as it's been, but there have been some changes, but the core definition has remained the same, I believe.

Q And so that avoided cost does not change based on the QF technology?

A (Mr. Hinton) Based on how a QF generation impacts the utility. So if solar has got characteristics of providing good energy during the daytime and they have -- they have no price risk and all these things work to lower the cost of the utility, then that -- I think that's within reason.

But, again, the emphasis should be going back to the utility on what the QF, you know, brings to the -- to the table, so to speak.

Q And so would varied and different PAFs for different technologies, would that result in a -- in payments that are additional to avoided cost, and would that be fair or appropriate for ratepayers?

A (Mr. Hinton) It would be -- I think what's appropriate is that the avoided cost would be what -- for ratepayers to only pay the avoided cost, so it would still go back to coming up with what is the appropriate avoided cost. And if we want to take it one step further and say depending on the type of generation, then so be it. And that's, in essence, what I think some of the solar advocates would like to have, is a solar dedicated PAF, and they have one similar to that, I think, in Georgia. But, again, this is a -- for this to occur, you've got to have confidence in the amount of cost reductions on the margin that that are brought by the solar generator or whatever generator.

So, again, we -- you know, in general, when we look at avoided energy cost, like I said in my testimony, it's based on 100 MW of free generation, so there's some averaging that goes on in the calculation of avoided cost, even though it's on a margin. I mean, again, it's a marginal energy contribution at each hour, but even within that there's some -- some averaging goings on.

Q So let me ask, back in 2006, the Public Staff asserted that a distinguishing factor between the hydro and other renewable resources was that at the time, Duke had hydro in its rate base. Given that Duke now has solar in its rate base as well, would the Public Staff --

why wouldn't the Public Staff support a PAF of 2.0 for solar facilities along the same reasoning?

A (Mr. Ellis) Well, we've been advised by counsel that's a legal issue, and we couldn't say any more other than our recommendation at the current time would be that Option B would be a more appropriate step to take.

Q Well, notwithstanding, you reached a compromise agreement in this case, in general, with the reasoning that you applied before as to hydro -- the appropriateness of hydro receiving a 2.0. Why or why not have that same reasoning apply to solar facilities?

A (Mr. Ellis) We're certainly aware that there's a discriminatory issue out there, but we were advised by counsel that's certainly a legal issue and we couldn't -- we couldn't say any more in that regard.

A (Mr. Hinton) I'll just add, without doing research, on the surface if there is merit to what the companies say as far as the amount of hydro that's been added in the last several years -- there has only been three in the last several years -- the amount of solar applications is large, as you well know. The amount of solar that's been put on the system so far is still small, 220 MW or thereabouts, I believe, but the fact that there's so much possible new solar generation that could come onto the system is different than the environment when hydro was contemplated. And, of course, I wasn't here at that time, so -- but I would imagine there is merit to that conversation. But, again, we're not taking a position based solely on that issue, but there may be merit there.

Q **All right. Do you believe that the Commission currently has enough information before it to decide what, if any, changes to make to solar and wind PAFs as well as hydro at this time, or is some other proceeding in order or some other study required?**

A (Mr. Ellis) I personally believe they need additional information in order to make a recommendation as far as a new PAF. Our recommendation was for the Option B and a shorter number of hours to get some of that same benefit.

COMMISSIONER BROWN-BLAND: All right. Any questions on Commission's questions and, in particular, questions about jelly and peanut butter and bread?

(LAUGHTER)

RECROSS EXAMINATION BY MR. YOUTH:

Q **The Public Staff supports and has settled on Option B proposals with all three of the IOUs; is that correct?**

A (Mr. Ellis) That is correct.

Q Has the Public Staff done any sort of calculus to figure out what the Option B is that they've settled on equates to in terms of a PAF? In other words, does the Option B settlement equate to a PAF that's similar between a 1.2 and a 2.0?

A (Mr. Hinton) No. The way the rates are calculated, it's irrespective of the PAF. I mean, what you're doing is you're calculating the annual avoided capacity or energy rates for capacity in this case, and you divide that by the number of hours, and it's either the number of hours specified in Option A or it's the number of hours in Option B, but at the end of the day you're still collecting the same avoided capacity cost, so there's -- there's no -- no difference as far as the cost recovery. Obviously, there's a difference in the hours that the QF is able to collect those capacity payments, and as we said, Option B provides a more attractive schedule that allows -- that should allow them to be able to get their full capacity payment they're entitled to.

So, again, the Option B versus Option A, both rate schedules are designed to collect the same overall annual avoided capacity cost.

Q That's what they're designed for, but in practical effect, a QF that selects A versus B or B versus A is not realizing the same revenue stream; is that correct?

A (Mr. Hinton) Well, it obviously depends on their hours of operation, but yeah, I mean, if they were both operating the exact same number of hours, one would get a different rate than B, probably, than the other, but it's -- it can be different, yes.

Q And I believe you or Mr. Ellis testified or stated in your summary that you believe Option B is usually chosen -- where it currently exists in DEC territory, that's the option that's usually chosen by solar QFs?

A (Mr. Ellis) That was actually in the testimony of Duke Witness Smith back in -- I think it was Docket 96. Yes.

Q So you all would expect a solar QF in Duke territory that selects Option B to realize a greater revenue stream than someone that -- a solar QF that selects Option A?

A (Mr. Hinton) One would expect it because it's -- the hours are more compatible with their generation of power, the daylight, and the peak hours is what we're talking about with capacity, so one might expect that, yes, because the hours are more compatible to the -- their fuel source. So they'll have a higher likelihood of getting their full capacity payment, and that's the appeal that we believe will occur and we recommend that the Commission approve.

Q So is it your understanding that if I'm a solar QF, whether I choose Option A or Option B, I'm getting my full capacity payment either way, even though the revenue stream I'm realizing is different under those two options; or is it the case that it's possible that neither of those options -- under neither of those options I'm realizing my true full capacity payment, but Option B better approximates my full capacity payment than Option A?

A (Mr. Hinton) I would say that both Option A and Option B will allow the QF to get its full capacity payment. I would say Option B, it's going to easier for him to realize his full capacity payment because he'll be able to focus his panels and his system to better accommodate sun. I mean, I guess conceivably, if they run more than 83 percent, they'll get more their -- than their capacity payment. But Option B and Option A will both give them their full capacity payment if they operate during the prescribed hours of the rate schedule.

MR. YOUTH: I've got no further questions.

COMMISSIONER BROWN-BLAND: Additional questions on Commission's questions?

MS. MITCHELL: Yes, ma'am. Just a question for -- either one of you two can answer the question. It doesn't matter.

RECROSS EXAMINATION BY MS. MITCHELL:

Q **What are the hours that are being used by the utilities on the Option B that's been put forth in this proceeding?**

A (Mr. Ellis) In the Stipulation it specifies the hours. Dominion's Option B will be Monday through Friday beginning at 1:00 p.m. and ending at 9:00 p.m. during the summer months, June 1st through September 30th, and beginning at 6:00 a.m. to 1:00 p.m. during the non-summer months for Option B.

Q **And just to be clear, the way that the Option B is designed is the capacity credit is increased during the on-peak -- during the on-peak hours; is that correct?**

A (Mr. Ellis) No. Actually, what happens is the annual revenue requirement is spread over that total number of on-peak hours that we're talking about here, and you calculate a rate based on that time period, therefore, it's the same amount of revenue if you -- if you are at -- if you show up at that time.

Q That's right. And just to be clear, so the Option B provides a smaller range of on-peak hours than the Option A would?

A (Mr. Ellis) That's correct.

Q Okay. And, again, the hours offered under the Option B would be 1:00 p.m. to 9:00 p.m.

A (Mr. Ellis) During the summer months, and that was for Dominion, yes.

Q Okay. And during the non-summer months?

A (Mr. Ellis) During the non-summer months, let's see, 6:00 a.m. to 1:00 p.m.

Q Just one last question. Does the possibility exist that -- and you may have answered this question -- Mr. Youth may have already asked this question -- I'm just going to ask it again -- that a QF generates less revenue under Option B?

A (Mr. Ellis) I'm sorry. Restate that question.

A (Mr. Hinton) You asked does Option B in a QF generate less revenue?

Q Does the possibility exist?

A (Mr. Hinton) I mean, you have to know what --

Q Let me restate - let me restate my question.

A (Mr. Hinton) -- what type of QF, then.

Q **Okay.**

MS. MITCHELL: I'll just withdraw the question.

MR. DODGE: I have one follow-up question on Commission questions, too.

FURTHER REDIRECT EXAMINATION BY MR. DODGE:

Q **Commissioner Brown-Bland asked questions about whether the Commission has enough information to make a determination on use of a PAF and, Mr. Hinton, I believe you indicated that further study may be required, you know, more analysis of this, too, and to some extent the Commission's determination of a PAF, though, is a bit of an equitable approach and not necessarily one that, even in past proceedings, was the result of an extensive study. We're talking about a -- kind of an equitable approach here.**

A (Mr. Hinton) Yes. My review of the development of the PAF over the years showed there was some equitable issues involved. They're not just purely mechanical, so to speak.

MR. DODGE: Okay. No further questions.

COMMISSIONER BROWN-BLAND: Questions on the Commission's questions? All right. Then I believe these witnesses are excused.

(Witnesses excused.)

COMMISSIONER BROWN-BLAND: Before we move into the rebuttal, I'm not sure, Ms. Mitchell, and just out of abundance of caution, did we move and admit the affidavit of Mr. Erik Stuebe? We may have, but I may just have forgotten.

MS. MITCHELL: I don't believe we have, Commissioner Brown-Bland. At this time I'd ask that the affidavit of Erik Stuebe filed on October 18th be moved into evidence.

COMMISSIONER BROWN-BLAND: I believe I had it was filed September 27th. Am I wrong?

MS. MITCHELL: That's correct. I'm sorry. It was September 27th, 2013.

COMMISSIONER BROWN-BLAND: All right. If there's no objection, the affidavit of Erik Stuebe, consisting of three pages, filed September 27th, will be admitted, and under G.S. 62-68 be treated as if given orally from the stand.

(Whereupon, the Affidavit of Erik Stuebe was copied into the record as if given orally from the stand.)

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

FILED
SEP 27 2013
Clerk's Office
N.C. Utilities Commission

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

OFFICIAL COPY

In the Matter of:	)	
	)	
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2012	)	**AFFIDAVIT OF ERIK STUEBE**

The undersigned, Erik Stuebe, having been duly sworn, says as follows:

1. I am a resident of the State of California. I am over the age of 21 and competent to make this Affidavit.

2. I am the founder and President of Ecoplexus Inc., a California corporation. Ecoplexus is a leader in development, design, engineering, construction, and financing of solar power systems, typically in the range of 500 kW to 5 MW in capacity.

3. Ecoplexus has developed forty solar generation systems in the United States—in California, Colorado and Georgia.

4. In my role as President, I oversee Ecoplexus' project finance activities. To date, Ecoplexus has successfully financed solar generation systems with a combination of debt and equity financing.

5. Ecoplexus currently has multiple 5 MW solar qualifying facility ("QFs") under development in Dominion North Carolina Power ("DNCP") service territory (the "Ecoplexus NC Projects"). I have been involved in attempting to secure financing for these projects.

6. Ecoplexus has sought financing for the Ecoplexus NC Projects from two lenders, both of which have financed more than $100 million of solar generation projects. One of the lenders has previously financed Ecoplexus solar generation projects in other states.

7. Both lenders have declined to finance Ecoplexus NC Projects because of Article 6, in DNCP's Agreement for the Sale of Electrical Output to Virginia Electric and Power Company, Schedule 19-FP, which requires a QF to accept payments that are reset at new rate levels or to repay certain sums to DNCP in the event a regulatory body with jurisdiction, such as the Commission or FERC, issues an order that: 1) disallows payments of energy or capacity to non-utility generators; 2) prohibits DNCP from recovering through rates any sums previously paid to non-utility generators; or 3) requires DNCP to repay to ratepayers sums already paid to non-utility generators.

8. Based on my experience in attempting to develop solar QFs in DNCP's service territory, this provision constitutes a barrier to finance.

* * * * *

COMMISSIONER BROWN-BLAND: I believe that takes care of the case on this side of the room to my left, so we're going to move into the rebuttal.

MS. FENTRESS: Yes. Thank you, Madam Chair. We would call up Mr. Snider and Ms. Bowman. We're passing out summaries now.

DIRECT EXAMINATION BY MS. FENTRESS:

Q Ms. Bowman, I believe I'll start with you.

A (Ms. Bowman) Okay.

Q You have previously testified in this proceeding on direct testimony; is that correct?

A (Ms. Bowman) That's correct.

Q And did you also cause to be prefiled in the docket rebuttal testimony consisting of 22 pages?

A (Ms. Bowman) I did.

Q And do you have any changes to make to that rebuttal testimony at this time?

A (Ms. Bowman) I do not.

Q And if you were asked the same questions today at this hearing, would your answers be the same?

A (Ms. Bowman) Yes.

MS. FENTRESS: I would request that Ms. Bowman's rebuttal testimony be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: That motion will be allowed, and the rebuttal testimony of Kendal C. Bowman will be admitted into evidence as if given orally from the stand.

MS. FENTRESS: Thank you.

(Whereupon, the public version of the prefiled rebuttal testimony of Kendal C. Bowman was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012	))))	REBUTTAL TESTIMONY OF KENDAL C. BOWMAN ON BEHALF OF DUKE ENERGY CAROLINAS, INC., AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of the Utilities.

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

A. The purpose of my rebuttal testimony is to address issues raised by other parties pertaining to the avoided cost rates for solar and wind Qualifying Facilities ("QFs") and the Utilities' standard QF contracts. Specifically, I will address the recommendation of Public Staff witness Kennie D. Ellis that DEP adopt an avoided rate schedule that is more similar to DEC's Option B avoided rate schedule (Schedule PP). I will also address arguments made by North Carolina Sustainable Energy Association ("NCSEA") witness Karl R. Rabago and Renewable Energy Group ("REG") witness Don C. Reading that the Performance Adjustment Factor ("PAF") for the avoided capacity rates paid to wind and solar QFs should be increased from 1.2 to 2.0. Finally, I will address the positions asserted by REG witness John E.P. Morrison pertaining to: 1) the purpose of the public Utility Regulatory Policy Act of 1978 ("PURPA") and related state policies, and 2) certain terms in DEC's and DEP's standard QF contracts.

Q. PLEASE SUMMARIZE THE CONCLUSIONS THAT YOU MAKE IN YOUR TESTIMONY IN THIS PROCEEDING.

A. With regard to Public Staff witness Ellis' recommendation, DEP's avoided cost rate schedule is already consistent with DEC's Option B and it does not need to be made more similar. Specifically, DEP's avoided cost rate schedule and its non-residential time of use ("TOU") rate schedules use the same definition of on-peak hours as DEP's current time-of-use rate schedules, just as DEC's Option B and its non-residential TOU rate schedule share a common definition of on-peak hours.

As to the various arguments presented to increase the PAF for solar and wind QFs, the Utilities continue to believe that such an increase in the PAF violates the underlying principles of PURPA and would unfairly provide a windfall for solar and wind QFs at the expense of the Utilities' customers. Furthermore, with regard to NCSEA witness Rabogo's discussion of "value of solar" ("VOS") studies, the Utilities maintain that 1) such studies are not an appropriate means of establishing avoided costs, 2) that witness Rabago's generic discussion of VOS studies is not probative of any relevant issue in this proceeding, and 3) witness Rabago's general statements regarding VOS studies do not justify his recommendation that avoided capacity rates for solar QFs be increase by 67%.

As to REG witnesses Morrison's testimony, the Utilities believe he misinterprets PURPA by understating the importance of ensuring that utility customers are not disadvantaged by paying more than the utility's avoided costs. With regard to witness Morrison's comments regarding the Reduction-in-Energy Charge in DEP's standard terms and conditions, this provision is a fair and reasonable mechanism for protecting DEP and its customers from overpaying QFs under a levelized rate power purchase agreement ("PPA"). As to Section 2 of DEC's standard terms and conditions, DEC has already committed to revise that section to address the issue raised by witness Morrison.

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

A. Not at this time.

I. RESPONSE TO PUBLIC STAFF WITNESS ELLIS' RECOMMENDATION THAT DEP REVISE ITS AVOIDED COST RATE SCHEDULE TO MAKE IT MORE SIMILAR TO DEC'S OPTION B

Q. **PLEASE DESCRIBE DEC'S AVOIDED COST RATE OPTION B.**

A. DEC currently has two different avoided cost rate schedules, commonly referred to as Option A and Option B. DEC's Option A and Option B have different rate structures but are based on the same avoided cost calculations. The primary difference between Option A and Option B is their respective definitions of on-peak hours. Option A applies a broader definition of on-peak hours that includes 4,160 hours. Option B applies a narrower definition of on-peak hours, which encompasses only 1,860 hours.. As a result of this difference, the avoided capacity rates under Option B are higher than the avoided capacity rates under Option A because DEC's avoided capacity costs are being recovered over fewer hours under the Option B rate. Thus, a QF electing DEC's Option B has to run fewer hours to maximize the amount of avoided capacity payments its receives. Conversely, failing to run during a peak hour has a greater adverse impact on a QF under Option B than it does under Option A.

Q. HOW DOES DEP'S AVOIDED COST RATE (SCHEDULE CSP) COMPARE TO DEC'S OPTION B?

A. Unlike DEC, DEP only has a single avoided cost rate structure. Conceptually, DEP's current avoided cost rate schedule is equivalent to DEC's Option B. Like DEC's Option B, DEP's avoided cost rates uses a definition of on-peak hours that is based on the on-peak hours reflected in DEP's non-residential TOU rate schedules (Schedules LGS-TOU and SGS-TOU). Thus, DEP's avoided cost rates and DEC's Option B both use a TOU-based definition of on-peak hours to focus avoided capacity rate payments on the times when the need for capacity is highest. This is the best measure of when power purchased from a QF provides meaningful capacity value.

Although DEP's avoided cost rates and DEC's Option B share a common conceptual basis, they are not identical. The definition of on-peak hours applied in DEP's non-residential TOU rate schedule and its avoided cost rate schedule is more expansive than the on-peak hours definition reflected in DEC's non-residential TOU rates and in DEC's Option B. Accordingly, DEP's avoided rate schedule (and its non-residential TOU rates) uses a definition of on-peak hours that encompasses 3,132 hours, as opposed to the 1,860 on-peak hours reflected in DEC's Option B (and DEC's non-residential TOU rate schedules).

Q. **HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS ELLIS' RECOMMENDATION THAT DEP ADOPT DEC'S OPTION B?**

A. Given that DEP's avoided cost rates are conceptually comparable to DEC's Option B, it is unnecessary for DEP to amend its avoided cost rate schedule as proposed by Public Staff witness Ellis. Although DEP's avoided cost rate schedule uses a broader definition of on-peak hours than DEC's Option B, both of these rate schedules apply on-peak hour definitions based on each respective Utility's TOU rates.

DEP is also currently assessing the design of its TOU rates. In its most recent rate case, DEP committed to review its TOU rates and propose new TOU schedules within two years.[1] After this assessment is complete, DEP intends to continue its practice of using a consistent definition on-peak hours for its TOU rates and its avoided cost rates. It is possible, although not certain, that such assessment will result in DEP proposing changes to its TOU rates, including a redefinition of on-peak hours that is more similar to the definition reflected in DEC's Option B. In any event, these assessments should be completed before any premature changes are made.

As a practical matter, DEP would find it difficult to immediately adopt a significant change in the definition of on-peak hours before the assessment of DEP's TOU rates is completed. This is due to the need for a change in the

[1] See Section 5.B.3 of the *Agreement and Stipulation of Settlement*, as filed on February 28, 2013, in Docket No. E-2, Sub 1023, DEP's 2013 general rate case proceeding. DEP agreed in this provision of the Stipulation to complete a study of its TOU hours for all customer classes within two years from the date of the Commission's General Rate Case Order or by the date that DEP files its next general rate case, whichever comes first.

metering for small QFs to accommodate such a change. Consequently, it would be problematic for DEP to implement Public Staff witness Ellis' recommendation before it is made moot by DEP's reassessment of its TOU rates.

II. <u>THE PAF FOR SOLAR AND WIND QFS SHOULD NOT BE INCREASED FROM 1.2 TO 2.0</u>

Q. WHAT IS YOUR UNDERSTANDING OF THE PAF AND HOW IT WORKS?

A. The PAF is simply a multiplier applied to avoided cost capacity rates to increase the rates paid to QFs. For example, if the PAF is 1.2, then the avoided capacity rates would be the rate approved by the Commission based on the utility's actual avoided cost of capacity multiplied by 1.2. Thus, a PAF of 1.2 increases avoided capacity rates by 20%. Currently, the PAF is 2.0 for the avoided capacity rates paid small hydroelectric QFs and 1.2 for all other QFs.

Initially, the Commission established a PAF of 1.2 for all QFs because QFs, like all types of generation are not capable of running 100% of the time. A PAF of 1.2 allowed a QF to receive a full amount of capacity payments even if it only operates during 83% of on-peak hours. In other words, a 2 MW QF would receive capacity payments equivalent to 2 MW of avoided capacity costs even if it fails to run during 17% of the utility's peak period. In 1997, the Commission increased the PAF solely for small run-of-the-river hydroelectric QFs to 2.0. In so doing, the Commission noted that there was a specific State policy in favor of encouraging the continued operation of such facilities. Given the significant increase in applications for QF licenses, there is no policy justification for artificially high payments, which increase the costs to consumers and are inconsistent with PURPA guidelines.

Q. WHAT IS YOUR UNDERSTANDING OF RECOMMENDATIONS THAT ARE BEING MADE IN THIS PROCEEDING RELATED TO THE PAF?

A. REG witness Reading recommends that the PAF for solar and wind QFs should be increased to 2.0. NCSEA witness Rabago also recommends a PAF of 2.0 for solar QFs, but does not address the PAF for wind QFs.

Q. DO THE UTILITIES SUPPORT INCREASING THE PAF FOR SOLAR AND WIND QFS TO 2.0?

A. No. The Commission should reject the proposed increase in the PAF for solar and wind QFs, which would effectively increase avoided capacity rates paid to such QFs by 67%. As previously explained by the Utilities in this proceeding, there are many reasons for this position:

1. Increasing the capacity rates to certain QFs to compensate for their inability to operate reliably and consistently during peak periods is illogical and violates the avoided cost principles of PURPA;

2: Providing such an enormous additional subsidy to solar and wind QFs under the guise of "avoided costs" is inconsistent with Senate Bill 3, in which the General Assembly established a specific framework for encouraging the development of such solar and wind generation, including limits on the costs that consumers must pay to achieve that goal;

3. This additional subsidy is not needed to encourage the development of solar and wind QFs given the tremendous influx of proposed solar and wind projects that has occurred over the past year; and

4 Increasing the PAF for solar and wind QFs would impose an unnecessary and unjustified economic burden of millions of dollars on the Utilities' customers.

Q. HOW DO YOU RESPOND TO REG WITNESS READING'S ARGUMENTS THAT THE PAF FOR SOLAR AND WIND QFS SHOULD BE INCREASED TO 2.0?

A. REG witness Reading's arguments are merely a summary repetition of the arguments made by REG and NCSEA in their comments filed previously in this proceeding. Those arguments are fully addressed and rebutted in the Utilities' Joint Reply Comments and direct testimony that the Utilities have submitted in this docket.[2]

[2] *See* Utilities Joint Reply Comments at pp. 33-40; Bowman Direct Testimony at pp. 16-21; and Snider Direct Testimony at pp. 44-55.

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Q. HOW DO YOU RESPOND TO NCSEA WITNESS RABAGO'S ARGUMENTS THAT THE PAF FOR SOLAR QFS SHOULD BE INCREASED TO 2.0?

A. NCSEA witness Rabago bases his recommendation on the theory that a VOS study would show that solar generation provides more "value" than is reflected in traditional avoided cost calculations. Witness Rabago suggests that the Commission should require the Utilities to pay solar QFs more than their avoided costs and that a convenient way to do that is to increase the avoided capacity payments to solar QFs by 67% by increasing the PAF for solar QFs to 2.0. There are numerous flaws in witness Rabago's arguments and conclusions. First and foremost, the VOS studies that he describes are inappropriate for setting avoided cost rates and are irrelevant to the present proceeding.

As described by witness Rabago, a VOS study attempts to measure the value of solar generation by quantifying a wide range of alleged, indirect benefits of such generation. These benefits go far beyond the cost of energy and capacity that solar generation displaces. Witness Rabago states that a VOS study would capture and quantify such alleged benefits as: 1) broad environmental benefits for society; 2) job creation; 3) reduced health risks; and even 4) reputational benefits for customers who install solar generation. (Rabago Direct at 8-9) Clearly, such factors are not appropriate in the context of an avoided cost proceeding.

Although QF rates under PURPA are often described with the short hand label of "avoided cost rates," PURPA makes clear that it really means costs and that no rate paid to a QF shall "exceed the cost to the [purchasing utility] of alternative electric energy."[3] Thus, factors such as customer's reputations or job creation are outside the scope of what is permitted under PURPA. Thus, the Commission has held that such factors "cannot properly be included in calculating avoided cost rates."[4]

Witness Rabago has effectively conceded that a VOS goes beyond what is appropriate for consideration in the context of avoided costs. He concedes that PURPA is not "designed … to fully address all of the issues" encompassed by a VOS study. (Rabago Direct at 15-16) By making such a concession, witness Rabago also concedes that the considerations encompassed by a VOS study are beyond the scope of the Commission's authority to set avoided cost rates. Ordinarily, the Commission cannot set rates for wholesale power transactions because that authority is reserved exclusively to the federal government under the Federal Power Act. However, PURPA delegates to the states limited authority to set rates for a particular type of wholesale power transaction (i.e., rates for purchases of power by utilities from QFs). Because the Commission derives this specific ratemaking authority from PURPA, its decisions are subject to the limits

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[3] *See* 16 USCS § 824a-3(d).
[4] *In the Matter of Biennial Determination of Avoided Cost rates for Electric Utility Purchases from Qualifying Facilities*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 106 at 8, 23-24 (Dec. 19, 2007) (ruling that externalities such as general environmental costs are not appropriate for avoided costs).

established by PURPA. Thus, when witness Rabago correctly concedes that his approach to setting "avoided costs" for solar facilities goes beyond the boundaries of PURPA, he is admitting that it also extends beyond the Commission's authority to set avoided cost rates and, thus, beyond the scope of this docket.

Q. ARE THERE OTHER FLAWS IN NCSEA WITNESS RABAGO'S ARGUMENTS AND CONCLUSIONS?

A. Yes, there are several. First, even if VOS studies for the Utilities' systems were appropriate bases for establishing avoided cost rates – which they are not – witness Rabago has not provided any such study for the Commission to consider. To the contrary, he admits that he does not rely upon any such study and does not know if any such study even exists. (Rabago Direct at 11-12) His conjecture regarding alleged benefits of solar generation is not a sound basis for setting avoided cost rates.

Second, again putting aside the inapplicability of VOS studies for avoided cost rate purposes, there is no basis to assume that such a study would produce any quantifiable results. Alleged benefits, such as improvement in customer reputation and reduction in occupational health costs, are difficult to quantify and even more difficult to quantify accurately. For other alleged benefits, it is questionable whether they can even be shown to exist. For example, the assertion that intermittent low capacity factor resources such as solar can improve overall system reliability is at best debatable. Moreover, witness Rabago's approach to assessing solar generation appears heavily skewed toward identifying its benefits and insufficiently concerned with considering its costs. Issues such as the potential impact on spinning reserve and operating reserve requirements of adding a substantial amount of intermittent generation to a utility system are not discussed at all by witness Rabago. Thus, whatever value a VOS study might have, unless it is actually conducted in an even-handed manner, assumptions regarding the results of such a study are unsupported suppositions.

Third, witness Rabago's hypothetical discussion of VOS studies does not support his recommendation to increase the PAF for solar QFs to 2.0. In fact, he fails to establish a quantitative or even conceptual nexus between his discussion and his recommendation. There is simply no way to reach the conclusion that the avoided capacity rates for solar QFs should be increased by 67% from witness Rabago's general discussion of VOS studies.

III. RESPONSE TO THE TESTIMONY AND RECOMMENDATIONS OF REG WITNESS MORRISON

Q. DO YOU AGREE WITH REG WITNESS MORRISON'S STATEMENTS REGARDING THE PURPOSE OF PURPA?

A. Not entirely. Witness Morrison suggests that a goal of PURPA is to ensure that QFs are paid as much as possible to spur their development. That is a one-sided and incomplete description of PURPA. Witness Morrison is correct that PURPA was enacted to encourage the development of small non-utility generation that would help reduce the country's dependence on fossil fuels.

However, PURPA also is clear that pursuit of this policy objective shall not result in higher rates to electric customers.

While it is true that PURPA was not designed to deliver cost savings, it is equally true that PURPA requires that avoided cost rates paid to QFs must be "just and reasonable to customers of the [purchasing utility]."[5] To that end, PURPA strictly prohibits avoided cost rates for QFs that exceed a utility's cost of obtaining electric energy from another source.[6] Thus, although witness Morrison accurately quotes the United States Supreme Court's decision in *American Paper Institute*[7], the Supreme Court's approval of using the "maximum rate authorized by Congress" to provide the "maximum incentive" for QF development must be understood in light of how Congress established that maximum rate. In the case of PURPA, Congress defined the maximum rate with the clear intent of ensuring that the effort to encourage QF development did not impose higher cost for electricity on utility ratepayers.

Q. HOW DO YOU RESPOND TO REG WITNESS MORRISON'S SUGGESTION THAT THE UTILITIES PROPOSED AVOIDED COST RATES MUST BE INCREASED TO ENSURE THE CONTINUED DEVELOPMENT OF QFS IN NORTH CAROLINA?

A. Generally, REG witness Morrison's arguments appear to be influenced by his particular perspective of PURPA. The purpose of the present proceeding is to

[5] 18 C.F.R. 292.304(a)(1)(i) (requiring avoided cost rates paid to QFs to be "just and reasonable to the electric consumer of the electric utility and in the public interest").
[6] *State ex rel. Util's Comm'n v. North Carolina Power*, 338 N.C. 412, 418 (N.C. 1994) (recognizing that "states cannot impose purchase rates in excess of avoided costs").
[7] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 417 (U.S. 1983).

establish rates to be paid for power produced by QFs based on the individual utility's cost of alternative power (i.e., the utility's avoided costs). The goal is not to establish rates that ensure the profitability of QFs. Over time, a utility's avoided costs fluctuate based on a number of variables. Accordingly, there will be periods during which full avoided cost rates are highly favorable to QFs and periods when they are not. However, Congress made it abundantly clear that, under PURPA, no rate may be paid to a QF that exceeds the purchasing utility's avoided costs, even if the rate is not financially attractive to all types of QFs and QF developers.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF REG WITNESS MORRISON THAT ADOPTING THE UTILITIES' PROPOSED AVOIDED COST RATES WILL CAUSE MANY QF DEVELOPERS TO CEASE DOING BUSINESS IN NORTH CAROLINA?

A. In the final analysis, that issue is simply not relevant to this proceeding. The objective is to set rates at avoided costs – not to set rates at levels needed to attract QFs. Furthermore, it is not clear that Mr. Morrison's concerns are well-founded.

Witness Morrison suggests that a decrease of 20% in avoided cost rates will cause QFs to become financially infeasible. (Morrison Direct at 10) However, since the Utilities filed revised avoided cost rates on November 1, 2012, it has been publicly known that a sharp decrease in natural gas prices since 2010 would cause a substantial decrease in the Utilities' avoided energy rates (the larger component of avoided cost payments to QFs). Specifically, DEC and DEP propose decreases in their respective avoided energy rates of up to 29% and 14%, while Dominion North Carolina Power proposes a decrease of up to 19%. Those decreases are essentially unchallenged in this proceeding.

Despite this imminent decline in avoided cost rates, solar development (and investor interest) in North Carolina has trended sharply upwards in the past year. Certificate applications with the Commission have increased exponentially in 2013. A recent September 2013 analysis of North American Solar PV Markets forecasted installed solar PV in North Carolina to increase by 80% in Fiscal Year 2013 (second only to California). By contrast, solar PV across the United States would increase only by 17% year over year.[8] Thus, QF development in the State does not appear to have been slowed by the anticipated decrease in the Utilities' avoided cost rates. Further, in a recent March 23, 2013, News & Observer article, Mr. Morrison commented on the current state of the North Carolina solar PV market suggesting that solar PV was six times more expensive in 2007 when Senate Bill 3 was passed than today.[9] As QFs are not obligated to make their financial information public, it is difficult to assess the accuracy of witness Morrison's description of the economics of QF projects. However, his dire predictions regarding the impact of a 20% decrease in avoided cost rates seem at least questionable in light of such a precipitous drop in solar PV install costs.

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[8] See http://www.solarbuzz.com/news/recent-findings/california-sets-quarterly-record-solar-pv-q213-us-adds-976-mw-according-npd-so

[9] http://www.newsobserver.com/2013/03/23/2772040/possible-tax-credit-repeal-could.html (Published March 23, 2013).

Q. WHAT IS YOUR UNDERSTANDING OF WITNESS MORRISON'S ARGUMENTS REGARDING THE TERMS AND CONDITIONS IN DEC'S AND DEP'S STANDARD QF CONTRACTS?

A. REG witness Morrison has raised concerns relating to one provision in DEC's standard QF contract and one provision in DEP's standard QF contract. The provision in question form the DEC is Section 2 and the provision of the DEP standard QF contract is Section 6.

Q. WHAT IS YOUR RESPONSE TO REG WITNESS MORRISON'S ARGUMENTS REGARDING SECTION 2 OF DEC'S STANDARD QF CONTRACTS?

A. REG witness Morrison notes that certain language that had been included in previous versions of Section 2 of DEC's standard QF contract has been omitted in the version filed in this proceeding. The language in question pertains to the effect of changes made by the Commission to DEC's rate schedules and service regulations. Section 2 of DEC's Terms and Conditions provides that those rate schedules and service regulations are subject to change by the Commission and any such changes "shall immediately be made a part [of the QF contract], and shall nullify any prior provision in conflict therewith." Previously, DEC's Terms and Conditions also included language that limited the reference to changes in rate schedules to "variable rates only."

REG witness Morrison questions the omission of the foregoing language because it suggests that DEC intends for long-term fixed rates to be subject to change by subsequent Commission action. That was not DEC's intent and

DEC agrees that once a QF signs a long-term fixed rate contract, the QF is entitled to those rates for the life of the contract. However, the previous language in Section 2 was over-broad and appeared to suggest that even non-rate terms and provisions in long-term fixed rate contracts were immune from Commission-authorized changes. In light of the comments filed by the Public Staff and REG, DEC proposed in the Utilities' Joint Reply Comments to amend Section 2 of its Terms and Conditions to include the following language:

> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all other provisions of the Rate Schedules and Service Regulations, including but not limited to Variable Rates, other types of charges (e.g., facilities charges), and all non-rate provisions.

DEC believes that the foregoing language addresses the concerns raised by REG witness Morrison.

Q. WHAT IS YOUR RESPONSE TO REG WITNESS MORRISON'S ARGUMENTS REGARDING SECTION 6 OF DEP'S STANDARD QF CONTRACTS?

A. Witness Morrison is arguing that DEP should be required eliminate the provision of Section 6 of DEP's standard QF contract referred to as the Reduction-in-Contract-Energy-Charge. This provision provides for a modification of the amounts paid to a QF in the event that the QF fails to provide the amount of energy called for in the contract. Specifically, the Reduction-in-Contract-Energy-Charge provides, in pertinent part:

After the first two years of operation of the Facility, if Seller's average energy generated in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak Energy level, the Company may invoke a Reduction-in-Contract-Energy-Charge and establish a new Contract Energy level for on-peak and off-peak energy periods, respectively.

The Reduction-in-Contract-Energy-Charge is calculated as the total amount the QF has been paid for Energy Credits less: 1) the amount it would have received for Energy Credits if the contract had reflected the newly determined Contract Energy level; and 2) the amount that the QF would have received under the applicable Variable Rate for energy provided during any period that exceeded the new Contract energy level. The charge, therefore, only captures whatever economic excess a QF that fails to provide the contracted-for energy obtains from operating under a levelized rate.

Q. WHAT IS THE PURPOSE OF THE REDUCTION-IN-CONTRACT-ENERGY-CHARGE?

A. The purpose of the Reduction-in-Contract-Energy-Charge is to ensure the economic balance of levelized QF contracts is maintained throughout the life of the contract. DEP includes the Reduction-in-Contract-Energy-Charge in levelized rate contracts because long-term levelized rates tend to overpay the QF in the early years and underpay QFs in later years.

Generally, energy costs, like other types of costs, increase over time and avoided energy costs are no exception. Consequently, when avoided energy rates are levelized over the life of a contract, the utility pays a QF more than the utility's avoided cost in the early years of the contract, which is offset by the fact that the levelized rate is expected to be less than the utility's avoided cost in the later years of the contract. Similarly, from a QF's perspective, the early years of a long-term levelized contract are more profitable than the later years. A QF's cost to operate (e.g., fuel and maintenance costs) will likely increase over time, but it receives the same payment for each kwh of energy it produces in the first year of a levelized rate contract as it does in the fifteenth year. The QF's profit margins, therefore, are greatest at the beginning of a levelized rate contract and are expected to decline throughout the term of the contract. As a result, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes, and could even disappear, over the life of a long-term levelized rate contract.

Given the economics of long-term QF contracts, it would be unfair to DEP and its customers for a QF to underperform during the latter part of its contract having already reaped the excess benefits provided by levelized rates in the earlier years of the agreement. The Reduction-in-Contract-Energy-Charge prevents that situation by providing a mechanism to adjust the contract to restore the expected balance of the economic benefits to both parties in the event the QF's performance falls materially short of its contractual obligation.

Q. HOW DO YOU RESPOND TO REG WITNESS MORRISON'S ASSERTION THAT THE REDUCTION-IN-CONTRACT-ENERGY-CHARGE IS PUNITIVE OR IS UNFAIR TO QFS?

A. The Reduction-in-Contract-Energy-Charge is neither punitive nor unfair. It merely restores the intended economic balance of the agreement in the event that a QF fails to deliver energy commensurate with the Contract Energy level. Moreover, DEP has never applied the Reduction-in-Contract-Energy-Charge in a punitive manner. The Reduction-in-Contract-Energy-Charge provision has been a part of DEP's Terms and Conditions since 1987 and this is the first time any party has objected to it. In fact, DEP has never had to resort to Reduction-in-Contract-Energy-Charge to resolve a performance issue with a QF. Thus, there is no basis for the assertion that the Reduction-in-Contract-Energy-Charge is in any way punitive to or an undue burden on QFs.

Q. **HOW DO YOU RESPOND TO REG WITNESS MORRISON'S ARGUMENTS THAT THE REDUCTION-IN-CONTRACT-ENERGY-CHARGE IS UNFAIR TO INTERMITTENT RESOURCES SUCH AS SOLAR AND WIND QFS THAT ARE NOT IN CONTROL OF WHEN THEY OPERATE?**

A. Such suggestions are unfounded. They greatly overstate the effect of the Reduction-in-Contract-Energy-Charge and ignore the responsibility of QFs to provide a reasonable, good faith estimate of their facilities generating capabilities.

The Reduction-in-Contract-Energy-Charge does not require QFs to predict their output perfectly. It is not triggered by a QF's failure to meet hourly, daily, monthly, or even seasonal production goals. The Reduction-in-Contract-Energy-Charge can only be invoked if the QF fails to meet its contracted-for energy targets over a 12-month period. Moreover, that calculation is based on a 12-month average of the QF's output, which gives the QF the benefit of any periods in which it produced energy in excess of the contracted-for amounts. Thus, a QF does not have to predict precisely its hourly or daily energy production to avoid the Reduction-in-Contract-Energy-Charge.

Moreover a QF's performance does not even need to perform up to its contractual representations. The Reduction-in-Contract-Energy-Charge only comes into play if the QF's output for a 12-month period falls below 80% of its contract energy level. This gives QFs a fairly wide margin of error before the application of the Reduction-in-Contract-Energy-Charge even becomes a possibility. It should also be noted that the Reduction-in-Contract-Energy-Charge only comes into play after the QF has operated for two years, which allows the QF time to work out any initial start-up issues. It also gives the QF two years to assess the actual operating capability of its facility and determine whether it can meet its contractual obligations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BY MS. FENTRESS:

Q Ms. Bowman, do you have a summary of your rebuttal testimony?

A (Ms. Bowman) I do.

Q Could you please give your summary?

A (Ms. Bowman) Sure. The purpose of my rebuttal testimony is to address issues raised by other parties pertaining to the avoided cost rates for solar and wind qualifying facilities and the utilities' standard QF contracts.

As to the various arguments presented to increase the path for solar and wind QFs, the utilities continue to believe that such an increase in the path violates the underlying principles of PURPA and would unfairly provide a windfall for solar and wind QFs at the expense of the utilities' customers. The PAF is simply a multiplier applied to the avoided cost capacity rates to increase the rates paid to QFs. Currently, the PAF is 2.0 for the avoided capacity rates paid small hydroelectric QFs and 1.2 for all others. The Commission should reject the proposed increase in the PAF for solar and wind QFs, which would effectively increase avoided capacity rates paid to such QFs by 67 percent and would impose an unnecessary and unjustified economic burden of millions of dollars on the utilities' customers.

The purpose of the present proceeding is to establish rates to be paid for power produced by QFs based on the individual utility's cost of alternative power. The goal is not to establish rates that ensure the profitability of QFs. Over time, a utility's avoided costs fluctuate based on a number of variables. Congress made it abundantly clear that under PURPA, no rate may be paid to a QF that exceeds the purchasing utility's avoided cost, even if the rate is not financially attractive to all types of QFs and QF developers.

Witness Morrison argues that DEP should be required to eliminate the provision of Section 6 of DEP's standard contract, referred to as the Reduction-in-Contract-Energy-Charge. This provision provides for a modification of the amounts paid to a QF in the event that the QF fails to provide the amount of energy called for in the contract. The purpose of the Reduction-in-Energy-Contract-Charge is to ensure the economic balance of levelized QF contracts is maintained throughout the life of the contract.

The Reduction-in-Energy-Contract-Charge is neither punitive nor unfair. It merely restores the intended economic balance of the agreement in the event that a QF fails to deliver energy commensurate with the contract energy level. Moreover, DEP has never applied the Reduction-in-Contract-Energy-Charge in a punitive manner. DEP has never had to resort to the Reduction-in-Contract-Energy-Charge to resolve a performance issue with a QF.

It should also be noted that the Reduction-in-Contract-Energy-Charge only comes into play after the QF has operated for two years, which allows the QF time to work out any initial startup issues. It also gives the QF two years to assess the actual operating capability of its facility and determine whether it can meet its contractual obligations.

This concludes my testimony.

Q Thank you. And now Mr. Snider, I will turn to you. You, too, have previously provided direct testimony in this proceeding; is that correct?

A (Mr. Snider) I have.

Q And did you cause to be prefiled in this docket, also, rebuttal testimony consisting of 40 pages and four exhibit?

A (Mr. Snider) I did.

Q And do you have any changes to make to that rebuttal testimony or to those exhibits at this time?

A (Mr. Snider) I do not.

Q And if you were asked the same questions today at this hearing, would your answers be the same?

A (Mr. Snider) Yes, they would.

MS. FENTRESS: I would request that the rebuttal testimony and exhibits of Mr. Snider be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: That motion will be allowed --

MS. FENTRESS: The exhibits premarked for identification.

COMMISSIONER BROWN-BLAND: -- and the exhibits will be premarked as they were when filed.

MS. FENTRESS: And I would like to note that for the court reporter's convenience, that Exhibit GAS 2 is confidential and Rebuttal Exhibit GAS-4 is confidential. And the pages of his testimony that are confidential are pages 4 through 5, 8 through 9, page 12, page 26, and pages 36 through 37.

(Whereupon, the public version of the prefiled rebuttal testimony of Glen A. Snider was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012	))))	REBUTTAL TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, INC., AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of DEC and Duke Energy Progress ("DEP"), also referred to as the Utilities in my testimony.

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

A. The purpose of my rebuttal testimony is to show that, despite the assertions made by other parties in this proceeding, the installed combustion turbine ("CT") costs used by DEC and DEP in calculating their proposed avoided capacity rates are reasonable and appropriate. Specifically, my rebuttal testimony addresses the following issues: 1) the reasonableness of the installed CT costs used by the Utilities in light of current CT cost data and the installed CT estimates used by the Utilities in previous filings; 2) using the average CT cost of a four-unit site is proper for calculating avoided costs; 3) the Utilities' use of contingency in their CT cost estimates is appropriate; 4) the Utilities' use of a 35-year useful life for in their CT cost estimates is appropriate; and 5) it was appropriate for the Utilities to exclude transmission system upgrade costs from their CT cost estimates. I will also address the specific CT cost estimate recommendations made by Renewable Energy Group ("REG") witness Reading and Public Staff witness Hinton and explain why their recommendations should not be accepted by the Commission

Q. PLEASE SUMMARIZE THE CONCLUSIONS THAT YOU MAKE IN YOUR TESTIMONY IN THIS PROCEEDING.

A. The CT cost estimates used by the Utilities in calculating their avoided capacity rates are reasonable and well-supported. They were based on cost studies by Burns & McDonnell ("B&M") and Sargent & Lundy ("S&L"), performed independently of each other. They are also supported by the testimony of the Utilities' outside expert witness Ted Pintcke of Black & Veatch ("B&V") and CT estimates developed by the Brattle Group, the United States Energy Information Administration ("EIA"), and the Electric Power Research Institute ("EPRI").

REG, the Public Staff, and North Carolina Sustainable Energy Association ("NCSEA") argue that the Utilities' CT costs should be higher. These parties make a number of arguments, including that the Utilities' cost estimates should be higher because CT costs are increasing, that the Utilities should use significantly higher contingency adders in their estimates, and that the Utilities should have ignored the economies of scale that naturally occur when multiple CTs are installed. I will address each of these arguments individually, but generally speaking, every piece of third party, independent cost data presented in this case fully supports the CT cost estimates used by the Utilities in their avoided capacity rates. Public Staff Witness Hinton notes correctly that cost estimates are affected by a large number of factors, which makes it difficult to develop single-point cost estimates. For this reason, the best cost estimates result from using several independently developed cost studies. That is what the Utilities did in this case and it confirms the reasonableness of the Utilities' CT cost estimates. The fundamental point is that the Utilities have presented CT cost estimates validated by overwhelming evidence and the other parties have presented no meaningful cost data to the contrary.

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

A. Yes. I am introducing Rebuttal Exhibits GAS-1 through 4 in support of my rebuttal testimony. Rebuttal Exhibit GAS-1 is the November 2012 Cost of New Entry ("CONE") Study Settlement filed with the Federal Energy Regulatory Commission on behalf of PJM and other PJM stakeholders.[1] Confidential Rebuttal Exhibit GAS-2 makes certain necessary adjustments to present the Brattle CONE Study estimate on a comparable basis to the DEC and DEP CT cost estimates. Rebuttal Exhibit GAS-3 presents a CT unit-cost comparison between the 2012 and 2013 *Gas Turbine World* publications to show that prices have, in fact, trended downward during this period. My Confidential Rebuttal Exhibit GAS-4 is DEP's response to Public Staff Data Request 3-4, which shows the actual CT costs used in the Reserve Margin Study.

I. <u>THE UTILITIES' CT COST ESTIMATES ARE REASONABLE AND APPROPRIATE</u>

Q. WHAT ARE THE CT COST ESTIMATES USED IN THE UTILITIES' AVOIDED CAPACITY COST CALCULATIONS?

A. DEP's proposed avoided capacity rates assume an installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and DEC's avoided capacity rates assume installed CT cost of **[BEGIN**

[1] *PJM Interconnection, L.L.C.*, Docket Nos. ER12-513-000, -003, Settlement Agreement and Offer of Settlement; (Nov. 21, 2012).

CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Q. **WHAT IS THE BASIS FOR YOUR POSITION THAT THE UTILITIES' CT COST ESTIMATES ARE REASONABLE AND APPROPRIATE?**

A. The installed CT costs used by the Utilities in developing their respective avoided cost rates were developed based on two independent and separately-commissioned cost studies (one by DEP and one by DEC) from two leading engineering firms –B&M and S&L. No party has identified or even suggested that there is any flaw or error in the B&M or S&L studies. In addition, Ted Pintcke of B&V has submitted testimony that further supports the CT costs used by the Utilities and suggests that those CT costs may actually be slightly higher than the current market indicates. Similarly, the PJM CONE Study prepared by the Brattle Group[2], and relied upon by Public Staff witness Hinton, further confirms that the Utilities' CT cost estimates are reasonable and appropriate.

Q. **HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS HINTON'S ASSERTION THAT THE CONE STUDY SUGGESTS A HIGHER CT COST THAN THE COST USED BY THE UTILITIES?**

A. For several reasons, the Brattle Group's CONE Study does not support witness Hinton's position.

First, witness Hinton does not actually rely on the CONE study. Rather, he purports to rely on the settlement agreement reached by certain parties in the FERC proceeding involving the CONE. In any negotiated settlement of a complex matter, the end result is a product of give-and-take on multiple issues and often involves trade-offs between issues. Using the CONE settlement is particularly troublesome because even the parties to that settlement described it as a "black box" settlement with "no agreement on any assumptions, estimates, or methodologies to calculate [the] specific values [agreed to]." (Rebuttal Exhibit GAS-1 at 11)

Second, witness Hinton asserts that the CONE settlement included a 3% increase in the installed CT cost used in the Brattle Group CONE study for the Dominion Zone of PJM. This is not the case. The values set forth in the black box settlement were annual costs on a \$/kw-yr basis and the settlement reflected a 3% increase from the annualized (\$/kw-yr) capacity cost the Brattle Group study calculated for the Dominion Zone. (*Id.* at 25, 51, 73) As witness Hinton acknowledges, annualized capacity costs involve more elements than the installed CT cost. (Hinton Direct at 9) It also includes carrying costs, O&M costs, line losses, etc. Thus, there is no way to determine from the "black box" CONE settlement how much of this 3% increase, if any, should be attributed to the installed CT cost.

Third, witness Hinton did not adjust the conservative summer-only rating of 196 MW per unit assumed by the Brattle Group. Even though the Utilities and Brattle Group all based their cost estimates on GE 7FA units, DEC and

DEP applied higher unit ratings in calculating their CT cost estimates. DEC used a summer rating of 201 MW and DEP used a winter/summer average rating of 213 MW. The difference between the ratings used by the Utilities and the Brattle Group may be due to the fact that the Brattle Group published its CONE study in mid-2011 and, therefore, may have used an older GE 7FA.03 CT model, as opposed to the GE 7FA.05 used by the Utilities for their CT cost estimates. In any case, witness Hinton's use of the lower unit rating assumed by the Brattle Group skews his \$/kw CT cost higher compared to the Utilities' cost estimates.

Finally, witness Hinton made no adjustment in his calculation for the fact that the Brattle Group's CONE cost estimate assumes the construction of a two CT site, as opposed to a four-unit CT site which serves as the basis for the Utilities' avoided cost rates. As a result, witness Hinton's analysis ignores the significant cost reductions that are achieved by adding additional units to a site and results in a CT cost estimate that is not equivalent to the Utilities' CT cost estimates.

As a result of the foregoing, the \$666/kw CT cost estimate that witness Hinton derives from the Brattle Group's CONE Study is overstated. In fact, when viewed on a truly comparable basis with the Utilities' CT cost estimates, it is clear that the Brattle Group's study supports the CT costs used in calculating the Utilities' avoided capacity rates.

Q. GIVEN THE FOREGOING, WHY DO YOU BELIEVE THAT THE BRATTLE GROUP'S CONE STUDY SUPPORTS THE CT COSTS USED BY THE UTILITIES IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. When the actual cost estimates set forth in the CONE Study are compared to the Utilities' cost estimates on an apples-to-apples basis, it is clear that the CONE Study is entirely consistent with the CT costs used by the Utilities.

The Brattle Group estimated that the installed CT cost (with AFUDC) for the Dominion Zone was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the CONE Study. This cost estimate was based on 2015/16 installation and assumed two GE 7 FA units at a single site and used a conservative summer-only unit rating of 196 MW. Conversely, the DEC and DEP CT cost estimates assumed 2012 installation, four GE 7 FA.05 units at a single site and the associated higher unit ratings. My Confidential Rebuttal Exhibit GAS-2 shows the adjustments to make the Brattle Group's CONE Study estimate comparable to the DEC and DEP estimates in terms of date of installation, unit ratings, and number of units per site.

Q. PLEASE EXPLAIN THE INFORMATION SHOWN ON YOUR CONFIDENTIAL REBUTTAL EXHIBIT GAS-2.

A. As Confidential Rebuttal Exhibit GAS-2 shows, when the straight-forward adjustments described above are made, the Brattle Group CT cost estimate is consistent with the Utilities' CT cost estimates. Rebuttal Exhibit GAS-2 compares the Brattle Group CT cost estimate to DEC's and DEP's estimates separately due to the difference in the unit rating assumptions used by DEC and DEP. These comparisons start with the actual installed cost estimate contained in the Brattle Group's CONE Study of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** which includes allowance for funds used during construction ("AFUDC"). The first adjustment takes that figure, which is presented in 2015 dollars, back to 2013 dollars. This produces a 2013 cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The next adjustment recognizes the difference between the Brattle Group's assumption of a rating of 196 MW per unit and the unit ratings used by DEC and DEP. This adjustment produces cost estimates of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** comparable to DEC's estimate and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** comparable to DEP's cost estimate.

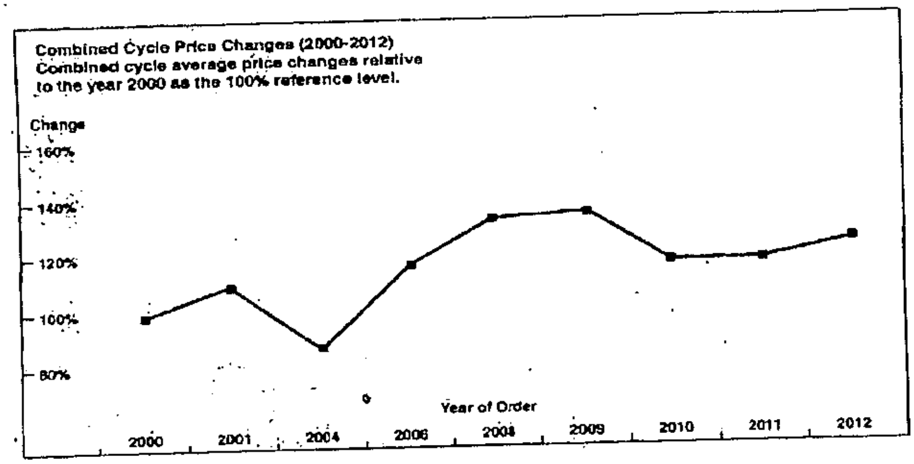
The final adjustment accounts for the difference in the economies of scale between the two unit site assumed by the Brattle Group and the four unit site assumed by the Utilities in calculating their avoided capacity costs. The B&M CT cost study shows that a cost reduction of approximately 10% can be realized between a two-unit site and a four-unit site. Confidential Rebuttal Exhibit GAS-2 shows that after making that adjustment, the results are almost identical to the Utilities' CT cost estimates.

Thus, like the B&M, S&L, and B&V analyses, the cost estimates contained in the CONE Study unequivocally demonstrate the reasonableness of the cost estimates used by the Utilities.

Q. **HOW DO YOU RESPOND TO THE ASSERTIONS OF WITNESSES READING AND HINTON THAT DEC AND DEP SHOULD HAVE USED CT COSTS THAT ARE HIGHER THAN THOSE USED IN THE UTILITIES' PREVIOUS FILINGS?**

A. REG witness Reading and Public Staff witness Hinton argue from a fundamentally incorrect premise that CT costs are rising. The truth is that CT costs have been gradually declining since they peaked in 2009.

Both witness Reading and witness Hinton rely upon information from the *2012 Gas Turbine World Handbook* ("*GTW 2012*") to support their assertion that CT costs are rising. Specifically, *GTW 2012* stated that an increase of 5-7% in CT equipment costs was expected in 2012. (Hinton Direct at 12; Reading Direct at 9) That assumption was reflected in the following chart showing the anticipated rebound in CT equipment costs in 2012.



Despite the prediction reflected in *GTW 2012*, the anticipated recovery in CT equipment costs has not occurred. This is demonstrated by comparing the CT prices listed in *GTW 2012* to the CT prices set forth in the *2013 Gas Turbine World Handbook* ("*GTW 2013*"), which are attached hereto as Rebuttal Exhibit GAS-3. As that information shows, CT equipment costs are declining. Compare, for example, the cost data for the GE 7FA Series 5 units that DEC and DEP assumed in calculating their avoided capacity rates. *GTW 2012* lists the cost for such equipment as $251/kw, whereas *GTW 2013* lists the cost for the same model CT equipment as $240/kw. Similar pricing declines can be seen for other GE turbines and other manufacturer's turbines. Clearly, the predicted rebound in CT equipment costs did not occur. If the actual declining cost trend had been plotted on the table above, it would show that after reaching their high water mark in 2009, CT equipment prices have gradually declined to a level that is below 2008 and 2010 levels. This is consistent with the observations of Utilities witness Pintcke that the current market for CTs is slow, which is depressing prices. (Pintcke Direct at 6)

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Significantly, the actual cost data in *GTW* supports the change in the CT costs from DEP's 2010 avoided cost rate filing and its current cost rate filing. As Public Staff witness Hinton notes, DEP used an installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for its 2010 avoided cost rates and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for its 2012 avoided cost rates. (Hinton Direct at 18) That is a decrease of approximately 15%. This is exactly the type of cost decrease that one would expect when the most recent cost data in *GTW* is considered in conjunction with the table above. To further put this in perspective, witness Hinton observes that from 1996 to 2010, the average change in installed CT costs used by DEP between avoided cost cases was 22.5%. During that same period, the average change in DEC's installed CT costs used in avoided cost rates was 19.5%. Thus, the 15% change in DEP's installed CT cost between its 2010 avoided cost filing and the present filing is consistent with the magnitude of changes in CT costs historically and in line with current cost data.

Q. HOW DO YOU RESPOND TO THE ASSERTIONS OF REG WITNESS READING AND PUBLIC STAFF WITNESS HINTON THAT THE CHANGE IN MARKET COSTS FOR CTS CANNOT EXPLAIN THE MAGNITUDE OF THE DECREASE IN THE CT COSTS USED BY DEC IN THIS PROCEEDING COMPARED TO PREVIOUS PROCEEDINGS?

A. The Utilities have never claimed, as Witnesses Reading and Hinton suggest, that the total change in DEC's CT cost estimates is due solely to decreasing CT costs. Rather, the Utilities have explained that much of the change in CT costs used by DEC is a result of DEC moving away from using a "worst case" scenario approach to estimating CT costs. As a result, DEC's current CT costs reflect a much smaller contingency adder. To put this in perspective, DEP's installed CT cost decreased 15% between its 2010 and 2012 avoided cost rate filings due largely to changes in the $/kw cost of CTs. The decrease in the installed CT cost used by DEC between its 2010 and 2012 avoided cost rate filings is 27%. The percentage decrease is larger for DEC because it reflects the effect of declining CT costs ***and*** DEC's use of an "expected case" contingency factor. Thus, while it is true that the decrease in DEC's CT costs from previous filings are not wholly explained by changes in the market cost for CTs, the Utilities have made clear that a significant portion of this change is due to DEC's use of lower contingency adders, not just changes in CT costs.

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS HINTON'S USE OF GENERAL INDUSTRY PRICE INDICES TO SUGGEST THAT CT COSTS ARE RISING?

A. Public Staff witness Hinton points to the Producer Price Index ("PPI") for Turbines and Turbine Generator Sets and CERA's Power Capital Cost Index ("PCCI") in arguing that the CT costs used in the Utilities' avoided cost rates should be increasing. (Hinton Direct at 12-14) However, these generalized, broad-based indices have limited probative value. The PPI is a compilation of data covering all kinds of turbines and related equipment. Consequently, one cannot draw any precise conclusions regarding cost trends regarding a specific type of turbine equipment. For example, a general cost index would not show the specific cost reductions for a particular type of turbine that is becoming larger and more efficient over time, which has been the case with F-frame CTs, such as the GE 7FA.

The PCCI has even less probative value than the PPI because it goes beyond multiple turbine types and includes costs for multiple generation types, including coal-fired, nuclear, wind, and solar generation. To illustrate, applying witness Hinton's interpretation of the PCCI, one would assume that the cost of installing solar and wind generation is increasing because the PCCI includes the cost of solar and wind facilities. Of course, as proponents of solar and wind power unfailingly argue, the capital costs for solar and wind generation has decreased over the last several years. Simply put, the PCCI reveals no more about the specific cost trends for conventional CTs than it does for solar and wind facilities.

Q. ARE THERE ANY OTHER ASPECTS OF THE COST DATA CONTAINED IN *GTW 2012* AND *GTW 2013* THAT SHOULD BE ADDRESSED?

A. Yes. Past CT costs should not be used as a means to measure the reasonableness of current CT cost estimates. Such an approach ignores technological innovations. Over time, CT manufacturers improve the output and efficiency of their turbines without an increase in price. The cost data in *GTW 2012* and *GTW 2013* is a prime example of such advances. In *GTW 2012,* the Siemens SGT6-5000F was listed with a unit rating of 208 MW and a price of $52 million. In the *GTW 2013,* however, the same unit was listed as having a unit rating of 232 MW and a price of $49 million. The net effect of those changes is that in one year the cost per kw of that unit dropped from $251/kw to $213/kw. This demonstrates the fallacy in the positions of REG, NCSEA, and Public Staff that past CT costs are an appropriate measure for current costs and that to the extent CT costs change they must increase.

II. THE CONTINGENCY ADDER USED BY THE UTILITIES' CT COST ESTIMATES IS REASONABLE AND APPROPRIATE

Q. WHAT CONTINGENCY ADDERS DID DEP USE IN ITS 2012 IRP AND ITS PROPOSED AVOIDED CAPACITY RATES?

A. For both its 2012 IRP and its proposed avoided cost rates, DEP applied a 5% contingency adder in calculating installed CT costs. A 5% contingency adder was also used for the CT cost estimates in the B&M study commissioned by DEP. S&L used a higher contingency adder (approximately 15%) in its study for DEC. The Utilities used the lower contingency adder reflected in the B&M study because it was consistent with their actual experience. As I explain in my direct testimony, since 2009, the Utilities have found that little or no contingency adder is necessary when constructing gas turbine generation. This includes combined cycle facilities, which are more complex than the simple cycle CTs that serve as the basis for the Utilities' avoided capacity rates.

Q. OTHER THAN THE UTILITIES' EXPERIENCE IN BUILDING COMBUSTION TURBINE GENERATION, DO THE UTILITIES HAVE ADDITIONAL SUPPORT FOR THEIR USE OF A 5% CONTINGENCY ADDER IN THEIR CT COST ESTIMATES?

A. Yes. As I mentioned previously, B&M, one of the leading engineering and construction firms in the utility sector, used a 5% contingency adder in their CT cost study. Also, as I noted in my direct testimony, EIA also uses a 5%

contingency in developing their estimates of current CT costs. Similarly, the Brattle Group used a 5% contingency in developing its CT cost estimates in the CONE study. (Rebuttal Exhibit GAS-1 at 15)

Q. HOW DO YOU RESPOND TO THE SUGGESTIONS OF WITNESSES READING AND HINTON THAT THE UTILITIES SHOULD HAVE USED A HIGHER CONTINGENCY ADDER IN THEIR CT COST ESTIMATES?

A. The positions taken by REG witness Reading and Public Staff witness Hinton are incorrect for two reasons: 1) the sources they cite do not actually support their position; and 2) their positions are inconsistent with the purpose of the avoided cost rate process.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT THE SOURCES CITED BY WITNESSES READING AND HINTON DO NOT SUPPORT THEIR POSITION?

A. Both witness Reading at page 17 of his direct testimony and witness Hinton at page 26 of his direct testimony cite a B&V report entitled *Cost and Performance Data for Power Generation Technologies (2011)* ("*B&V Cost Report*") for the proposition that non-site specific cost estimates might include contingencies of 20-30%. However, this statement is taken out of context and is inapplicable to the Utilities' use of contingency adders in this proceeding.

The portion of the *B&V Cost Report* cited by witnesses Reading and Hinton is contained in an introductory portion of the report, which explains why the cost projections in the report should not be taken as single point estimates. (B&V Cost Report at 7-8) It is important to note that the *B&V Cost Report* is a compilation of general industry data used to produce generic cost projections for building multiple types of generation (including new and emerging technologies) in the United States through 2050. Given the nature of such projections, it is understandable why B&V would be careful to hedge its projections. Moreover, witnesses Reading and Hinton ignore that B&V observed that "[m]ature technologies have a smaller band of uncertainty around their costs...." (*Id.* at 3) Even more telling, with regard to conventional CTs specifically, the *B&V Cost Report* states that the "[c]ost uncertainty for this technology is low." (*Id.* at 11)

The statements in the *B&V Cost Report* must be considered in light of their specific intent. B&V was discussing how project estimates might be done in the absence of detailed information. In such a situation, uncertainties may exist in a number of areas, including: 1) site availability and suitability; 2) generation type and configuration; 3) timing of the project; and 4) the amount of detail that is put into the cost estimate. None of those uncertainties are significant issues for the CT cost estimates relied upon by the Utilities.

Even though the Utilities' estimates in this case are not based on a specific site, issues associated with the suitability and availability of a site are mitigated by the fact that the owners of the projected CTs are public utilities with the power of eminent domain. As to generation type, the estimates are not just based on generic assumptions regarding CTs, but rather are based on specific CT models (i.e., GE 7FA.05) and a specific four-unit configuration. Both the CT type and the four-unit configuration are common and well-understood. Moreover, the cost estimates in question are not based on an uncertain project date or a hypothetical date in the distant future. They are based on an assumption of immediate construction, which eliminates the uncertainties associated with the timing of the project. Additionally, the Utilities based their CT costs on cost studies performed by B&M and S&L. These were not generic cost estimates based on broad industry data.

Thus, the nature of the cost studies used by the Utilities simply do not justify the large contingency adders suggested by REG witness Reading or Public Staff witness Hinton. Tellingly, neither witness Reading nor witness Hinton provide a single concrete example of the use of a contingency adder of that magnitude in cost estimates of this type.

Q. DO THE OTHER PARTIES PROVIDE ANY OTHER SUPPORT FOR THEIR POSITION THAT THE UTILITIES SHOULD HAVE USED LARGER CONTINGENCY ADDERS IN THEIR CT COST ESTIMATES?

A. On page 14 of his direct testimony, REG witness Reading suggests that a larger contingency adder is warranted to account for uncertainties in macro-economic conditions, such as the domestic fiscal conditions and economic conditions in Europe and China. This argument ignores the fact that these conditions can just as easily lead to cost decreases. Further, any potential impact from global economic factors is mitigated in the context of avoided costs by the fact that avoided cost rates are reset every two years. Concerns pertaining to macro-economic volatility may have some relevance to cost estimates for projects that take years to complete (e.g., nuclear plant construction) or to projects that are decades in the future. However, such concerns simply have no bearing on current cost estimates for CTs that are updated biennially.

Q. **PREVIOUSLY YOU STATED THAT THE POSITIONS OF WITNESSES READING AND HINTON ARE INCONSISTENT WITH THE PURPOSE OF AVOIDED COST RATE PROCEEDINGS. WHAT DO YOU MEAN?**

A. Avoided capacity rates must be based on the costs that the utility actually expects to incur if it has to build capacity rather than purchasing power from a QF. Thus, in this case, the Utilities' avoided capacity costs must be based on the cost one would reasonably expect them to incur to build CT capacity. The positions taken by witnesses Reading and Hinton are not consistent with that principle.

REG witness Reading and Public Staff witness Hinton suggest that the Utilities should have adopted the approach used by bidders and project managers for the most preliminary of project estimates. This approach would require a contingency large enough to account for every possible risk, including risks that have not yet been identified. Such a "worst case scenario" method of determining contingency may be acceptable in developing a "not to exceed" preliminary project estimate, but not in the development of avoided cost rates.

III. THE UTILITIES PROPERLY BASED THEIR CT COST ESTIMATES ON THE AVERAGE COST OF A FOUR-UNIT SITE AND THE RESULTING ECONOMIES OF SCALE

Q. PLEASE EXPLAIN WHY THE UTILITIES BASED THEIR CT COST ESTIMATES ON THE AVERAGE COST OF A FOUR-UNIT SITE?

A. Historically, DEC and DEP have constructed their CTs on multiple unit sites. Of the ten sites on which DEP has built CTs, six have four or more units and one has three units and a large combined cycle combustion turbine plant. The other three sites consist of two sites with small (15 MW) oil-fired units that are not comparable to the type of CT used to calculate DEP's avoided capacity rates and a remote site in Asheville that has two CTs. Similarly, three of DEC's four CT sites have four or more units. The fourth is a two-unit site that is utilized as a back-up source of generation to a nuclear site. Because the Utilities typically construct CTs with at least four units at a site, it is reasonable to use the four-unit configuration as the basis for their avoided capacity rates. Furthermore, in using the average cost of a four-unit site, the Utilities are following the guidance recently provided by the Commission in the EPCOR arbitration *See Order on Arbitration* Docket No. E-2, Sub 966, (January 26, 2011) *("EPCOR")*. My understanding is that the Commission, in its EPCOR order, specifically rejected the same argument being made here by the intervenors and ruled that the proper way to calculate DEP's avoided capacity cost is to use the average unit cost to construct four CTs at a plant site.

In my opinion, nothing has changed in the 20 months since the *EPCOR* order was issued to warrant a change in the Commission's analysis for either DEP or DEC.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF WITNESS READING THAT THE UTILITIES' AVOIDED CAPACITY RATES SHOULD BE BASED ON THE COST OF A ONE-UNIT SITE?

A. In general, the arguments raised by REG witness Reading are the same arguments that the Commission considered and rejected in *EPCOR*. More specifically, the arguments of witness Reading are inconsistent with the Peaker Methodology upon which the Utilities' avoided cost rates are based.

The Peaker Methodology combines a utility's cost of building CT capacity with the utility's incremental cost of energy (i.e., its highest energy cost for each hour) to produce avoided cost rates. Consequently, under this methodology, the avoided capacity rates are based on CT costs regardless of the type and amount of generation that the utility plans to build. Nevertheless, witness Reading suggests that the Utilities should ignore the fact that their practice is to build four or more CTs at a single site because the Utilities may not have immediate plans to develop a four-unit CT site. (Reading Direct at 22 and 27-28)

The specific generation additions reflected in the Utilities' resource plans are not relevant to the calculation of avoided capacity rates under the Peaker Methodology. If that were the case, the calculations would work both ways and Utilities would be paying avoided capacity rates of zero during years in which they are not adding new capacity. It is doubtful witness Reading would support this model in that instance. In any event, the implication of witness Reading's position that a prudent utility would adopt a policy of only developing single-unit CT sites is implausible.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF WITNESS HINTON THAT THE UTILITIES' AVOIDED CAPACITY RATES SHOULD BE BASED ON THE COST OF A TWO-UNIT SITE?

A. Public Staff witness Hinton takes a slightly different approach than witness Reading. Witness Hinton argues that the current value of combined cycle generation suggests that the Utilities are less likely to build CTs and, therefore, may depart from their practice of building four or more units at a single site. (Hinton Direct at 23-24) The implication of this argument is that a change in DEC's and DEP's approach to developing multi-unit CT sites would also warrant a change in the siting assumption used in developing their avoided capacity rates.

First, as the individual responsible for resource planning for both DEC and DEP, I can state unequivocally that both of the Utilities will continue to pursue CT development as an option to meet their obligation to provide least cost power to their customers. That means that siting four or more CTs at a single site will continue to be the rule for DEC and DEP, not the exception. This is the most cost-effective approach to developing CTs because it optimizes the economies of scale associated with multi-unit sites. Spreading the cost of land, site preparation, roadways, gas infrastructure, electric transmission infrastructure, water infrastructure, and administrative and auxiliary buildings among several units (instead of just one or two) significantly lowers the average capital cost of the CTs. That is why the Utilities have historically sited CTs at sites with four or more units and why they will continue to do so.

Second, witness Hinton's argument is based on an apparent misunderstanding of the nature of economies of scale gained by multi-unit siting of CTs. Witness Hinton appears to assume that, if current market conditions cause the Utilities to favor combined cycle units over CTs, the resulting delay in the construction of CTs will result in more two-unit sites. This assumption ignores the fact that the economies of scale achievable by siting several CTs at a single site are not dependent on building all of the CTs at the same time. Thus, while it is conceivable that current circumstances could cause the Utilities to initially build a two-unit CT site, nothing would prevent them from subsequently adding more CTs to that site. Alternatively, the Utilities might build two CTs, but co-locate them with combined-cycle units, thereby achieving the same type of economies of scale as are achieved with a four-unit site. In any event, I expect the Utilities to continue to pursue the development of CTs in a manner that achieves economies of scale comparable to those reflected in their avoided capacity rates.

Q. HOW DO YOU RESPOND TO THE ASSERTION OF PUBLIC STAFF WITNESS HINTON THAT THE UTILITIES' CT COST ESTIMATES OVERSTATE THE EFFECT OF ECONOMIES OF SCALE ASSOCIATED WITH BUILDING FOUR UNITS AT A SINGLE SITE?

A. Importantly, DEC and DEP did not calculate a specific measure of economies of scale for their CT cost estimates. They based their CT cost estimates on the cost studies performed by B&M and S&L for the average CT cost based on a four-unit configuration. The Utilities did not direct B&M or S&L to assume a particular amount of savings due to economies of scale. B&M and S&L independently developed their cost estimates and any economies of scale assumed in their cost studies are a product of their own experience and judgment.

The effect of the economies of scale is more evident in the B&M study because B&M broke down its four-unit cost estimate between the cost of the first unit and subsequent units. B&M's first-unit cost estimate includes the full cost of elements such as land, site development, shared infrastructure and facilities. The costs for subsequent units do not include these initial costs and, therefore, are lower. S&L did not provide a breakdown of estimated CT costs by first and subsequent units. It simply provided a cost of the entire four-unit CT site. As a result, S&L's consideration of economies of scale is not as apparent. Nonetheless, S&L and B&M ultimately arrived at very similar cost estimates for the cost of a single site with four GE 7FA.05 units. It is, therefore, reasonable to conclude that their assumptions as to the effect of economies of scale on such a project were comparable.

The Utilities' actual experience also confirms that co-locating CTs at a single site can produce significant cost savings. For example, DEP completed the last of five CTs located at its Wayne County site in May 2009. As the data in *2012 GTW* shows, 2009 was the period when CT costs peaked. DEP's avoided cost rate filings confirm this fact because DEP used a CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in its 2008 avoided capacity rates, which represented a 64% increase from the CT costs used by DEP in its 2006 avoided capacity rates. Despite being built at the height of the CT market, the last Wayne County CT was built for only **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

A comparison of the CT cost estimates produced by EPRI further illustrates the significance of the cost savings associated with constructing multiple CTs at a single site. EPRI has estimated that the cost of building a single GE 7FA unit to be $637/kw (in 2011 dollars). On the other hand, EPRI has estimated the cost of building three such CTs on a single site to be only $558/kw (in 2010 dollars). While a small portion of the difference in these cost estimates may be due to the difference between 2011 and 2010 costs, the vast majority of these savings must be attributed to the economies of scale associated with building two additional units at the same site. Such cost reductions would be even greater if, as the Utilities have for purposes of their avoided capacity calculations, EPRI has assumed a four-unit site as opposed to a three-unit site. Thus, whatever doubts witness Hinton may have regarding the magnitude of savings to be derived by building four or more CTs at a single site, the Utilities' experience and the cost studies conducted by B&M, S&L, and EPRI confirm that those savings are real and they are significant.

Witness Hinton does not cite any studies, reports, or data to support his position that the economies of scale reflected in the B&M and S&L studies are over-stated. He does refer to the testimony of Utilities' witness Pintcke, who stated that such economies of scale could be "25% or more" on the balance of plant costs. (Hinton Direct at 22) Witness Pintcke further noted that balance of plant costs are only approximately 40% of the total cost of a CT. (Pintcke Direct at 4) However, witness Hinton seems to ignore that witness Pintcke stated that the economies of scale saving on balance of plant costs could be "25% ***or more.***" (Pintcke Direct at 8) Clearly, witness Pintcke was describing the minimum savings that one would expect by siting four CTs at a single site. More importantly, Public Staff witness Hinton disregards witness Pintcke's ultimate conclusion that his "experience leads me to expect that the $/kw cost of a four CT site would be in the range of 15% to 25% less than the $/kw cost of a single CT greenfield." (Pintcke Direct at 8) That range of savings from economies of scale is consistent with the savings reflected in the B&M study, the EPRI cost estimates, and the Utilities' experience.

IV. THE UTILITIES' USE OF A 35-YEAR USEFUL LIFE FOR CTS IN CALCULATING THEIR AVOIDED CAPACITY RATES IS REAONABLE AND APPROPRIATE

Q. HOW DO YOU RESPOND TO REG WITNESS READING'S ARGUMENT THAT THE UTILITIES SHOULD NOT HAVE USED A 35-YEAR USEFUL CT LIFE IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. Witness Reading's arguments regarding the Utilities' use of a 35-year useful CT life are completely unsupported and without merit. In the Utilities' Reply Comments and my direct testimony, the Utilities have shown that: 1) the actual operating lives of the Utilities' CTs are 35 years or more; and 2) the 35-year CT useful life assumption is consistent with the useful life assumption used in setting the Utilities' current retail rates. Given those facts, it is clear that 35 years is an appropriate useful life for the Utilities to use in calculating their avoided capacity rates. REG witness Reading presents no evidence to contradict those facts.

Rather than providing specific evidence regarding the useful life of the Utilities' CTs, witness Reading points to e-mail exchanges among the DEC and DEP employees to support his position. (Reading Direct at 19) These e-mails, however, do nothing to further witness Reading's arguments. As noted in my direct testimony, the Utilities engaged in collaborative process after the Duke-Progress Merger to begin developing best practices. This process included review and discussion of the Utilities' respective approaches to

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calculating their avoided cost rates. One of the issues that was discussed at length was the useful CT life estimate to be used in setting avoided capacity rates. Ultimately, it was determined that a 35-year useful life was appropriate given the actual operational lives of the CTs and the assumptions underlying the Utilities' retail rates. Because this assumption constituted a change for both DEC (which previously used a 30-year life) and DEP (which previously used a 25-year life), it is understandable that there was considerable discussion of it. The e-mails quoted by witness Reading merely reflect the kind of robust and open debate around this issue that is to be expected and that the Utilities in fact encourage. These exchanges in no way diminish the fact that the 35-year useful life is fully supported by and consistent with the actual operating lives of the Utilities' CT fleet and the manner in which the Utilities' retail rates are set.

Witness Reading also suggests that if the Utilities adopt a longer useful life for their CTs then they should have increased the variable O&M expense rate associated with their CTs. (Reading Direct at 26) His assumption is that a longer useful life would equate to a higher cost to operate and maintain the unit. (Reading Direct at 19-20) Witness Reading's argument, however, proceeds from a false premise. The variable O&M included in the Utilities' avoided cost rates are based on their actual variable O&M expense from a mix of CT and non-CT generation. This includes cost data from the Utilities' CTs, including those that have been in operation for 35 years or more. Thus, the variable O&M expense reflected in the Utilities already account for effects of a 35-year useful CT life.

V. IN CALCULATING THEIR AVOIDED CAPACITY COSTS, THE UTILITIES PROPERLY EXCLUDED THE COST OF TRANSMISSION NETWORK SYSTEM UPGRADES

Q. WHAT IS YOUR UNDERSTANDING OF THE ISSUES RAISED IN THIS PROCEEDING REGARDING THE UTILITIES' APPROACH TO EXCLUDING TRANSMISSION NETWORK SYSTEM UPGRADE COSTS IN THIER AVOIDED CAPACITY RATES?

A. Public Staff witness Hinton and REG witness Reading suggest that Network System Upgrade costs associated with installing a hypothetical CT should have been included in developing the Utilities' avoided capacity costs. Traditionally, DEC has included such upgrade costs in its avoided capacity rates and DEP has not. For purposes of the present case, it was determined that neither DEC nor DEP would include such costs in their avoided capacity rates. However, the Utilities have included the cost of transmission interconnection in their avoided capacity cost calculations.

Q. WHAT IS THE DIFFERENCE BETWEEN INTERCONNECTION COSTS AND NETWORK SYSTEM UPGRADES COSTS?

A. Network upgrades, unlike interconnection costs, involve improvements to the transmission system beyond merely connecting a generation resource to the transmission system. Such upgrades are needed to accommodate the anticipated increases in power flows as growing load is met from sources such as new generating facilities or new power purchases.

Sometimes a utility's construction of new generation facilities will require transmission upgrades, but not all new generation additions require such upgrades. A number of factors, including the current state of the transmission system, the amount and type of generation being added to the system, and the location of the new generation can influence whether network upgrades are required by the addition of new generation. Moreover, network upgrades can range from minor additions such as a bank of capacitors to the enormously expensive undertakings such as the construction of a new transmission line. All other things being equal, utilities will try to plan their generation additions to avoid or minimize the need for network upgrades. As the foregoing makes clear, although all generation requires interconnection, not all generation necessitates network upgrades.

Buying power from a QF allows a utility to avoid interconnection costs because: 1) the utility "avoids" the interconnection costs associated with the CT capacity that it is avoiding; and 2) the QF is fully responsible for the interconnection costs associated with its own facility. This is not the case for network system upgrades, however, and, therefore, the cost for such upgrades has not been included in the Utilities' avoided capacity rates.

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Q. WHY HAVE THE UTILITIES' EXCLUDED NETWORK SYSTEM UPGRADE COSTS FROM THEIR AVOIDED CAPACITY RATES?

A. The Utilities' did not include network system upgrade costs in their avoided capacity rates because those types of costs are not "avoided" in the sense required by PURPA. As noted above, interconnection costs for a CT are considered avoided because if a utility buys power from a QF, rather than building a CT, the utility avoids the interconnection cost ***and*** the QF, not the utility, is responsible for the interconnection costs associated with the QF. However, unlike the situation with interconnection costs, small QFs are not responsible for any network system upgrade costs associated with the addition of its facility. DEC and DEP do not require comprehensive system impact and facilities studies for small QFs to interconnect. Without such studies, any network transmission upgrades required to accommodate incremental additions of small QF generation (individually or in aggregate) are borne by the Utilities and their customers.

Q. HOW DO YOU RESPOND TO THE ASSERTIONS OF REG WITNESS READING AND PUBLIC STAFF WITNESS HINTON THAT SMALL QFS ARE UNLIKELY TO CAUSE OR CONTRIBUTE TO THE NEED FOR NETWORK SYSTEM TRANSMISSION UPGRADES?

A. Neither witness Reading nor witness Hinton provide any specific support for their supposition that the addition of numerous small QFs to the Utilities' system would impose little or no costs or impacts on the Utilities' transmission system. For example, witness Hinton merely opines that it is "unlikely" that an aggregation of 5 MW QFs distributed throughout a utility's system would have the same network system impact as a single 200 MW CT at a single location.

The implication of witness Hinton's statements is that installing QFs are "unlikely" to contribute to the need for network system upgrades and therefore the fact that the Utilities and their customers are responsible for any such upgrades is moot. This argument, however, misses the point. Regardless of how likely it is that the installation of numerous QFs will contribute to the need for network system upgrades, the fact remains that the Utilities and their customers, not the QFs, bear the full cost responsibility for them. It would be unfair and inconsistent with PURPA for the Utilities' customers to pay for "avoided" network system upgrade costs through rates paid to QFs ***and*** to pay for the cost of network system upgrades necessitated by the QFs.

Finally, it is not certain that distributed QFs will not cause or contribute to the need for network system upgrades. Unlike the Utilities, QFs are not required or incented to site their facilities in the most efficient location possible. Accordingly, QFs seek to interconnect to the Utilities' systems where it is most financially advantageous for them and issues associated with transmission impacts are not relevant to QFs when they select a site for their facilities. In fact, the predominant factors affecting QF siting decisions, such as, land costs, suitability of topography, atmospheric conditions, proximity to fuel sources, and tax credit advantages, have nothing to do with transmission issues. As a result, multiple new QFs may be located in clusters or be located at particularly disadvantageous locations from a transmission perspective. Consequently, one cannot simply assume that it is "unlikely" that no network transmission upgrades will be necessitated by adding hundreds of MWs of new QF capacity to the Utilities' system. It follows that it would be inappropriate to require the Utilities and their customers to bear the risk of paying twice for network system upgrades – once through the avoided cost rates paid to QFs and once if the QFs contribute to the need for network system upgrades.

VI. RESPONSE TO THE SPECFIC RECOMMENDATIONS OF WITNESS READING

Q. WHAT ARE THE CT COSTS THAT WITNESS READING RECOMMENDS THAT DEC AND DEP SHOULD BE REQUIRED TO USE IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. REG witness Reading recommends that DEC be required to use CT cost of $742/kw and that DEP be required to use CT cost of $725/kw.

Q. TURNING FIRST TO DEC, HOW DO YOU RESPOND TO REG WITNESS READING'S RECOMMENDATION THAT DEC BE REQUIRED TO USE A CT COST $742/KW FOR ITS AVOIDED CAPACITY RATES?

A. I am not aware of any cost data that would support $742/kw as a cost that DEC would reasonably be expected to incur for new CT capacity. Even the study that witness Reading cites, *The B&V Cost Study*, only quotes an installed CT cost of $651/kw and that is for a single-unit site.

Q. DOES REG WITNESS READING PROVIDE ANY SUPPORT FOR HIS RECOMMENDATION?

A. He does not provide any meaningful support for his recommendation. He relies on the CT cost estimates filed by DEC in previous proceedings. (Reading Direct at 12-14) As I noted above, past CT cost estimates are a poor indicator of current CT costs. Moreover, DEC's previous filings were based on the conservative approach of using high contingency adders (i.e., worst case scenario cost estimates). Consequently, DEC's previous filings do not provide meaningful evidence of actually anticipated, current costs to construct a CT.

Q. HOW DO YOU RESPOND TO REG WITNESS READING'S RECOMMENDATION THAT DEP BE REQUIRED TO USE A CT COST OF $725/KW FOR ITS AVOIDED CAPACITY RATES?

A. REG witness Reading's recommendation as to DEP has even less validity than his DEC recommendation. In the case of DEP he cannot even rely on specious comparisons to DEP's previous filings because his recommendation is significantly higher than any CT cost estimate used by DEP in any regulatory proceeding. Moreover, in an effort to gloss over the lack of support for his recommendation, he mischaracterizes cost data contained in DEP's previous filings.

First, he cites the $1,784/kw cost of 42 MW fast-start turbines from DEP's resource plan to show the "CT cost that DEP actually will incur…." (Reading Direct at 25) Of course, the fast-start CT bears no relationship to avoided cost calculations. It is an entirely different type of generation from the conventional CTs used to determine avoided costs under the Peaker Methodology. Fast-start units are installed for their ability to respond quickly to system conditions and emergencies, but that capability causes these units to have very high capital costs relative to other types of generation. Thus, the cost of a fast-start unit is as irrelevant to the calculation of avoided capacity rates using the Peaker Methodology as the cost of a nuclear plant. Moreover, witness Reading is well-aware of that fact because it was explained in response to a REG data request. (*Id.* at 24-25)

Second, witness Reading alleges that DEP used a CT cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in its 2012 IRP. Clearly, witness Reading is relying on the estimated cost of a single CT from DEP's 2012 IRP, which is not appropriate for the calculation of avoided capacity costs. Moreover, witness Reading has ignored the fact that the CT cost estimate used in DEP's 2012 IRP is actually ***lower*** than the CT cost estimates used to calculate DEP's avoided capacity rates. (*See, e.g.*, Utilities Reply Comments at 12-14) Further, witness Reading provides no explanation how a cost estimate for a ***single*** CT of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** provides any support for his recommendation that a CT cost of $725/kw be used for DEP's avoided cost capacity rates.

Third, witness Reading erroneously alleges that DEP used a CT cost estimate of $818.50/kw in its 2012 Generation Reserve Margin Study. (Reading Direct at 24) This figure is simply wrong. In fact, the overnight CT cost estimate reflected in that study was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the average cost of a four-unit site. While that cost estimate is higher than the CT cost estimate used by DEP in its current avoided capacity rates, the difference is due to the fact that DEP's Reserve Margin Study was based on 2011 generic unit cost estimates, which were produced when CT costs were higher than they are currently.

In any event, nothing in DEP's 2012 Generation Reserve Margin Study provides any support for the inflated CT cost quoted by witness Reading. His error is particularly confusing given that DEP made the actual CT cost estimates used in its Reserve Margin Study available to the other parties in this case, including REG. Attached to my testimony as Confidential Rebuttal Exhibit GAS-4 is DEP's response to Public Staff Data Request 3-4, which shows the actual CT costs used in the Reserve Margin Study. This data request response was served on REG as well as the Public Staff.

In sum, nothing in witness Reading's testimony provides any legitimate credence to his recommendations and they should be given no weight by the Commission.

VII. RESPONSE TO THE SPECFIC RECOMMENDATIONS OF PUBLIC STAFF WITNESS HINTON

Q. WHAT IS THE CT COST THAT PUBLIC STAFF WITNESS HINTON RECOMMENDS THAT DEC AND DEP SHOULD BE REQUIRED TO USE IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. Public Staff witness Hinton recommends that both DEC and DEP should be required to use a CT cost of $650/kw for their avoided cost rates. He states that this recommendation is based on his opinion that $625/kw to $675/kw is a reasonable range for cost building new CT capacity. Although his recommendation is not as excessive as witness Reading's recommendations, Public Staff witness Hinton's proposed CT cost is still unreasonably high.

Q. WHY DO YOU BELIEVE THAT PUBLIC STAFF WITNESS HINTON'S RECOMMENDATION OF A $650/KW CT COST IS TOO HIGH TO BE USED FOR CALCULATING THE UTILITIES' AVOIDED CPACITY RATES?

A. His recommendation is out of line with all of the independent CT cost studies presented in this case. B&M, S&L, B&V, and the Brattle Group have all produced CT cost studies that result in CT costs that are significantly lower than witness Hinton's recommendation. Similarly, the overnight cost estimates for a single CT produced by EIA ($664/kw) and EPRI ($637/kw) suggest that witness Hinton's recommended CT cost is too high.

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While witness Hinton's recommendation of $650/kw is out of line with the other cost data presented in this proceeding, the cause of this discrepancy is unclear because his recommendation is unaccompanied by any back-up or explanation. Without such information, there is no way to discern what estimates and assumptions form the basis of his recommended CT cost. For example, witness Hinton provides no indication of: 1) whether he is estimating the cost of a one, two, three or four unit site; 2) the model of CT he assumes; 3) the assumed rating of the CT(s); 4) whether transmission costs are included in his cost estimate (and if so how much transmission cost is included); and 5) how much contingency is included in the CT cost estimate.

While the bases for witness Hinton's recommendation are not evident from his testimony, it is clear he could only have arrived at his recommended CT cost by assuming some combination of factors that are not appropriate for the calculation of the Utilities' avoided capacity costs. For instance, witness Hinton's recommendation may be inflated by assuming a single-unit or two-unit site as the basis of his cost estimate. Such an assumption, however, would not be an appropriate basis for calculating the Utilities' avoided capacity rates given their actual pattern of siting four or more CTs at a single site and the Commission's ruling in *EPCOR*. Similarly, witness Hinton's recommended CT cost may have been increased by the inclusion of a substantial amount of transmission system upgrade costs, which would be inconsistent with the Utilities' practice of not charging small QFs for network system upgrades. Regardless of the cause, witness Hinton's recommended CT

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cost is significantly higher than the Utilities' anticipated cost of CT capacity and, therefore, is too high to be used as the basis for the Utilities' avoided capacity rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

(Whereupon, Rebuttal Exhibits GAS-1 through GAS-4 were identified as premarked.)

BY MS. FENTRESS:

Q Mr. Snider, do you have a summary of your testimony?

A (Mr. Snider) Yes, I do.

Q Would you please give your summary?

A (Mr. Snider) Yes. The purpose of my rebuttal testimony is to address the issues raised by the Renewable Energy Group, North Carolina Sustainable Energy Association, and the North Carolina Public Staff. I first address the issue of the CT cost estimates, demonstrating that the intervenors either inappropriately applied or misread studies they relied upon for opposing the CT cost used by the utilities. I demonstrate that the 5 percent contingency figure used by utilities is consistent with the utilities' actual experience, as well as external studies. I detail how the CT cost estimate used by the utilities in calculating their avoided capacity rates are reasonable and well supported.

I also demonstrate that the utilities appropriately relied upon an average CT cost of a four-unit site for calculating avoided costs, given the utilities typically construct CTs with at least four units at a site. Furthermore, in using the average cost of a four-unit site, the utilities are following the guidance provided by the Commission in the EPCOR arbitration.

With regard to the intervenor's challenge of the use of the utilities 30 -- or use of a 35-year useful life in their CT cost estimates, I demonstrate the appropriateness of this value based on the fact that the utilities' CTs have experienced useful lives of 35 years or more and that this assumption is consistent with what was used by the utilities in setting their current rates.

Finally, I demonstrate in my rebuttal testimony that it was appropriate for the utilities to exclude transmission system upgrade costs from their CT cost estimates. While the utilities have included the cost of direct interconnection in the development of their avoided cost rates, the cost of network upgrades for small QFs are not truly avoidable. This is because both QF and traditional generation require a reliable transmission infrastructure to deliver their respective energy and capacity.

This concludes the summary of my rebuttal testimony.

MS. FENTRESS: The panel is available for cross examination.

COMMISSIONER BROWN-BLAND: Mr. Youth?

CROSS EXAMINATION BY MR. YOUTH:

Q Mr. Snider, are you familiar with Duke's 2013 IRP?

A (Mr. Snider) I am.

Q I apologize. I do not have an exhibit to hand out to you, but do you recall page 22 of NCSEA Bowman Exhibit 1 that was handed out yesterday? There's a page in Duke's 2013 IRP that says, "By the end of the planning horizon, the Company will have met over 700 MW of peak demand through solar resources, the equivalent of one large natural gas facility." I think yesterday when I asked so solar will help to avoid a large Duke gas facility, the question was referred to you. Is that accurate, my understanding that in the IRP, Duke is projecting that increased incorporation, integration of solar resources will help defer or avoid the need for one large natural gas facility?

A (Mr. Snider) Yes. To be clear, in the IRP, we calculate and project by 2028, at the end of the planning horizon we'll have 1,700 or approximately 1,689 MW of installed solar, which we will then, because about 40 percent of that is available to defer peak need, when you apply that 40 percent to that 1,700 of installed, it will allow us to avoid one 700 MW plant commensurate with the 1,700 MWs of installed. So, yes, that is correct.

Q And so I think there's been some talk about the interconnection queue and two GW, three GW being in that interconnection queue. In the IRP, Duke is planning for 1,689 MWs by 2028; is that correct?

A (Mr. Snider) Yes. That's Duke Energy Carolinas only.

Q And I would also ask if you're familiar with Duke's 2012 Commission approved IRP. Is it accurate to say that QF solar helped defer Duke's next capacity need, as represented in that 2012 IRP?

A (Mr. Snider) I don't have the 2012 IRP in front of me. If you could, please, provide it. Sorry.

Q Could you tell me what page number you're looking at, Mr. Snider, on that cross exhibit?

A (Mr. Snider) It's cross exhibit page 30.

Q And if you look at the arrow, after you've had an opportunity to read that, I'll ask again, based on that 2012 IRP, did QF solar help defer Duke's next capacity need?

A (Mr. Snider) What's stated in the IRP, and I agree with, is that the first capacity need from the '11 IRP to the '12 IRP was shifted from 2015 to 2016 and is primarily due to lower forecasted load projections, an increase in the projected capacity and energy, purchases from qualified facilities pursuant to the requirements of PURPA 1978. And I could go on and on, but yes, in part, that was one of the factors.

Q Ms. Bowman, on page 13, at line 2 of your rebuttal, --

A (Ms. Bowman) Yes.

Q -- you state, "Issues such as the potential impact on spinning reserve and operating reserve requirements of adding a substantial amount of intermittent generation to a utility system are not discussed at all by Witness Rabago." Is that correct?

A (Ms. Bowman) Yes.

Q I would like to try to ask a few questions about this.

A (Ms. Bowman) Okay.

Q Is operating reserve the same thing as or related to the reserve margin?

A (Ms. Bowman) Operating reserve, I believe, is different than the reserve margin. The reserve margin is about installed capacity on the system. Operating reserve margin is what you -- you have available to turn on when needed.

Q Okay. So they're related, but different.

A (Ms. Bowman) That's correct.

Q Does a reserve margin help a utility plan how much capacity it needs?

A (Ms. Bowman) It is a component of how much a utility needs capacity.

Q And I think we've just mentioned this with Witness Snider. QF generation can help a utility defer or even eliminate its need for added capacity; is that correct?

A (Ms. Bowman) Yes. That's what Witness Snider just said.

Q And I think we heard some testimony from Public Staff Witness Ellis about lumpiness. Is it also true that QF solar can be built out less lumpily than something like a nuclear plant or even an 805 MW four-unit CT?

A (Ms. Bowman) Less lumpily, I mean, they can be built quicker, yes, and I suppose they could help out with smoothing of the lumpiness.

Q So solar can help meet capacity needs.

A (Ms. Bowman) Yes.

Q What if Duke has a greater capacity need than it thinks? With its quick build-out time, would solar's value be enhanced in such a situation?

A (Ms. Bowman) I think Witness Snider, who is the Director of the IRP for both DEC and DEP, is in a better position to answer that question.

A (Mr. Snider) Yes. It has a potential to both be a benefit and a source of uncertainty in planning. So, for example, we -- we were planning for many, many MW of wind a couple years ago that never materialized. Had we solely determined that we were not going to build generation depending on the wind forecast and then the wind QFs didn't materialize, we would have found ourselves short capacity. So to the extent it shows up, it is smoother, but you still have to forecast we have 1,700 MW in. Is that going to be 3,400 MW or 300? We have to take that and then build to accommodate the rest. So it's -- on one sense it's smoother, and in another sense it introduces more uncertainty in the planning process.

MR. YOUTH: Commissioner Brown-Bland, I've got some additional questions in this line of questions, but they involve confidential information, so I can either revisit this at the appropriate time, or I don't know that there are many people left that are not on the confidentiality agreement. If everybody in the room is on a confidentiality agreement, I might be able to proceed now.

COMMISSIONER BROWN-BLAND: Is everyone remaining in the room -- well, hold on. Before we do that, I'd prefer to stick with the method that we have been doing, and so we just get through the nonconfidential and come back to the confidential. Is that --

MR. YOUTH: I appreciate that, and I will skip and continue on, then, with public questions.

COMMISSIONER BROWN-BLAND: Do you have much more to go right now with the public questions? If you're near the end, I'll let you complete that. If it's going to take a while, I think this is a good time for a break.

MR. YOUTH: Maybe a break.

COMMISSIONER BROWN-BLAND: All right. Let's try to make this a 10-minute break and be back at 3:40.

(Recess taken from 3:31 p.m. to 3:43 p.m.)

COMMISSIONER BROWN-BLAND: Let's come back on the record. Mr. Youth, you may pick up where you left off.

MR. YOUTH: Commissioner Brown-Bland, I have handed an exhibit, NCSEA Bowman Rebuttal Cross Exhibit 1. If that could be so marked for identification.

COMMISSIONER BROWN-BLAND: Will you state that -- Bowman?

MR. YOUTH: NCSEA Bowman Rebuttal Cross Exhibit Number 1.

COMMISSIONER BROWN-BLAND: All right. It will be so identified.

(Whereupon, NCSEA Bowman Rebuttal Cross Examination Exhibit Number 1 was marked for identification.)

BY MR. YOUTH:

Q Ms. Bowman, on page 10 of your rebuttal testimony, lines 11 through 13, --

A (Ms. Bowman) Sorry. Which page, again?

Q Page 10.

A (Ms. Bowman) Okay.

Q Lines 11 through 13, you state, "First and foremost, the VOS" -- Value of Solar -- "studies that he" -- Mr. Rabago -- "describes are inappropriate for setting avoided cost rates and are irrelevant to the present proceeding." Is that correct?

A (Ms. Bowman) That's correct.

Q As we touched on yesterday, Duke and Progress have initiated a value of solar study. Is that correct?

A (Ms. Bowman) I believe we weren't going to say it was a value of solar study, but we have initiated studies to study the impacts.

Q If you'll take a look at the cross exhibit in front of you, in response to Commission questions in the 2012 IRP proceeding, Duke and Progress submitted a response verified by Mr. Snider that provided, in pertinent part, "The Companies are currently initiating a comprehensive study seeking to identify and, where possible, quantify potential benefits and costs of solar generation across the entire generation, transmission and distribution systems." If you move down a bit, it says, "These study results would be incorporated into the resource planning and avoided cost processes in order to reach the optimal economic solution when building or procuring solar resources." Is that correct?

A (Ms. Bowman) Yes. That's what it says here.

Q And if you look at Duke and Progress' response on this data request, the cross exhibit, does it indicate that Duke and Progress hope to incorporate findings from their solar integration study, as applicable, into the next avoided cost tariff filing in November 2014?

A (Ms. Bowman) Yes. I believe that's what it says.

Q So I will call it a solar integration study, is relevant to avoided cost proceedings. Is that correct?

A (Ms. Bowman) It could be.

Q And correctly valuing solar is particularly important to solar QFs in this proceeding, where the proposed rates have dropped, from their perspective, precipitously. Do you recognize that?

A (Ms. Bowman) I recognize that the rates have dropped. I don't know that I would necessarily say precipitously.

Q And you realize that correctly valuing solar because of the drops is particularly important to solar QFs in this proceeding?

A (Ms. Bowman) Well, I think this proceeding is about setting avoided cost. It's not about quantifying the value of solar facilities. It's about setting avoided costs, which are the costs that a utility avoids when they purchase from a qualifying facility.

Q So I'll rephrase my question. Making sure the avoided capacity payments they are getting are correctly priced is important to solar QFs in this proceeding; is that correct, or do you recognize that concern on their

part?

A (Ms. Bowman) I recognize there is concern, yes.

Q We're about a year out from when these new rates were first proposed; is that correct?

A (Ms. Bowman) Yes. They were proposed in November of 2012.

Q Do you or Mr. Snider know how many MW of projects 5 MW or smaller have been installed and become operational under these new rates?

A (Ms. Bowman) These new rates have not yet been approved.

Q That is true, but that does not answer my question. The rates are available to QFs at this point in time; is that correct, even though they have not been approved?

A (Ms. Bowman) Yes. I believe there is a -- way back in the beginning of the proceeding, an order on suspension of tariffs and a true-up provision for those QFs that filed and requested a CPCN before December 1st.

A (Mr. Snider) Subject to check.

A (Ms. Bowman) Subject to check.

Q I'll ask again, do you know or can you supply an answer to the question, how many MW of solar capacity in the aggregate comprised of QFs 5 MW and less, how many

of those types of projects have been installed and become operational in the last year?

A (Ms. Bowman) I don't know that off the top of my head.

MS. FENTRESS: Madam Chair, we can provide a late-filed exhibit to that -- in answer to that question, if necessary.

COMMISSIONER BROWN-BLAND: Mr. Snider, did you have an answer to that?

MR. SNIDER: Well, I was going to say the same -- I think we've agreed to file a late-filed exhibit, and the only thing I would add to that is I think we've just heard testimony that it takes at least six to nine months to construct these facilities. You would have to then, first of all, procure the land. There's things you do before you construct. So you would not expect a significant amount of actually installed since this -- over this past year if there's -- approaching a year long, but we will provide this information in a late-filed exhibit.

COMMISSIONER BROWN-BLAND: All right. I saw you moving for the mic, but in any case, the Commission will take counsel up on the request for a late-filed exhibit.

BY MR. YOUTH:

Q Is it fair to say, Mr. Snider, based on the response you gave to Commissioner Brown-Bland, that your guess at this point would be that there are not many projects 5 MW and smaller that are actually operational, solar QF projects that are operational at this point in time?

A (Mr. Snider) No. I'm not going to make a guess on that. I guess it's dependent on what you call "many." I think there's many, many more than we had three years ago, but the number relative to the 2,000 MW in the queue is probably still fairly small.

Q Once the Joint Dispatch Agreement is integrated into the 2014 proposed avoided cost rates, we're likely to see rates drop even more, making financing even more difficult for QFs; is that correct?

A (Mr. Snider) You're supposing all other factors equal, and I would say if gas prices do not move -- they are projected to go up -- if they did not and all other factors stayed exactly equal, it would have the effect of lowering the rate.

MR. YOUTH: No further questions, except for the confidential portion.

COMMISSIONER BROWN-BLAND: Right. Ms.

Mitchell?

MS. MITCHELL: Just a few questions.

CROSS EXAMINATION BY MS. MITCHELL:

Q I'm going to direct my question at Witness Bowman since she's referenced in her testimonies the queue of QFs waiting to be developed. And Ms. Bowman, just off the top of your head -- I'm not looking for a specific number, but do you know -- can you give me a percentage of how much of that proposed capacity in the queue is eligible for the standard rates that are approved by this Commission?

MS. FENTRESS: Can I ask for a clarification of that question? Which standard rates do you mean, the ones approved by this Commission. The ones that are currently approved?

MS. MITCHELL: The rates that are approved for the small power producer.

A (Ms. Bowman) I mean, just off the top of my head and, please, nobody hold me to this, but I would say probably 50 percent or so. The reason being, at least in the latest rounds of CPCNs that I've seen filed at the Commission, and I know there were 10 this past Monday on the agenda, they've all been roughly 5 MW or less, I think primarily because they do get the standard rate which has the 1.2 performance adjustment factor in it, but that's just, you know, from my own opinion. Again, don't hold me to that 50 percent, but that's my guess.

BY MS. MITCHELL:

Q So the other 50 percent would be -- would exceed the size threshold for the standard rates? In other words, the other 50 percent would be projects that are in excess of 5 MW?

A (Ms. Bowman) Yes. You are correct.

Q And is it primarily solar capacity that's proposed?

A (Ms. Bowman) Yes.

Q And can you -- again, I'm not looking for a specific number. Just roughly, how much of it is solar? I'm talking about the total capacity proposed at this point.

A (Ms. Bowman) I'll let Mr. Snider take a shot at that.

A (Mr. Snider) I'm going to say roughly 85 to 90 percent.

Q So 85 to 90 percent of what's in the queue is solar?

A (Mr. Snider) Roughly.

Q Okay. And the remainder would be?

A (Mr. Snider) I believe there's some wind and maybe some other small projects that I'm not aware of, but I know there recently have been a couple of wind projects, I believe.

A (Ms. Bowman) And there's a few swine and poultry projects.

Q Okay. How many Power Purchase Agreements has either Duke or Progress entered into with solar facilities that are in excess of 5 MW?

A (Ms. Bowman) I don't have that figure off the top of my head. I mean, it can be provided, but I don't know it.

MS. MITCHELL: I'd like to ask that that be provided in a late-filed exhibit, if that's acceptable to the Commission.

MS. FENTRESS: I think that this hearing is primarily looking at 5 MW of capacity and less. That is what is on our tariffs, and that is the focus of this hearing, so I'm not certain of the relevancy of contracts, negotiated contracts, with QFs that are greater than 5 MW.

COMMISSIONER BROWN-BLAND: Do you object to providing it?

MS. FENTRESS: I object to the relevancy.

COMMISSIONER BROWN-BLAND: Do you want to respond?

MS. MITCHELL: Yes. We've heard a lot over the past day and a half about the proposed capacity in the interconnect queue, and I'm just trying to flush out what's in that queue. All that's appeared in the testimony is just numbers, and I'm trying to determine what types of QFs those are, how big the projects are. Is it primarily smaller power producers? Is it projects that are in excess of 5 MW? That's the nature or the intent of my question.

COMMISSIONER BROWN-BLAND: If you can provide it, I'd request that you provide it. Do you have further questions, Ms. Mitchell?

MS. MITCHELL: So the information to be provided is the number of Power Purchase Agreements entered into with solar facilities in excess of 5 MW?

COMMISSIONER BROWN-BLAND: Yes. And it's the number; it's not the particular. It's just the number.

MS. MITCHELL: Understood.

BY MS. MITCHELL:

Q And Ms. Bowman, you said that 50 percent of the capacity -- you handicapped it at 50 percent -- is 5 MW or smaller. Is that proposed capacity?

A (Ms. Bowman) That is just a guess.
A (Mr. Snider) I would concur with that as a rough estimate.
Q So the remaining solar projects are in excess of 5 MW?
A (Ms. Bowman) Yes, they would be. If they're not under 5, they would be in excess.
Q Okay. I just wanted to clarify.
A (Ms. Bowman) Okay.
Q And it seems if there's that much proposed capacity -- I'm sorry. I'm going to go back and ask you a question again because I don't recall your answer. How many Power Purchase Agreements has the Company entered into with solar facilities in excess of 5 MW?
A (Ms. Bowman) I think we said we did not have the answer to that, and that will be provided.
MS. MITCHELL: Okay. Thank you. No further questions.
CHAIRMAN BROWN-BLAND: All right. Ms. Ottenweller?
MS. OTTENWELLER: Thank you.
CROSS EXAMINATION BY MS. OTTENWELLER:
Q Good afternoon. I would like to clarify something for the record to start out. And I think that

Mr. Snider, these questions will probably be directed to you. Are you familiar with Public Staff Witness Hinton's testimony in this docket?

A (Mr. Snider) Yes.

Q I'd like to refer you to page 2 of his testimony and ask you a couple questions. Just let me know when you're ready.

A (Mr. Snider) Page 2?

Q Yes.

A (Mr. Snider) Okay.

Q Do you recall that Mr. Hinton testified that the PURPA avoided costs established in this proceeding are the same as those used for EE/DSM purposes?

A Can you point me to the line, please?

Q Sure. It's page 2, lines 13 through 18. I can read it if that would help. It says, "In addition to providing the basis for electric power purchases from QFs by a utility, the avoided costs determined by the Commission are utilized in other applications, including the determination of the cost effectiveness of demand-side management and energy efficiency programs and the calculation of performance incentives for such programs."

A (Mr. Snider) Yes. I see that.

Q The PURPA QF avoided cost rates at issue in this docket are based on the marginal cost of capacity and marginal cost of energy, right?

A (Mr. Snider) Correct.

Q Another focus has been on the cost of capacity, but I want to focus on the cost of energy for just a moment. The marginal cost of energy used by DEC and DEP in developing their PURPA QF rates is based on the system lambda, correct?

A (Mr. Snider) No, it is not.

Q It's not. What is it based on?

A (Mr. Snider) It's based on a differential revenue when you run 100 MW of free generation as compared to the system as it exists today, and then you see the value that that 100 MW creates, that 100 MW that includes all energy value from fuel, all SOx and NOx allowance prices, all reagent costs that go into that calculation, including limestone, ammonia, start-up costs that are avoided, et cetera, so it's far more comprehensive.

Q Do DEC and DEP use the same avoided capacity cost as used in the Company's IRP?

A (Mr. Snider) They do not.

Q Do they use the same avoided energy cost?

A (Mr. Snider) Energy cost between what and what?

Excuse me. I'm sorry. Who we're comparing or what we're comparing.

Q For DSM/EE purposes. I'm asking if DEC and DEP use the same avoided energy cost in those proceedings as they do in these avoided cost proceedings.

A (Mr. Snider) Generally, there would be a difference in vintage of the data. I'm not the EE witness, so I can't testify exactly to what vintage they use.

Q Okay.

MS. OTTENWELLER: Just a moment. Okay. Thank you. I believe the rest of my questions pertain to Ms. Bowman.

BY MS. OTTENWELLER:

Q Ms. Bowman, prior to serving in your current position, you led Progress Energy's Legal Regulatory Affairs group and were responsible for FERC legal policy and compliance matters, correct?

A (Ms. Bowman) Yes.

Q How long did you hold that position?

A (Ms. Bowman) This was when -- before the merger, so this was with Progress Energy, so that was back in the 2004, 5, 5-ish timeframe.

Q Prior to that, you were Progress Energy's

attorney for FERC matters for all regulated utilities and unregulated merchant generation operations?

A (Ms. Bowman) Yes. When I first joined CP&L back in 1999, we had merchant plants, and then we merged with Florida Progress and we had Progress Energy Carolinas, Progress Energy Florida, and then we had Progress Ventures, which was our merchant facility, and we had some merchant gas plants down in Georgia.

Q How long were you in that role?

A (Ms. Bowman) Probably until the time that I became over the FERC policy stuff, you know, like 2004-ish time frame, and then it became too much to have all of that on one plate, and then we also sold off our unregulated businesses.

Q So you're familiar with PURPA law and regulations?

A (Ms. Bowman) Generally, yes.

Q Have you read Mr. Rabago's testimony?

A (Ms. Bowman) I have.

Q I'd like to discuss some of the benefits that Mr. Rabago lists in his testimony, and specifically at page 16. You stated in your testimony that energy and capacity costs are appropriate for consideration by this Commission, avoided, right?

A (Ms. Bowman) Yes.
Q Do you agree that FERC also allows consideration of costs associated with line losses?
A (Ms. Bowman) They do.
Q What about the costs that a utility avoids when purchasing from QFs with shorter lead times and the ability to install smaller increments of capacity? Do you agree that PURPA allows the Commission to consider this?
A (Ms. Bowman) Yes. They can consider it, yes.
Q Okay. And you agree PURPA allows consideration of dispatchability, reliability and usefulness of QFs during emergencies? Do you dispute any of those?
A (Ms. Bowman) No, I do not.
Q Okay. And also avoidance of demonstrated environmental costs?
A (Ms. Bowman) I don't know that that's specifically listed in PURPA.
Q I believe that that is something that pertains to a FERC Order. Do you agree that FERC allows consideration of it? I should have worded that differently.
A (Ms. Bowman) Yes.
Q Okay. I'd like to direct you to page 12 of

your rebuttal testimony. So based on your responses, when you state in your testimony on page 12 that Rabago's approach to setting avoided cost extends beyond this Commission's authority to set avoided cost rates, you weren't discussing those benefits that we just went through, right?

A (Ms. Bowman) Repeat the question.

Q On page 12 of your testimony, where you state that Mr. Rabago's approach to setting avoided cost extends beyond this Commission's authority, do you remember stating that?

A (Ms. Bowman) Yes, uh-huh.

Q You weren't referring to the potential avoided costs that we just went through that FERC approves or PURPA allows consideration of.

A (Ms. Bowman) I was referring to the studies and all of the other things that Rabago had in his testimony.

Q Have you reviewed those studies?

A (Ms. Bowman) I have generally looked at them.

Q And is it your understanding that those studies do not incorporate the benefits that we just discussed and that PURPA allows consideration of?

A (Ms. Bowman) I think those studies are outside the scope of this proceeding. I think this proceeding is about setting the avoided cost and the cost that the utility avoids when it purchases from a QF. I don't think that the studies have demonstrated what is necessary to show that the utility is actually avoiding cost. I think if that were to be the case, we'd need to do more in-depth studies looking at the various impacts and benefits, so I don't think that we have shown that that's needed.

Q Ms. Bowman, just to clarify and to go back to the question that I asked you, is it your understanding that none of those studies incorporate any of the benefits that we just went through and that PURPA allows consideration of?

A (Ms. Bowman) Could you repeat the question?

Q Sure. I think I asked it better the first time. Are you saying that the value of solar studies and the value of solar benefits that Mr. Rabago refers to in his testimony, that none of those incorporate the benefits that we just went through that PURPA allows consideration of?

A (Ms. Bowman) Well, Mr. Rabago lists all sorts of benefits, and all sorts of benefits are in the studies, and I'm saying that that laundry list, you know, job retention, economic development, that sort of thing, are not part of what goes into calculating an avoided cost.

Q I understand that, but some of the benefits that he does list on page 16 of his testimony that we just went through, you're not saying that to the extent that those benefits that PURPA allows consideration of, to the extent that those are incorporated into value solar studies, that those are not inappropriate for this Commission to consider?

A (Ms. Bowman) They're not inappropriate for this Commission to consider. I just don't feel like they're appropriate in the context of the avoided cost in this proceeding. There can be other avenues for which to consider some of those benefits, such as in REC pricing and net metering and so forth.

Q So it's your position that the Commission should not consider those benefits, but you're not saying that it's outside of their authority to do so.

A (Ms. Bowman) I think they have that ability to consider it if they choose so.

Q. Okay. Thank you. Just a couple more questions. Ms. Bowman, as a former FERC practitioner, you're aware that PURPA regulations permit this Commission to differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies? Are you aware of that regulation in PURPA?

A (Ms. Bowman) Yes.

Q Okay. I want to ask you a few questions about this. DEC and DEP did not base their avoided energy rates on an hourly profile of solar energy, correct?

A (Ms. Bowman) That is correct.

Q I specifically want to ask you a question about Exhibit KRR-7, and I know that that was just formally admitted as an exhibit today, so we have extra copies of it if anyone needs --

A (Ms. Bowman) I need a copy.

Q Okay.

MS. FENTRESS: Counsel, may I have a copy? We have one at our table, but if you have an extra copy, I'd appreciate it.

MS. OTTENWELLER: May I approach?

COMMISSIONER BROWN-BLAND: Yes.

BY MS. OTTENWELLER:

Q Ms. Bowman, this document is the report by Crossborder Energy that was filed by NCSEA in this docket on October 18, 2013, correct?

A (Ms. Bowman) Yes.

Q Have you reviewed this report?

A (Ms. Bowman) Only briefly.

Q Okay. The overall conclusion of this report was that the benefits of wholesale solar exceeded its cost by about 40 percent, right?

A (Ms. Bowman) That's what the report states.

Q Okay. I'd like to refer you to page 8 of the report. I just have one question on this report. In the second paragraph, and I'll begin with "North Carolina." Are you there?

A (Ms. Bowman) I'm there.

Q Okay. "North Carolina avoided cost prices are differentiated into on- and off-peak prices, and also can vary seasonally by peak versus off-peak months. This differentiation captures some, but not all of the hourly variation in the energy benefits of solar. What is missing is the likelihood that the diurnal profile of solar output will have a higher value than a flat block of on-peak power, because solar output peaks in the early afternoon hours and produces significant power in the mid-afternoon hours of peak demand." Did I read that correctly?

A (Ms. Bowman) Yes.

Q Now, this report found that using the hourly

profile of solar energy allows a more accurate assessment of the energy cost that a utility is able to avoid when it purchases solar during peak times. Do you see that?

A (Ms. Bowman) Yes.

Q **Do you agree that this approach of basing energy rates on the supply characteristics of solar energy is consistent with the PURPA regulation we just discussed?**

MS. FENTRESS: Can I object? I'm not sure Ms. Bowman testified about our energy rates in her rebuttal.

MS. OTTENWELLER: But she did state that she believes that under PURPA, it's appropriate to consider both the energy and capacity avoided cost, and so I'm just asking her. Mr. Snider is welcome to answer this, too, if that would be helpful for the witness.

A (Mr. Snider) It would be a consideration in future filings. It's not how rates have been done, nor have they been proposed, nor do we have any evidence in this proceeding that they should be calculated in that manner.

BY MS. OTTENWELLER:

Q **Right. I'm not actually asking about whether you agree that the approach should be adopted; I'm just asking about whether you agree that the approach that's**

taken here is permitted under PURPA based on a regulation that we just discussed.

A (Ms. Bowman) Well, it's a completely different concept of calculating avoided cost than what we have done historically here in North Carolina and what has been filed in this proceeding, but it's something that if the Commission wants to take up, they certainly can.

Q **Okay. Thank you. Just a couple more questions. Duke did not study whether distributed wind or solar QFs allow the utilities to avoid additional transmission or distribution costs compared to purchases from other facilities, correct?**

A (Ms. Bowman) No.

Q **Nor did Duke study whether distributed solar or wind QFs allow utilities to avoid additional line losses?**

A (Ms. Bowman) No.

MS. OTTENWELLER: Thank you. No further questions.

COMMISSIONER BROWN-BLAND: Any redirect?

MS. FENTRESS: Yes. Thank you.

REDIRECT EXAMINATION BY MS. FENTRESS:

Q **I'll start with you, Ms. Snider. I believe that Mr. Youth was asking you about the 700 MW of solar that is listed in our IRP. Do you remember that**

question?

A (Mr. Snider) I do.

Q **Yes. And can you tell us, how did we end up with 700 MW of solar in our IRP?**

A (Mr. Snider) That was done as a part of our REPS compliance strategy. When we went to our renewable group and asked them what their forecasted plan was to comply with Senate Bill 3 and North Carolina REPS, they produced a forecast that included that 1,700 MW of installed, which gives us the equivalent utility capacity of about 700 MW.

MR. YOUTH: I just want to clarify. I did not ask about 700 MW of solar. It was that, I think, Mr. Snider testified that 1,689 MW of solar would essentially help meet 700 MW of peak demand.

MS. FENTRESS: You asked about the IRP; is that correct?

MR. YOUTH: Yes, but it was not 700 MW of solar, is the only thing I want to clarify.

BY MS. FENTRESS:

Q **Well, with that clarification, Mr. Snider, do you need to change your answer in any way?**

A (Mr. Snider) One second, please. I actually responded with respect to solar.

Q Thank you. And if you have wind or solar in your planning and it winds up being unavailable, what does the utility have to do to account for that?

A (Mr. Snider) Use alternate resources or purchase alternate resources.

Q Thank you. Ms. Bowman, this question is for you. I believe Mr. Youth, or it may have been Ms. Mitchell, asked you about our avoided cost rates in 2010. Do you remember that question?

A (Ms. Bowman) Yes.

Q And I believe the question was isn't it a fact that our avoided cost rates are lower now in 2012, our proposed avoided cost rates are lower now than the ones approved in 2010. Is that correct?

A (Ms. Bowman) Yes.

Q And what would you say was the largest driver for the decline in avoided cost rates from 2010 to 2012?

A (Ms. Bowman) It was the price of fuel. Fuel has gone down.

Q And in your opinion, is it appropriate to use the performance adjustment factor to adjust payments of capacity cost upward to offset a naturally occurring decline in avoided energy rates?

A (Ms. Bowman) No. It's not a good means to use a performance adjustment factor for that.

MS. FENTRESS: That's all I have.

COMMISSIONER BROWN-BLAND: All right. Anyone now who has not signed on to the nondisclosure agreement -- do you still want to ask your --

MR. YOUTH: In the interest of time, I'm going to forego my questions. I know we've got some issues on Dominion and we're running late.

COMMISSIONER BROWN-BLAND: Okay. Then everyone can stay put. Are there questions from the Commission for these two witnesses on rebuttal?

(No response.)

MS. FENTRESS: May I admit his exhibits into the record, please, and those exhibits would be Mr. Snider's four exhibits.

COMMISSIONER BROWN-BLAND: Yes. Those exhibits will be admitted without objection and entered into the record as evidence.

(Whereupon, Rebuttal Exhibits GAS-1 and GAS-3 were admitted into evidence. Confidential Rebuttal Exhibits GAS-2 and GAS-4 were admitted into evidence and filed under seal.)

COMMISSIONER BROWN-BLAND: These two witnesses are excused.

(Witnesses excused.)

COMMISSIONER BROWN-BLAND: All right. Dominion?

MS. KELLS: We'd like to call Mr. Bruce Petrie and Mr. Robert Trexler as a panel, please.

DIRECT EXAMINATION BY MS. KELLS:

Q Mr. Trexler, I'll start with you. Did you cause to be prefiled in this docket on October 18, 2013, the rebuttal testimony of Robert J. Trexler on behalf of Dominion North Carolina Power, consisting of 14 typed pages of questions and answers, and an exhibit RJT-1?

A (Mr. Trexler) Yes.

Q Was that document prepared by you or under your supervision?

A (Mr. Trexler) Yes.

Q Do you have any corrections to that document?

A (Mr. Trexler) Yes, I do. On page 1, line 12 of my rebuttal testimony, the Roman Numeral VI should be a Roman Numeral V. Also, on page 3, line 15, the Docket No. reference should read E-100 rather than E-22.

Q With those revisions, would your answers to the questions in your rebuttal testimony be the same if you were asked those questions today?

A (Mr. Trexler) Yes.

Q **And are they true and correct, to the best of your knowledge?**

A (Mr. Trexler) Yes.

MS. KELLS: Commissioner, I move that the prefiled rebuttal testimony of Mr. Trexler be copied into the record as if given orally from the stand, and ask that his Exhibit RJT-1 be marked for identification.

COMMISSIONER BROWN-BLAND: That motion is allowed, and the exhibit will be so identified.

(Whereupon, the rebuttal testimony of Robert J. Trexler, as corrected, and Appendix A was copied into the record as if given orally from the stand.)

REBUTTAL TESTIMONY
OF
ROBERT J. TREXLER
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 136

Q. **Please state your name, business address, and position of employment.**

A. My name is Robert J. Trexler, and my business address is 701 East Cary Street, Richmond, Virginia 23219. My current position is Director of Regulation for Dominion North Carolina Power ("DNCP" or the "Company"). Prior to October 1, 2013, I was the Director of Power Contracts for the Company. My responsibilities as Director of Power Contracts included the negotiation (including restructuring) and day-to-day administration of the Company's non-utility generation power purchase contracts. A statement of my background and qualifications is attached as Appendix A.

Q. **Have you filed other documents, comments or testimony in this proceeding?**

A. Yes, I sponsored Sections I, IV and VI of the Company's Comments, Exhibits and Avoided Cost Schedules, filed in this docket on November 1, 2012. In addition, I filed direct testimony on August 9, 2013 and have participated in responding to data requests of other parties to this proceeding.

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

A. The purpose of my rebuttal testimony is to describe Article 6 of DNCP's Agreement for the Sale of Electrical Output to Virginia Electric and Power

Company with regard to the Company's Schedule 19-FP (the "Schedule 19-FP PPA") and to respond to the affidavit of Mr. Erik Stuebe and the testimony of Mr. John E. P. Morrison with respect to Article 6 of the PPA. In addition, I will respond to certain aspects of Mr. Morrison's testimony on the relationship of QF financing and avoided costs.

Q. Please describe Article 6 of the Schedule 19-FP PPA.

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

Q. Does the Regulatory Disallowance Clause give this Commission or the Company the right to disallow recovery of avoided costs rates or adjust the rates approved by this Commission in this proceeding?

A. No, the Regulatory Disallowance Clause does not itself give the Commission or the Company the right to disallow recovery of or adjust avoided costs payments made pursuant to Schedule 19-FP, and the Company would contest any such disallowance. Further, Article 6 does not give the Company the right to seek a Disallowance Order. The Company believes that QFs should receive full payments under a PPA and the Company should receive full rate recovery of those payments. Article 6 simply recognizes that neither the Company nor a QF can control the actions of a regulatory body and allocates the burdens of a Disallowance Order equitably if such an order is issued and held to be lawful.

Q. **Is the Regulatory Disallowance Clause a new addition to DNCP's Schedule 19 Contracts?**

A. No, the Commission has approved standard Schedule 19 PPAs containing a clause similar to the Regulatory Disallowance Clause since at least 1997.[1]

Q. **Has the Commission recently ruled on the reasonableness of the Regulatory Disallowance Clause?**

A. Yes, in the previous biennial proceeding, Docket No. E-22, Sub 127, the Commission held that, based on the record in that proceeding, DNCP's inclusion of the same Regulatory Disallowance Clause in its Schedule 19-DRR PPA was "reasonable and should be allowed."[2]

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[1] *See, e.g., In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 1996*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 23, Docket No. E-100, Sub 79 (June 19, 1997) (approving the standard contracts proposed by DNCP as reasonable).

[2] *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2010*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 22, Docket No. E-100, Sub 127 (July 27, 2011).

Q. Why does the Company believe that the inclusion of the Regulatory Disallowance Clause is reasonable and necessary?

A. Basically, the Company believes that inclusion of the Regulatory Disallowance Clause is a matter of fundamental fairness.

Q. Please explain.

A. The Company's purchase of energy and capacity from QFs is not optional. Currently, pursuant to PURPA, and the rules, regulations and orders of this Commission, the VSCC and FERC, the Company has a mandatory obligation to purchase energy and capacity from QFs of 20 MW or less at the Company's avoided cost.[3] Without the Regulatory Disallowance Clause, if there were a Disallowance Order, the Company would be required to continue making full payments to the QF but would not be compensated for the portion of those payments in excess of the Disallowance Order amount. The Company believes there is no principled reason that the burden of the disallowance of legally compelled payments should be borne by the Company and its shareholders.

Q. Does the fact that the Commission will have expressly approved the Schedule 19 rates in this proceeding have any bearing on the need for a Regulatory Disallowance Clause?

A. No, but it does tend to lessen the risk of a Disallowance Order. There is precedent for the proposition that a regulatory commission cannot revise avoided cost rates that it has previously reviewed and approved. *See, e.g.*, *Freehold Cogeneration Associates v. Bd. of Regulatory Commissioners of New Jersey*, 44 F.3d 1178, 1194 (3d Cir. 1995), *cert. denied*, 516 U.S. 815 (1995) (holding that once a state regulatory commission approved a power purchase agreement between a QF and a utility on the ground that the agreement's rates were consistent with avoided cost, the commission was preempted by PURPA from reconsidering its approval). However, the possibility still exists that avoided cost rates approved by one regulatory body could be rejected by another regulatory body. While the Company certainly would resist such a result, it is a possibility, and has occurred before as I discuss below.

Further, the Company notes that in North Carolina, avoided cost rates for QFs larger than five MW are not reviewed and approved by the Commission and therefore do not enjoy the relative assurance of Commission-approved rates. Accordingly, any decision by the Commission to require removal of Article 6 from the Schedule 19 PPAs would not and should not apply to contracts that are not eligible for Schedule 19 (e.g., those contracts pertaining to QFs larger than five MW).

[3] The Company has been relieved of its obligation to purchase energy and capacity from QFs with a net capacity of greater than 20 MW. *See Virginia Electric and Power Company*, 124 FERC ¶ 61,045 (2008).

Q. Does the Company believe that the risk of the issuance Disallowance Order is substantial?

A. No. The Company believes that the possibility of a Disallowance Order is remote under existing law and precedent. Presumably, QFs and their lenders are also aware of the relatively low risk of a Disallowance Order and therefore can be reasonably certain of the return on their investment.

Q. If the risk of a Disallowance Order is remote, then why does the Company believe that the inclusion of a Regulatory Disallowance Clause is nonetheless necessary and reasonable?

A. Because, while remote, the risk of a Disallowance Order is real. In 1993, this Commission disallowed North Carolina rate recovery of a portion of the Company's avoided cost payments to three Virginia QFs because it concluded that the avoided cost payments ordered by the VSCC exceeded DNCP's avoided costs. *See Ex rel. Utilities Commission v. North Carolina Power*, 338 N.C. 412, 416, 450 S.E.2d 896, 898-899 (1994), *cert. denied*, 516 U.S. 1092 (1996) ("*Utilities Commission v. North Carolina Power*"). Similarly, the VSCC has disallowed recovery of a portion of payments to QFs when it subsequently determined that the avoided costs under the QF contracts erroneously included costs that were not in fact avoided costs. *See Hopewell Cogeneration Limited Partnership v. State Corporation Commission*, 249 Va. 107, 118-119, 453 S.E. 277, 284 (1995), *cert. denied*, 516 U.S. 817 (1995).

Q. Have you reviewed the affidavit of Mr. Erik Stuebe and the testimony of Mr. Morrison as they relate to the Regulatory Disallowance Clause?

A. Yes.

Q. What does Mr. Stuebe say about Article 6 of the Schedule 19-FP PPA?

A. Mr. Stuebe states that Ecoplexus, Inc. ("Ecoplexus") has multiple five MW solar QF projects under development in the Company's North Carolina service territory and that he has been involved in attempting to secure financing for these projects. Mr. Stuebe further states that he has sought financing from two lenders for these Ecoplexus projects, one of whom has previously financed Ecoplexus projects in other states.

Mr. Stuebe states that the two lenders that he has approached have declined to finance Ecoplexus' proposed QFs because of Article 6 of the Schedule 19-FP PPA. Further, he states that based on this experience, "Article 6 constitutes a barrier to finance." Affidavit of Erik Stuebe at 2, Docket No. E-100, Sub 136 (Sept. 27, 2013).

Q. Do you have comments on Mr. Stuebe's statements?

A. Yes. First, two lenders do not constitute the universe of potential lenders or sources of financing to Ecoplexus' proposed facilities. The Company has entered into a number of QF contracts containing Article 6 and those QFs have seemingly managed to finance their facilities, which I will discuss further below. Finally, I am aware of no requirement under PURPA that the Company or this Commission modify their respective avoided cost policies based on the demands of a QF's lenders, which I also will discuss further below.

Q. What does Mr. Morrison say about Article 6 of the Schedule 19 PPA?

A. Mr. Morrison, chief operating office of Strata Solar, LLC ("Strata") a large QF solar developer, testified that the Regulatory Disallowance Clause created uncertainty that "is a barrier to financing a QF project, as investors are unwilling to overlook the asserted right of DNCP to modify rates and collect a refund." Direct Testimony of John E. P. Morrison at 11, Docket No. E-100, Sub 136 (Sept. 27, 2013) ("Morrison Testimony"). In addition, Mr. Morrison testified that in Order No. 69, FERC stated that "in order to be able to evaluate the financial feasibility of a [QF], an investor needs to be able to estimate, with reasonable certainty, the expected return on potential investment before the construction of a facility. *Id.* at 12 (citation omitted). Mr. Morrison believes that the Regulatory Disallowance Clause "creates unnecessary uncertainty regarding an investor's expected return on a potential investment, in what appears to [him] to be a violation of Order No. 69." *Id.*

Mr. Morrison also asserted that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA. *See id.*

Finally, Mr. Morrison testified that Strata has not developed solar facilities in the Company's service territory because of the Regulatory Disallowance Clause. *See id.*

Q. Do you agree with Mr. Morrison's assertion that the Regulatory Disallowance Clause gives the Company the right to modify rates and collect a refund?

A. No. The Company is not "asserting a right" to modify rates paid to QFs. As I explained above, the Regulatory Disallowance Clause does not give the Company, or the Commission, the right to modify PPA rates. The clause simply recognizes that neither the Company nor a QF can control the actions of a regulatory body and allocates the burdens of a Disallowance Order equitably if such an order is issued and held to be lawful.

Q. Do you have any comments on Mr. Morrison's statement with regard to Order No. 69?

A. Yes. I agree with Mr. Morrison's general proposition that a QF investor, like any other investor "needs to be able to estimate, with **reasonable certainty**, the expected return on potential investment before the construction of a facility." (emphasis added). However, I am unaware of any provision in PURPA that requires that QF investors, unlike other investors, be entitled to absolute certainty of a return on their investment. Moreover, I believe that an investor in Schedule 19-FP QF has a "reasonable certainty" with respect to its investment, because, as I discuss above, under existing law and precedent, the possibility of a Regulatory Disallowance Order is remote.

Finally, if the QF and its lenders will not accept the remote but real risk of a Disallowance Order, why should the entire risk be shifted to the Company and its shareholders? The Company must comply with the legal mandate to purchase power from QFs. The Company must also comply with a Disallowance Order that is held to be lawful. There is no principled reason or basis in PURPA for the Commission to impose the entire burden of a Disallowance Order on the Company and its shareholders under those circumstances.

Q. Do you agree with Mr. Morrison that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA?

A. No. Under the Schedule 19 PPA, a QF is entitled to receive fixed rates over the term of the PPA. Absent the occurrence of a breach of the PPA by the QF, the QF's entitlement to those rates would be affected only if there is a Disallowance Order that is found to be lawful after appeal by the Company and the QF. To be found lawful, a court would almost certainly have to find that a disallowance was not barred by 18 C.F.R. § 292.304(d)(2).

Q. Do you have any comment on Mr. Morrison's testimony that Strata has not developed any solar facilities in the Company's service territory?

A. Yes. Although to my knowledge, Strata has not built a solar facility in the Company's North Carolina service territory, in September and October of this year, two Strata affiliates have filed CPCN applications for solar facilities in the Company's service territory that states that the developer intended to sell power to the Company.[4] Further, the Company has been in discussions with Strata concerning a possible PPA for a solar facility larger than 5 MW in the Company's North Carolina service territory.

Q. Mr. Morrison testified that the Regulatory Disallowance Clause discourages QF development in the Company's North Carolina service territory. Do you agree?

A. No. In the last two years, the Company has entered into five Schedule 19 contracts with QFs, of which three have entered commercial operation and two have started construction. Each of these contracts contained the Regulatory Disallowance Clause at issue in this proceeding. In addition, the Company has entered into a PPA with a 20 MW QF that also contains a provision similar to the Regulatory Disallowance Clause. Perhaps more significantly, so far this year, at least 44 QF projects, representing over 370 MWs of nameplate capacity, have filed applications for certificates of public convenience and necessity for facilities in the Company's North Carolina service territory; nearly all of which are for solar facilities. A list of these QFs is provided at Exhibit RJT-1 to this rebuttal testimony. In short, even with the inclusion of Article 6 in the Company's Schedule 19 and non-Schedule 19 PPAs, there appears to be strong and active interest in the development of QFs in the Company's North Carolina service territory.

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[4] *See In the Matter of Williamston West Farm, LLC For a Certificate of Public Convenience and Necessity and Registration as a New Renewable Energy Facility*, Application at 3, Docket No. SP-2971, Sub 0 (Sept. 18, 2013), *In the Matter of Application of Parmele Farm, LLC For a Certificate of Public Convenience and Necessity and Registration as a New Renewable Energy Facility*, Application at 3, Docket No. SP-3024, Sub 0 (Oct. 3, 2013).

Q. **On pages 4 through 7 of this testimony Mr. Morrison emphasizes that under PURPA a utility is required to purchase energy and capacity at the utility's full avoided costs in order to encourage the development of QFs. Do you agree?**

A. I am not a lawyer, so I cannot speak to Mr. Morrison's legal analysis, but I agree with the general proposition that FERC determined that a requirement that utilities purchase QF power at avoided costs would encourage the development of QFs. Utilities, however, are not required to pay more than avoided costs to encourage QF development.

Q. **What are avoided costs?**

A. Avoided costs are defined under PURPA as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2013).

Q. **Is a utility required under PURPA or FERC's regulations implementing PURPA to pay QFs more than its avoided cost in order to encourage the development of QFs?**

A. No. The FERC regulations implementing PURPA provide that an electric utility is not required to "pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a) (2013).

Q. Did you review Mr. Morrison's testimony on the importance of the internal rate of return (IRR) in financing QF projects?

A. Yes. On pages 10 and 11 of his testimony, Mr. Morrison stated that IRRs in the range of 8% to 12 % are necessary to attract investors. Further, Mr. Morrison testified that based on his experience, the avoided costs rates approved in Docket No. E-100, Sub 127 produced an IRR in that range, but "[a] 20% decrease in rates, as proposed by the Utilities will drop IRRs below that threshold." Morrison Testimony at 10-11.

Q. What did Mr. Morrison predict would be the result if the Commission adopted the avoided cost rates proposed by the Utilities in this proceeding?

A. He stated that he believed that many QF developers would cease to do business in North Carolina. Further, he noted some QF developers, including Strata, were investigating development opportunities in other states in light of utilities' proposed avoided cost rates. Morrison Testimony at 11.

Q. Do you have any comment on Mr. Morrison's prediction?

A. I take Mr. Morrison at his word that Strata would consider abandoning North Carolina solar development if the Utilities' avoided cost rates approved by the Commission do not provide an IRR acceptable to Strata. As I testified above, however, CPCN filings in the Company's North Carolina service territory in the past year indicate strong QF interest in the rates proposed by the Company in this proceeding.

Q. In light of the threat that QF developers would abandon North Carolina, would it be appropriate for the Commission to augment the Utilities' actual avoided costs to reach an IRR level satisfactory to QF developers?

A. No. The purpose of this proceeding is solely to objectively determine the utilities' avoided costs pursuant to and in accordance with PURPA. The rate of return required by QF developers is not an avoided cost and is not relevant to the determination of avoided costs. As the Commission has succinctly stated: "[a] utility is obligated to pay QFs the utility's avoided cost, but it is not obligated to any more than that in order to make a particular QF proposal economically viable." *In the Matter of Economic Power & Steam Generation, LLC v. Virginia Electric and Power Company,* Order on Arbitration at 6, Docket No. SP-467, Sub 1 (June 18, 2010).

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

APPENDIX A

**BACKGROUND AND QUALIFICATIONS
OF
ROBERT J. TREXLER**

I am the Director of Regulation for Virginia Electric and Power Company in Richmond, VA, where I have a responsibility for negotiation and administration of the Company's wholesale and large customer sales contracts. I have a B.S. degree in Electrical Engineering from The Pennsylvania State University. I joined Dominion Virginia Power in January 1986, and have held various positions since joining the Company. Those positions have included engineering and planning positions within various departments in the electric transmission and distribution side of the Company. I joined Dominion Virginia Power's Capacity Acquisition group in January 2002, where I have coordinated the Company's solicitations for non-utility generation and administered a number of the Company's contracts with non-utility generators ("NUGs") and wholesale customers until I became Manager of Wholesale Power Contracts in December, 2007. In that position, I managed the activities of a number of contract administrators managing the Company's Wholesale Power Sales contracts. In April, 2010, I became Director of the Power Contracts Group, where I oversaw both the administration and operational aspects of the Wholesale sales and NUG power purchase contracts. On October 1, 2013, I became Director of Regulation.

(Whereupon, Exhibit RJT-1 was identified as premarked.)

BY MS. KELLS:

Q **Mr. Trexler, do you have with you a summary of your rebuttal testimony?**

A (Mr. Trexler) I do.

Q **Would you please give it now?**

A (Mr. Trexler) In my rebuttal testimony, I describe Article 6 of Dominion's proposed power purchase agreement or PPA for Schedule 19-FP and respond to the affidavit of Mr. Erik Stuebe and the testimony of Mr. John Morrison regarding Article 6. I also respond to certain aspects of Mr. Morrison's testimony on the relationship of QF financing and avoided costs.

As explained in my rebuttal, Article 6 of the proposed Schedule 19-FP PPA is intended to address situations where a regulatory commission issues an order that prohibits Dominion from recovering in rates the payments it has made to a QF and/or requires Dominion to refund to ratepayers the payments it has already made to a QF. This regulatory disallowance clause does not give the Commission nor the Company any right to disallow recovery of avoided cost payments or adjust those payments. Rather, it provides that in the event of such an order that is found to be lawful, the rates provided under the PPA will be reset on a prospective basis at levels that the Company is allowed to recover in rates. It also provides that if the order requires Dominion to refund previous QF payments to its ratepayers, the QF must refund those amounts to Dominion.

Since at least 1997, Dominion has included this clause or one similar to it in its Schedule 19 PPAs, and those PPAs have been accepted by this Commission as reasonable. In the previous biennial proceeding, the Commission specifically held that the regulatory disallowance clause was reasonable and should be allowed.

While unlikely, the risk of a disallowance order is real. Dominion has twice been disallowed recovery of such costs, once by this Commission and another time by the Virginia State Corporation Commission. Due to these experiences, we believe that it is necessary to include Article 6 in the PPA in the case where a disallowance order is issued and is found to be lawful.

In the event of such a disallowance, the Company believes that there is no principle reason that the burden of the disallowance should be borne by the Company and its shareholders. The Company has a legal obligation to purchase energy and capacity from QFs. Because these purchases are required by law, without Article 6, in the event of a disallowance order, Dominion would be required to continue making full payments to the QF, but would not be able to recover the portion of those payments that exceeded the amount permitted by the order. In that event, the Company and its shareholders would bear the full burden of these unrecoverable costs, an inequitable result, given that the purchases themselves are mandated by law.

REG witness Mr. Morrison testified that a certain level of internal rate of return is needed to attract investors to QF projects, and that the rates proposed in this proceeding do not produce returns in that range. As discussed in my rebuttal testimony, the purpose of this proceeding is to determine the utilities' avoided costs pursuant to PURPA. The rate of return required by QF developers or a lender is not an avoided cost. Mr. Morrison also suggested that QF developers are exploring development opportunities in other states due to the utilities' proposed rates here. As my rebuttal testimony explains, based on the number of CPCN applications for solar QFs in our service territory filed this year alone, and the fact that Dominion has successfully entered into multiple QF contracts that include Article 6 with developers who have obtained financing for their projects, Dominion believes that there is a healthy level of interest in QF development and in the rates Dominion has proposed in this case.

Thank you. This concludes my summary of my rebuttal testimony.

Q Mr. Petrie, did you cause to be prefiled in this docket on October 18, 2013, a public version of the rebuttal testimony of Bruce E. Petrie on behalf of Dominion North Carolina Power, consisting of 16 typed pages of questions and answers, and a confidential version of the same rebuttal testimony?

A (Mr. Petrie) Yes, I did.

Q Was that document prepared by you or under your supervision?

A (Mr. Petrie) It was.

Q Do you have any corrections to that document?

A (Mr. Petrie) No.

Q Would your answers to the questions in your rebuttal testimony be the same if you were asked those questions today?

A (Mr. Petrie) Yes.

Q Are they true and correct, to the best of your

knowledge?

A (Mr. Petrie) Yes.

MS. KELLS: Commissioner, I move that Mr. Petrie's rebuttal testimony be copied into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: The motion is allowed, and the rebuttal testimony of Bruce E. Petrie will be received into evidence as if given orally from the stand.

(Whereupon, the public version of the prefiled rebuttal testimony of Bruce E. Petrie was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

FILED
OCT 1 8 2013
Clerk's Office
N.C. Utilities Commission

**REBUTTAL TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 136
REDACTED VERSION**

Q. **Please state your name, business address, and position of employment.**

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am the Manager of Generation System Planning for Dominion North Carolina Power ("DNCP" or the "Company"). My responsibilities include forecasting total system fuel and purchased power expenses, and forecasting the Company's long term avoided costs. A statement of my background and qualifications is attached as Appendix A.

Q. **Have you filed other documents or comments in this proceeding?**

A. Yes. I prepared Section III of the Company's Comments, Exhibits and Avoided Cost Schedules, filed in this docket on November 1, 2012. In addition, I filed direct testimony on August 9, 2013 and have participated in responding to data requests of other parties to this proceeding.

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

A. I will respond to the direct testimony of Mr. John R. Hinton and Mr. Kennie D. Ellis filed on behalf of the Public Staff, the direct testimony of Mr. Don C. Reading filed on behalf of the Renewable Energy Group ("REG"), and the direct testimony of Mr. Karl Rábago filed on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

Q. **What did Mr. Hinton conclude about the inputs used in the Company's avoided energy cost estimate?**

A. Mr. Hinton testified that the inputs used to calculate avoided energy costs by all of the utilities involved in this proceeding were reasonable and were consistent with the inputs and assumptions used by the utilities in their IRPs. Hinton Testimony at p. 6. I agree with this assessment as it relates to the Company. I have not reviewed the inputs and assumptions used by DEC and DEP but have no reason to doubt his conclusion with respect to those companies.

Q. **Did Mr. Hinton testify about the avoided capacity cost estimates filed by DNCP in this proceeding?**

A. Yes. Mr. Hinton's testimony focused on the Company's estimated installed costs of a CT.

Q. **What are the Company's estimated costs of a CT used for this proceeding.**

A. As discussed in more detail in my direct testimony, the Company's nominal installed cost of a CT is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, exclusive of financing costs, and was based on the installed costs of a CT contained in the Company's 2012 IRP.

Q. What did Mr. Hinton say about the Company's estimated cost of a CT used for this proceeding.

A. He testified that he was "comfortable with DNCP's projected installed costs of a CT…." Hinton Testimony at p. 10. However, Mr. Hinton also testified that he believed that DNCP's installed CT cost estimate should include "land cost" even though the Company intends to install CTs at brownfield sites. *Id.* at p. 28.

Q. Do you agree with Mr. Hinton that the estimates of installed CT costs should include land costs, even if the Company's next CT build is expected to be on a brownfield site?

A. No. As I discussed in my direct testimony, the Company's 2012 IRP shows the addition of 400 MW of CT capacity in both 2021 and 2022. *See* Dominion North Carolina Power's and Dominion Virginia Power's Report of its Integrated Resource Plan at 6, Fig. 1.4.1, Docket No. E-100, Sub 137 (Aug. 31, 2012). The Company has multiple existing brownfield sites available where there is adequate land and where the site configuration would allow the addition and build-out of at least 800 MW of CT units. Accordingly, the Company would install the 800 MW of CTs included in the IRP on such brownfield sites. Because the CTs will be installed on brownfield sites, the Company will neither incur nor avoid any land or other greenfield related cost for the CTs.

Q. Is an installed CT cost based upon a brownfield installation consistent with the Company's 2012 IRP?

A. Yes, the Company's installed CT cost estimate was premised on a brownfield installation because that is in fact where the Company plans to install any new CTs.

Q. Has the Public Staff stated its position as to whether consistency between a utility's IRP and the inputs to its avoided cost estimates is important?

A. Yes. In its Reply comments in this proceeding, the Public Staff stated "[i]t is important that the projected CT costs used in the utilities' respective IRPs and generation expansion plans be consistent with the CT costs and assumptions used in the determination of their avoided cost rates." Public Staff Reply Comments at 4. Further, speaking in this instance of energy costs, in his direct testimony Mr. Hinton testified that "it is important that the inputs used in the avoided costs model and the inputs used in the IRP model be consistent." Hinton Direct at 6-7.

Q. Do you agree that consistency with the IRP is important?

A. Yes. The Company agrees that, absent an after-the-fact discovery of error or a demonstrated change in circumstances from those contemplated in an IRP, the inputs and assumptions of the IRP should be used in the determination of avoided cost rates. The Company's installed cost estimate of a CT is consistent with its 2012 IRP. The Public Staff's proposed modification to the Company's installed cost estimate is not.

Q. Would inclusion of land and other greenfield related costs for a CT on a brownfield site be consistent with PURPA?

A. No. Avoided costs are defined under PURPA as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2013). Further, avoided costs must be "just and reasonable to the electric consumer of the electric utility and in the public interest" and an electric utility is not required to "pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a) (2013).

Because the Company would not incur any land costs associated with CTs on a brownfield site, the avoided land costs for such CTs are $0. Requiring the Company's ratepayers to bear costs that are not in fact avoided is not just and reasonable. In other words, requiring the Company to pay capacity rates that include an allowance for land costs that are not avoided will result in the Company paying more than its avoided costs for capacity in violation of PURPA.

Q. Could the Company's plans to install CTs at brownfield sites change, and if so, would that result in the avoided cost capacity rates in this proceeding being too low?

A. In theory, yes. However, it is also possible that the Company will not need or install all of the CTs identified in the 2012 IRP, which would result in the avoided cost rates approved in this proceeding being too high. The point is that in calculating estimates of avoided cost, the Company uses the best information available at the time of the estimate. And when relying on estimates for long-term avoided cost purchases, "the rates for such purchases do not violate [FERC's PURPA regulations] if the rates for such purchases differ from avoided costs at the time of delivery." 18 C.F.R. § 292.304(b)(5) (2013).

Q. Have you quantified the increased costs to the Company and its ratepayers of the use of greenfield CT costs?

A. I quantified those impacts in detail on pages 6 through 8 of my direct testimony. In summary, use of a greenfield CT in lieu of a brownfield CT would increase the installed cost of a CT by $43/kW over the Company's estimate, which would result in an increase in capacity rates by approximately 12.2% above the Company's forecasted avoided cost of capacity.

Q. On page 28 of his testimony, Mr. Hinton states that in Docket No. E-100, Sub 87, the Commission required DNCP and DEC to include the cost of land in their calculation of CT costs. Does the Commission decision in that case require the inclusion of land and other greenfield related costs in this proceeding?

A. No. As explained in more detail in my direct testimony at pages 4 and 5, and in the Company's Reply Comments filed in the Sub 87 proceeding, *DNCP Reply Comments* at 2, Docket No. E-100, Sub 87 (Feb. 2, 2001), DNCP's CT installed cost estimates were based on the Ladysmith CT units 1-2 being installed at a greenfield site. As the Commission noted in the Order in that proceeding,

> NC Power . . . agreed land costs should be included in the

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

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2000, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 12, Docket No. E-100, Sub 87 (Apr. 6, 2001). The Commission adopted "NC Power's agreement to include land costs in its capacity credits, and conclude[d] that NC Power should be required to include the capital costs of land in its calculation of capacity credits for purposes of this proceeding." *Id.* at 12-13 (emphasis added).

As discussed above, the Company has multiple existing sites available to install the 800 MW of CTs identified in its 2012 IRP and the Company would install those CTs on brownfield sites. This is exactly the circumstance that the Company described in Docket E-100, Sub 87: when new capacity will be added at existing sites, "land costs cannot be avoided." This is analogous to prior Commission decisions holding that the Company was not required to offer capacity credits to QFs during periods when the Company in fact had no capacity needs.[1] In those cases, the Commission recognized that no capacity credit should be offered where no capacity costs were avoided. Here, the

[1] *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 1998*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 6, 16, Docket No. E-100, Sub 81 (July 16, 1999); *see also See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 1996*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 8, 21-22, Docket No. E-100, Sub 79 (June 19, 1997), *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 1994*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 8, 27, Docket No. E-100, Sub 74 (June 23, 1995) ("1994 Biennial Order").

Commission also should not require DNCP to pay for land and other greenfield related costs that will not be avoided.

Q. On pages 28-29 of his testimony, Mr. Hinton refers to the CT cost study by the Brattle Group. Do you have any comments about the appropriateness of using that study or any other generic third party study in this avoided cost proceeding?

A. I do not think it is appropriate to rely on the Brattle Report to set avoided cost rates in this proceeding. The purpose of this proceeding is to make utility-specific determinations of the costs that will be avoided by each utility through the purchase of energy and capacity from QFs based on the particular circumstances and plans of each utility. The Brattle Report is simply not an estimate of DNCP's, or any other North Carolina utility's, cost to install a CT, but rather a generic study based on data, given its August 2011 submittal date, that is well over two years old.

Q. What was Mr. Hinton's ultimate recommendation to the Commission with respect to the Company's installed CT cost?

A. On page 30 of his testimony, Mr. Hinton recommended that an installed cost of $650 per kW be used for this proceeding. He also testified that installed CT cost estimates in the range of $625 to $675 per kW were reasonable.

Q. Do you agree with Mr. Hinton's recommendation?

A. No. Mr. Hinton's recommended CT installed cost of $650 per kW does not reflect the Company's installed cost per kW.

Q. Regarding the testimony of Mr. Don Reading on behalf of the Renewable Energy Group, do you have any comments about his recommendation for the CT capital cost?

A. On page 31 of this testimony, Mr. Reading recommended that the Commission direct the Company to recalculate its avoided cost rates using a CT capital cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This figure is the installed capacity cost estimate for the installation of a CT at a greenfield site that the Company prepared in response to a Public Staff data request.

Q. Do you agree with Mr. Reading's recommendation?

A. No. For the reasons I discussed earlier with respect to Mr. Hinton's testimony, the appropriate installed CT capital cost for use in this proceeding is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2013 dollars, which is the installed cost of a CT on a brownfield site.

Q. On page 30 of his testimony, Mr. Reading stated that the Company's installed CT cost did not include AFUDC and financing costs. Is Mr. Reading correct?

A. Mr. Reading is correct that AFUDC and financing costs are not included in the installed CT figure, but such costs are accounted for in the Company's calculation of avoided capacity costs. Like other components of the avoided capacity costs such as the PAF, AFUDC and financing costs are accounted for separately by the Company's calculations and are indeed included in the final avoided capacity cost rates. Because financing and AFUDC costs are accounted for elsewhere in the Company's model, including them in the installed CT figure would result in double counting of those costs.

Q. **Did Mr. Reading's testimony address the issue of the appropriate Performance Adjustment Factor ("PAF") for solar QFs?**

A. Yes. On pages 32 through 36 of his testimony, Mr. Reading essentially restates the comments and arguments made by REG in its initial comments filed in this proceeding, with one additional discussion discussed below. *See* Renewable Energy Group Initial Comments (February 7, 2013) ("*REG Initial Comments*"). My direct testimony in this proceeding set out the Company's position of the appropriate PAF for solar QFs and responded to the comments and arguments of REG in the REG Initial Comments. *See* Direct Testimony at pages 9 – 21. Because the REG Initial Comments and Mr. Reading's testimony on the PAF issue are essentially identical, to avoid unnecessary duplication, I adopt pages 9 through 21 of my direct testimony in rebuttal to the testimony of Mr. Reading on the PAF issue.

Q. **You mentioned that there was one additional discussion. Please explain.**

A. On page 35 of the his testimony, Mr. Reading noted that (1) SB 3 has been in effect for five years, (2) 2012 was the first year that utilities were subject to an increase in the REPS requirement, and (3) SB 3 was not modified in the 2013-2014 legislative session.

Q. Do these developments affect the Company's position on the appropriate PAF for solar and wind QFs?

A. No. These developments do not justify raising the PAF to 2.0 for solar and wind QFs.

Q. Regarding the testimony of Public Staff Witness Mr. Kennie Ellis, do you have any comments about his recommendation that DNCP offer Option B type avoided cost rates?

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

Q. Have you reviewed the testimony of Mr. Karl Rábago on behalf of the NC Sustainable Energy Association?

A. Yes.

Q. What does Mr. Rábago recommend with respect to rates at issue in this proceeding?

A. Mr. Rábago recommends that the Commission adopt a PAF for solar QFs of 2.0. *See* Rábago Testimony at 25-26.

Q. Do you agree with Mr. Rábago's recommendation?

A. No, as discussed on pages 9 through 21 of my direct testimony, the Company does not believe that a PAF of 2.0 for solar or wind QFs is appropriate.

Q. Does Mr. Rábago make any other recommendations in his testimony?

A. Mr. Rábago appears to recommend that the Commission abandon the peaker methodology of determining avoided costs, at least at it relates to solar QFs.

Q. What does Mr. Rábago recommend that the Commission use in lieu of the peaker methodology?

A. A "value of solar" ("VOS") analysis.

Q. What is a VOS analysis?

A. Generally, as described by Mr. Rábago, a VOS is an evaluation of the costs and benefits of distributed solar generation. Mr. Rábago believes that the results of a VOS are a better indicator of the "full avoided costs" of distributed solar generation.

Q. Did you believe that the VOS approach is an appropriate way for the Commission to determine avoided costs.

A. No. As I testified earlier, avoided costs are defined under PURPA as "the incremental *costs* to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2013) (emphasis added).

The VOS as described by Mr. Rábago provides compensation to QFs not only for the costs that are avoided by utilities but also for perceived benefits of solar QFs. These benefits include items such as "reputational community participation," recognition of financial risks associated with "future control regimes" and "societal benefits" such as job growth, and increased local tax revenues. This Commission has consistently held that "uncertain and unquantifiable costs such as those associated with environmental externalities should not be taken into account in calculating avoided cost rates . . . ." *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2006,* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 22-23, Docket No. E-100, Sub 106 (Dec. 19, 2007) ("2006 Biennial Order").

While some of the items mentioned by Mr. Rábago may have value to an individual or a locality (e.g., job growth associated with a solar facility or increased local tax revenues) or value to society generally, they are simply not costs that are avoided by a utility through the purchase of energy and capacity from a solar QF. The Company, for instance, does not avoid any "reputational community participation costs" as a result of the purchase of energy and capacity from a QF.

In sum, the types of value adders discussed by Mr. Rábago are not properly included in the calculation of avoided cost pursuant to PURPA. Other avenues exist for local, state and federal entities, if they choose, to compensate QFs for these types of intangible or unquantifiable benefits, as currently evidenced by the various tax benefits, renewable energy credits and other incentives for QFs that produce these sorts of benefits.

Q. Has the Commission provided any guidance on the appropriateness of including compensation for compliance with future environmental control cost?

A. Yes, in Docket E-100, Sub-74, the Commission held that:

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

1994 Biennial Order at 24.

Similarly, in Docket No. E-100, Sub 106, the Commission rejected the arguments that avoided cost rates should include an allowance for general "environmental impacts that may be caused by generating plants." 2006 Biennial Order at 23. The Commission held that under PURPA, rates paid to a QF must equal the monetary costs a utility avoids by obtaining power from a QF. *See id.* at 23-24 ("Environmental externality costs . . . cannot be properly included in avoided costs.").

Q. Do DNCP's avoided cost rates represent the full avoided cost of QF power?

A. Yes. The peaker methodology utilized by the Company does identify and include the quantifiable costs that the utility can actually avoid by the purchase of energy and capacity from a QF. The Company's avoided cost calculations include recognition of energy, capacity, line losses, and known and quantifiable emissions such as sulfur dioxide and nitrogen oxide.

Q. Did Mr. Rábago perform a VOS for this proceeding or draw upon any North Carolina-specific VOS in this testimony on which the Commission could rely?

A. No. Mr. Rábago testified that none of the VOS studies he analyzed for this testimony included specific data from a North Carolina electric utility's service territory. In addition he testified that he was not aware of any published VOS study results in North Carolina.

Q. Did Mr. Rábago include any VOS studies in his testimony?

A. Yes. Exhibit-KRR-3 to his testimony is a VOS performed for New Jersey and Pennsylvania, which indicated that the VOS for that area could be $200 to $300/MWh. Rábago Testimony at p. 13. In addition, Mr. Rábago included as Exhibit-KRR-2 to his testimony a Rocky Mountain Institute ("RMI") report entitled "A Review of Solar PV Benefit and Cost Studies" that summarized 15 VOS and other studies addressing distributed solar generation benefits and costs (the "RMI Report").

Q. Did you review the studies and summaries included in Mr. Rábago's testimony?

A. Not in great detail because they did not relate to North Carolina or this proceeding and as I discussed above, I believe that the VOS approach in general is inconsistent with PURPA. I do note however, that the executive summary of the RMI Report stated the following:

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

RMI Report at page 5.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS OF BRUCE E. PETRIE

I graduated from Clarkson University in 1983 with a Bachelor of Science degree in Mechanical Engineering. From 1983 to 1986 I worked for Babcock and Wilcox designing tools for nuclear power plant maintenance. In 1988 I earned a Master of Business Administration degree from Virginia Tech.

I worked for Niagara Mohawk Power Corporation from 1988 through 1998 in generation planning, fuel procurement, and wholesale power marketing, and then at Old Dominion Electric Cooperative from 1998 until 2001 as a power supply analyst. I joined the Company in April 2001 as an electric pricing and structuring analyst. My responsibilities included the pricing and structuring of wholesale electric transactions, project financial analysis, and analytical support to the Energy Supply group.

In October 2007, I was promoted to Manager of Generation System Planning. I am currently responsible for the Company's mid-term operational forecast (PROMOD model) and forecasting of the Company's long term avoided costs.

BY MS. KELLS:

Q Mr. Petrie, do you have with you a summary of your rebuttal?

A (Mr. Petrie) Yes, I do.

Q Would you please give it now?

A (Mr. Petrie) In my rebuttal, I respond to the direct testimony of the Public Staff witnesses and the testimony filed by witnesses for the Renewable Energy Group, or REG, and the North Carolina Sustainable Energy Association, or NCSEA.

Regarding Public Staff's suggestion that Dominion offer avoided cost rates similar to the Option B rates offered by Duke, as I discuss in my rebuttal, Dominion is not opposed to adding an Option B-type rate to its existing rate offerings, provided that the PAF used in the Option B-type rate offering is 1.2 for non-hydro QFs.

My rebuttal testimony also again explains the reason that Dominion does not support a PAF of 2.0 for QFs other than run-of-river facilities, including for solar and wind QFs.

Finally, as I explain in my rebuttal testimony, Dominion does not believe that a VOS is an appropriate way to determine avoided cost for solar facilities. A

VOS would compensate solar QFs for their perceived benefits, in addition to the utilities' avoided costs. These are not costs that are avoided by a utility by purchasing energy and capacity from a QF, and so are not avoided costs, and should not be reflected in a calculation of utilities' avoided costs. With regard to environmental externality costs specifically, this Commission has consistently held that these types of costs should not be accounted for in calculating avoided cost rates.

This concludes my summary of my rebuttal.

MS. KELLS: The witnesses are available for cross examination.

COMMISSIONER BROWN-BLAND: All right. We'll start with you, Mr. Youth.

CROSS EXAMINATION BY MR. YOUTH:

Q Mr. Petrie, I've got a few questions for you. Were you present when Mr. Dodge asked the Public Staff witnesses a question about the PAF serving as sort of an equitable tool to offer QFs relief?

A (Mr. Petrie) Yes.

Q And you understand that Mr. Rabago made a recommendation that the PAF for solar be increased to 2.0 and then in this proceeding for this biennium, and then

after that he said this Commission and the parties should look at some way to figure out how to get a more precise evaluation of what solar should be paid in avoided cost rates. Is that a fair summary? I'm not trying to trick you.

A (Mr. Petrie) I mean, what I heard him say was that he endorsed this value of solar study, and he says that the peaker method is deficient. That's what I heard him say.

Q Did he say the PAF tool was a broken tool?

A (Mr. Petrie) That's not my recollection of what he said.

Q Maybe if I speak in terms of a hypothetical. If Mr. Rabago were saying the VOS study for North Carolina, as well as the other studies that were attached to his testimony, should serve as evidence in support of invoking the equitable relief of elevating a PAF for solar from 1.2 to 2.0, and then dealing with a more precise solar avoided cost rate in the future, would you agree that he would not be asking for an avoided cost rate to be set based on the VOS, the value of solar study?

A (Mr. Petrie) I'm sorry. I --

MS. KELLS: Can you break that question down a little bit? That would really help.

A (Mr. Petrie) I didn't follow that.

BY MR. YOUTH:

Q I apologize. We're all wearing down. Mr. Rabago offered the VOS and his analysis in support of moving the PAF from 1.2 to 2.0 for solar in the near term, correct?

A (Mr. Petrie) That's right.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: Ms. Mitchell?

MS. MITCHELL: I have several questions for Mr. Trexler.

CROSS EXAMINATION BY MS. MITCHELL:

Q Mr. Trexler, I'll try to scoot over a little bit so I can be in your line of sight. On pages 2 through 11 of your rebuttal testimony, you describe Article 6 of the agreement of the sale of the electrical output to Virginia Electric & Power Company; is that correct?

A (Mr. Trexler) Yes.

Q And this agreement for the sale of electrical output to Virginia Electric & Power Company is also referred to as the Power Purchase Agreement, or the PPA; is that correct?

A (Mr. Trexler) Yes.
Q So if I refer to PPA during my cross examination, that's what I'm referring to. And Article 6 is commonly referred to as the regulatory disallowance clause; is that correct?
A (Mr. Trexler) That's what it's been referred to in this case.
Q Okay. Sometimes known as the reg-out, I believe, as your counsel has referred to it?
A (Mr. Trexler) It has been called that, but I think that more appropriate is the regulatory disallowance.
Q Okay. Fair enough. And in my cross examination, I'll refer to Article 6 as regulatory disallowance.
A (Mr. Trexler) Okay.
Q Do you have a copy of your rebuttal testimony in front of you?
A (Mr. Trexler) I do.
Q On page 2, lines 7 through 13, you testify that Article 6, or the regulatory disallowance clause, addresses the situation in which a regulatory body with jurisdiction, such as the North Carolina Utilities Commission or the Virginia equivalent, issues an order

that prohibits the recovery of payments made to a QF and/or requires the Company to refund to its ratepayers already made to a QF. Is this an accurate representation of your testimony?

A (Mr. Trexler) I would say yes.

Q Okay. On page 2, lines 13 through 18, you go on to explain that in the event of a disallowance order, the regulatory disallowance clause provides that the rates available under the applicable rate schedule would be reset on a prospective basis at the levels that the jurisdiction and regulatory body determines the Company is allowed to recover through rates; is that correct?

A (Mr. Trexler) That is correct.

Q And then you also state, and I'm going to read directly from your testimony on lines 16 through 18, just so I'm accurate, the following, "If a disallowance order requires the Company to refund to its ratepayers previous payments to a QF, then the QF is similarly required to refund the Company those amounts." Is that correct?

A (Mr. Trexler) That's what it says.

Q Okay. At this point in time I'm going to hand out a copy of the contract provision, and I'm going to walk through it with you and ask you several questions specific to the language of the provision.

MS. MITCHELL: So if it's okay, I'm going to pass it out.

COMMISSIONER BROWN-BLAND: Do you want to mark this exhibit as REG --

MS. MITCHELL: Trexler Cross 1.

COMMISSIONER BROWN-BLAND: All right. It will be so identified; rebuttal.

MS. MITCHELL: Trexler Rebuttal, yes.

(Whereupon, REG Trexler Cross Rebuttal Exhibit Number 1 was marked for identification.)

BY MS. MITCHELL:

Q Okay. Mr. Trexler, in front of you appears the excerpt from the Dominion PPA. It's Article 6. And would you accept, subject to check, that it's applicable Schedule 19-FP?

A (Mr. Trexler) Subject to check.

Q Okay. I'm just going to ask you several questions, walk through the contract provision so that we're all clear on what it requires of the Company and of the QF. So I'm just going to read through phrase by phrase and ask you to confirm that I'm reading it correctly, okay?

A (Mr. Trexler) Okay.

Q So Article 6 begins as follows, "Should the North Carolina Utilities Commission (NCUC), Virginia State Corporation Commission (SCC) or other regulatory or other legal body having jurisdiction (such as the Federal Energy Regulatory Commission) 1) not allow any future payments to non-utility generators..." and in this case a QF would be a non-utility generator; is that correct?

A (Mr. Trexler) That's correct.

Q Okay. "...(generally or to Operator specifically) for energy or capacity (including Contracted Capacity) or both to be included in Dominion North Carolina Power/Dominion Virginia Power's rates charged to customers, 2) at any time prohibit Dominion North Carolina Power/Dominion Virginia Power recovering from its customers sums related to payments previously made to non-utility generators (generally or to Operator specifically), or 3) order Dominion North Carolina Power/Dominion Virginia Power to pay back to its customers sums related to amounts collected as a result of payments to non-utility generators (generally or to Operator specifically) (hereinafter the sums referred to in both 2) and 3) above shall be referred to individually and collectively as the 'Disallowed Payments'), Operator shall be required both to accept from the effective date of the Order from the NCUC, SCC, or other regulatory or legal body having jurisdiction ('Commission Order') payments at the level of rates that will be allowed to be recovered in rates charged to Dominion North Carolina Power/Dominion Virginia Power's customers and to refund to Dominion North Carolina Power, A) the identified dollar amount of the Disallowed Payments specifically identified in the Commission Order as resulting from payments made to Operator hereunder, or B) if the Disallowed Payments are not specifically identified, Operator's pro-rata share of the Disallowed Payments which shall be equal to the product of (1) the total amount of payments made under this Agreement for the period of time such Disallowed Payments have been calculated, and (2) a fraction whereby the numerator is the Disallowed Payments and the denominator is the total amount of payments made to all Non-utility Generators, that were considered in the Commission Order, for the same period of time that such Disallowed Payments have been calculated." Did I read that correctly?

A (Mr. Trexler) I believe so.

Q That may be the longest sentence I've ever read in -- okay. Just going back through the contract provision, as I understand the contract provision to

work, if a relevant regulatory jurisdiction such as the North Carolina Utilities Commission or the Virginia equivalent issues an order that disallows the recovery of payments made to the QF, this contract provision would allow the Company to 1) reset the rate in the contract at a rate that's allowed by the Commission for recovery, by the regulatory body for recovery; is that correct?

A (Mr. Trexler) Essentially what you're saying, yes. If a regulatory agency that hasn't spoke here issues an order that essentially resets what they're -- they're issuing an order that says you were paying something in excess of your avoided cost, and they reset to what you're avoided cost should have been, in their view, then payments are rebased under the contract to what that commission or regulatory body has established as the avoided cost.

Q Okay. So it allows the Company to reset the rate, as you've just indicated, at a level that the Commission says is -- reflects your avoided cost and is, therefore, recoverable.

A (Mr. Trexler) I believe -- I would say it provides a mechanism in the contract that contractually resets the rates in accordance with the order.

Q Okay. The contract provision also allows the

Company to recover money from the QF; is that correct?

A (Mr. Trexler) In the event the Commission has said that there was an amount that was from before that they want refunded to the ratepayer, yes, it could.

Q Okay. I want to go back to -- let's see -- subparagraph 2) which occurs on line one, two, three, four, five six of Article 6. So starting at the 2), it says, "at any time prohibit Dominion North Carolina Power/Dominion Virginia Power from recovering from its customers sums related to payments previously made to non-utility generators (generally or to Operator specifically), or 3) order Dominion North Carolina Power/Dominion Virginia Power to pay back to its customers sums related to amounts collected as a result of payments to non-utility generators," and then in the next line it says, "(hereinafter the sums referred to in both 2) and 3) above shall be referred to individually and collectively as the 'Disallowed Payments')," so the contract provision gives the Company the right to recover disallowed payments; is that correct?

A (Mr. Trexler) In the event of an order.

Q Right.

MS. KELLS: I'm sorry, can you -- I missed -- can you say that question again?

BY MS. MITCHELL:

Q The contract provision gives the Company the right to recover from the QF the disallowed payments.

MS. KELLS: Mr. Trexler, can you answer again?

A (Mr. Trexler) Well, the lines that you specified that you've read here define those. It's further down where it -- the provisions speaks to those amounts being refunded. But again, I go back, it's all in the event of an order.

BY MS. MITCHELL:

Q Understood. So your testimony is in the event of an order, the Company is allowed -- in the event of a disallowance order, to be clear, the Company is allowed to recover sums identified by subparagraph 2 and subparagraph 3 of the contract?

A (Mr. Trexler) If the order specifies -- if the order specifies such going backwards. In other words, an order could be just prospectively. The order doesn't necessarily say that if they order something prospectively, and they don't say you can't -- you know, you need to go back or you need to refund the ratepayers, then this doesn't give us the right to go for what we've already paid. We have to follow -- what I believe this says is that we have to follow the order, and it gives us the right to follow the order.

Q Okay. I mean, I understand that. I'm just -- you just said if the order requires us to go back or to refund. Can you explain what you meant by that?

A (Mr. Trexler) I think this speaks for that.

Q Okay. Let's return to your testimony.

A (Mr. Trexler) Okay.

Q On page 3, lines 5 through 8, you indicate that the contract provision equitably allocates the burdens of the disallowance order; is that correct?

A (Mr. Trexler) That's what I -- yes, that's what's said there.

Q But doesn't the contract provision allow the Company to collect from the QF any and all amounts in the disallowance order that's attributed to the QF?

A (Mr. Trexler) Well, if you look at -- by law we're obligated to enter into contracts. Also, the law provides for us to get reimbursed for that through our rates. And our North Carolina law, I believe, states that we make nothing on it so it's a direct pass-through. So what I mean by equitably is if you look at who's got the money, in this case, Dominion is getting no money out of this contract. It's taking what it's obligated to pay the QF and passes it on to its ratepayers. So what I mean by equitably is if there's a disallowance, if the Commission says we've got to no longer pay a certain amount and we've got to reduce the payment to the ratepayer or the obligation of the ratepayer, then if you don't pass that back to the QF, who is the one who is getting all of the funds from the payments from the ratepayers, then you're putting a burden on Dominion and its shareholders which I would believe to be inequitable.

Q I'm not sure that you answered my question. I said doesn't the contract -- my question was doesn't the contract provision allow the Company to collect from the QF any and all amounts in the disallowance order that's attributed to that QF?

A (Mr. Trexler) Yes.

Q Okay. Thank you. So what burden of a disallowance order does the Company bear?

A (Mr. Trexler) As --

Q Your testimony is allocates the burdens of a disallowance order equitably. I'm just trying to figure out what burdens of the disallowance order the Company bears.

A (Mr. Trexler) The Company would bear -- I was going to say if there's a difference in the difference between when rates are filed and when rates are collected and stuff, there's always -- there's always a gray line there. It's not, you know -- I don't think it's black and white, but in simple terms, the entire burden is shifted back to the QF, again, where the money is at.

Q So just so I'm clear, did you just testify that the burden of the disallowance order is shifted back to the QF?

COMMISSIONER BROWN-BLAND: I believe that's what he said.

MS. MITCHELL: Okay. I'm going to move on.

BY MS. MITCHELL:

Q On page 11, lines 7 through 9 of your rebuttal testimony, --

A (Mr. Trexler) Can you repeat that, please?

Q Sure. Page 11, lines 7 through 9, you testify that the Company has entered into five Schedule 19 contracts with QFs?

A (Mr. Trexler) That's correct.

Q And then you go on to testify, "of which three have entered into commercial operation and two have started construction."

A (Mr. Trexler) That's correct.

Q Can you tell me what types of generation these QFs are?

A (Mr. Trexler) Three are solar and two are biomass, subject to check, but I believe that's correct.

Q You're not aware of these specific projects?

A (Mr. Trexler) I am. I am, so I'm --

Q Could we -- could I ask --

A I will say, yes, it is two biomass and three solar.

MS. KELLS: We can confirm that.

MS. MITCHELL: Okay. Could you provide that information in a late-filed exhibit?

BY MS. MITCHELL:

Q And what size are these QFs?

A (Mr. Trexler) I would say from roughly -- can we state rough numbers? Roughly, 100 kW to 5 MW.

Q That's quite a range. I'm just --

A (Mr. Trexler) All right.

Q Do you --

A (Mr. Trexler) The two biomass plants are in the neighborhood somewhere between 100 and 300 MW. We've got two solar projects that are in the neighborhood of between 1 and 2 MW and one 5-MW solar. I don't know the numbers right off the top of my head, if you need more specifics than that.

MS. MITCHELL: I would like more specifics than that. I would like to know the size of these QFs, in addition to the specific generation types.

BY MS. MITCHELL:

Q **And do you have any information about who owns these QFs?**

A (Mr. Trexler) I can tell you the names of them.

Q **The names of the owners?**

A (Mr. Trexler) No. The names of the QFs. I don't -- you know, I don't know that there is anybody in the utility industry that can tell you the ultimate owners of any QF. They're all LLCs, so you know, --

MS. KELLS: I'm not sure that that information is public.

COMMISSIONER BROWN-BLAND: And, plus, I believe he's answered to the extent of his knowledge.

MS. MITCHELL: Okay. He just testified that he's aware of 5 QFs, and so I'm just trying to understand how much he knows about these projects. I'll move on.

BY MS. MITCHELL:

Q **Do you have any information about whether these projects were financed?**

A (Mr. Trexler) Well, I guess in simple terms they were financed somehow. I don't know exactly what you mean by "financed." If you could expand on that, I could -- what do you mean by "financed"?

Q Well, were they owner financed? Did the owner pay for these projects?

A (Mr. Trexler) I do not know.

Q In your summary, you indicate that -- I'm looking at page 4 of your testimony summary. It's the last paragraph. It's three lines up. You say "...Article 6 with developers who have obtained financing for their projects." Can you explain that statement?

A (Mr. Trexler) Well, in simple terms, in order to develop a project, you have to come up with the finances somehow. So I do know for a fact that the solar projects all have -- well, I can't say all of them. I know for a fact two of them have financing that are not just Joe Homeowner putting up the money.

Q And so what type of financing would it be?

MS. KELLS: I'm going to object. I don't think Mr. Trexler is privy to the details of the QF lenders' financing arrangements in his position, or that that topic regularly enters conversations that he has with project developers.

COMMISSIONER BROWN-BLAND: Mr. Trexler, you may answer whether you know or you don't know, and if you have a basis, what the basis is for your knowledge.

A (Mr. Trexler) One of the solar projects that I have, I actually was in a conversation with their lender. And to the extent what the lender means, it is my understanding it was a commercial lender, so I had a discussion with a commercial lender on that. The second project, the developer represented himself as one of numerous -- that it was a lender through -- that it was a commercial -- that it was a group of commercial lenders, you know, that were the ultimate money behind the other project. Beyond that, I don't know how those projects were financed.

BY MS. MITCHELL:

Q Okay. And you know for a fact that the two projects you've mentioned that involve your having conversations with lenders or your hearing about lenders, those lenders financed the deals?

A (Mr. Trexler) No, I don't know who financed it.

Q Okay. Okay. I'll move on.

A (Mr. Trexler) I'm just telling you that I know that two of them, financing was discussed.

Q Okay. Thank you. Page 11, lines 11 through 13 of your rebuttal testimony, you indicate that the Company has entered into a PPA with a 20-MW QF that contains a provision similar to the regulatory disallowance clause?

A (Mr. Trexler) That's correct.

Q Can you explain what you mean by "similar"?

A (Mr. Trexler) I can't say that word for word, it's exact, but in all, I'm not a lawyer, but I would say it says the same thing. It's very close. It was built -- it was based off of the North Carolina Schedule 19, Article 6.

Q Does it allocate the burdens of a disallowance order the same way that Article 6 does?

A (Mr. Trexler) Yes, it does.

Q Has that project been -- are you aware of the status of that project that's the subject of the PPA?

A (Mr. Trexler) It's my understanding, the last I was informed of them -- and, you know, it's down here in North Carolina. I don't personally know whether iron is in the ground at this point, but they were in the final stages of development, getting ready to start construction.

Q Are you aware of whether that project has obtained financing?

A (Mr. Trexler) They had indicated that they had their financing lined up.

Q But you do not know for sure?

A (Mr. Trexler) I do not.

Q Okay. Are you aware that the Public Staff has previously expressed concerns about this contract provision?

A (Mr. Trexler) Yes.

Q Are you aware that Public Staff has previously taken the position that this provision is likely to discourage QF development?

A (Mr. Trexler) I have read that.

Q On page 3, lines 1 through 2 of your rebuttal testimony, you testify that the Company would contest any such disallowance. Presumably that means any disallowance in a disallowance order; is that correct?

A (Mr. Trexler) That's correct.

Q Does the contract obligate the Company to contest a disallowance order?

A (Mr. Trexler) No, it doesn't, but I believe, you know, if that would help to add those words, that would be something we could do. You know, again, I would say we need to put some sort of reasonableness clause in there.

Q Just one last question. I'm just going to point to it in your testimony summary. On page 3, I think that's the second paragraph, you indicate that Dominion has twice been disallowed recovery of such

costs; is that correct?

A (Mr. Trexler) That is correct.

Q Are you aware of whether those instances involved QFs -- PPAs with QFs that were selling power pursuant to rates -- standard rates approved by this Commission? And by standard rates, I mean those available to QFs 5 MW and smaller, those available to small power producers.

A (Mr. Trexler) The one that this Commission disallowed was a result of an arbitration in Virginia, and so it was not the standard rate. The one that the Virginia SEC, the disallowance resulting from that did involve the entire class, that anybody that used those rates which involved rates similar to these, you know, the tariff. Now, ultimately, the Commission, if my memory serves me right on that case, the Commission decided not to impose the disallowance on the ones that were under contract in the tariff. The tariff, I believe, changed going forward immediately, but anybody who already was on it was not included in the disallowance. It was only those that did not qualify for the tariff, but was getting the same rates outside of the tariff.

MS. MITCHELL: Okay. I have just one last question, just to make sure I'm clear on his response.

BY MS. MITCHELL:

Q So the two instances in which disallowance orders were issued, neither one of them involved standard rates approved by this North Carolina Utilities Commission?

A (Mr. Trexler) Would you repeat that again?

Q Neither of the two instances in which a disallowance order was issued, that you've testified to, involved standard rates approved by this North Carolina Utilities Commission?

A (Mr. Trexler) In those -- those past two did not, --

Q Okay.

A (Mr. Trexler) -- but that doesn't mean one in the future couldn't, you know, if somebody else, if another regulatory body believed that the rates set by this Commission exceeded our avoided cost.

MS. MITCHELL: Okay. Thank you. No further questions.

MS. OTTENWELLER: No questions.

COMMISSIONER BROWN-BLAND: No cross. Any redirect?

MS. KELLS: Yes, please.

COMMISSIONER BROWN-BLAND: Go ahead.

REDIRECT EXAMINATION BY MS. KELLS:

Q Mr. Trexler -- just give me one moment -- does Article 6, the provision that we've been discussing, give the Company the right to adjust the rates paid to QFs for any reason other than a regulatory disallowance order?

A (Mr. Trexler) It does not. It only speaks to how things would be handled in the event an order is issued.

Q And you testified that Article 6 is part of the contracts of those six QFs that are referenced in your testimony on page 11, I believe it was. I'll state that again. You mentioned that the Company entered into five Schedule 19 contracts with QFs in the past couple years, and one PPA with a larger 20-MW QF, right?

A (Mr. Trexler) That is correct.

Q And those agreements, did any of those agreements contain an Article 6 provision?

A (Mr. Trexler) They all contain a provision that is essentially Article 6.

Q So they all contain a provision that is either Article 6 or has the same effect?

A (Mr. Trexler) That is correct.

Q Regardless of whether the QF affected by a regulatory disallowance order is one that has rates under a standard contract such as FP or is a larger QF that falls outside the tariff, would the impact to the Company of a regulatory disallowance order be any different?

A (Mr. Trexler) No.

Q What is the impact to the Company of a regulatory disallowance order in either case?

A (Mr. Trexler) Without the disallowance clause, the Company would have to bear the difference between continuing to pay the QF the full amount and the amount that is allowed to be passed through to the ratepayers.

Q And so since the Commission in such a case would have decided that the rates being paid to the QF exceeded the Company's avoided cost and so disallowed that amount, but the Company would continue paying the same rates to the QF, that would essentially mean the Company would be paying rates to the QF in excess of its avoided cost, correct?

A (Mr. Trexler) That is correct.

Q And in both cases, whether the QF -- regardless of the size of the QF, the impact to the Company in terms of bearing the -- without Article 6, that the Company would bear the burden and the shareholders would bear the burden of the disallowance order would be the same, correct?

A (Mr. Trexler) That's correct.

MS. KELLS: I don't have anything else.

COMMISSIONER BROWN-BLAND: All right. Questions by the Commission? Go ahead, Chairman Finley.

EXAMINATION BY CHAIRMAN FINLEY:

Q Mr. Trexler, I'm looking at page 6 of your rebuttal testimony, a case you cite there on line 14.

A (Mr. Trexler) I'm sorry. You're saying page 14?

Q Page 6, line 14.

A (Mr. Trexler) Oh, I'm sorry.

Q You with me?

A (Mr. Trexler) Yes.

Q That's the case that you mentioned a moment ago where there was an arbitration in Virginia?

A (Mr. Trexler) That is correct.

Q But it was an arbitration under the auspices of Virginia State Corporation Commission.

A (Mr. Trexler) That is correct.

Q And the Virginia State Corporation Commission, pursuant to the arbitration, set the avoided cost rates for those electric producers which were Ultra Cogen facilities, as I recall.

A (Mr. Trexler) Yes.

Q Okay. And they were long contracts of some length, right?

A (Mr. Trexler) They were, yes.

Q And then some years later, Virginia North Carolina Power came to this Commission and asked for general rate relief, and in the course of that case, this Commission disallowed part of the avoided cost that the Virginia Commission had established, right?

A (Mr. Trexler) That is correct. Just, yes, a part of it.

Q And your position is since this Commission disallowed costs that the Virginia Commission had established, it would be unfair for you, your stockholder to have to bear that burden when you're turning around and continuing to pay the generator the rates that the Virginia Commission established.

A (Mr. Trexler) That is correct.

Q And when you say equitably, you mean it's inequitable for your stockholder to have to bear the cost that you're turning around to pay to the co-generator.

A (Mr. Trexler) Yes.

Q And you took that one all the way to the U.S. Supreme Court.

A (Mr. Trexler) That is correct.

Q **So you certainly contested that disallowance.**

A (Mr. Trexler) Yes, we did.

Q **Of course, your stockholder was paying the cost as opposed to passing it to the co-generator.**

A (Mr. Trexler) Right.

Q **And that's the gist -- those types of situations are the gist of what you're trying to address in Article 6.**

A (Mr. Trexler) That is correct.

Q **And as far as you know, the purpose of PURPA is for you to pay avoided cost, but for you to turn around and collect all those avoided costs that pay to the generating facility from the ratepayers.**

A (Mr. Trexler) That is correct.

CHAIRMAN FINLEY: All right. Thanks.

COMMISSIONER BROWN-BLAND: Other questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: Questions on the Commission's questions?

(No response.)

COMMISSIONER BROWN-BLAND: Well, it looks like we've come to the end here. Do we have any motions pertaining to these witnesses?

MS. KELLS: Yes. I'd like to move that Mr. Trexler's exhibit RJT-1 be admitted into the record.

COMMISSIONER BROWN-BLAND: It will be admitted and received into evidence.

(Whereupon, Exhibit RJT-1 was admitted into evidence.)

MS. MITCHELL: Commissioner Brown-Bland, I'd like for REG Trexler Rebuttal Cross 1, I'd ask that it's moved into evidence.

COMMISSIONER BROWN-BLAND: All right. That motion is allowed, and it will be received into evidence.

(Whereupon, REG Trexler Rebuttal Cross Examination Exhibit 1 was admitted into evidence.)

COMMISSIONER BROWN-BLAND: All right. So some housekeeping matters. Just out of an abundance of caution, to be certain that I did admit -- I know earlier I had a conversation with Mr. Youth, so out of an abundance of caution, I'd just say all the testimony and all the exhibits that were attached to the testimony have been offered and received into evidence.

(Whereupon, Exhibits KRR-1 through KRR-7 were admitted into evidence.)

(Whereupon, NCSEA Bowman Rebuttal Cross Exhibit 1 was admitted into evidence.)

COMMISSIONER BROWN-BLAND: And the comments that were earlier admitted, I understand there's been conversations in between, and everyone has agreed to make sure that the court reporter has a copy of what you want to be treated as evidence in this matter.

MS. FENTRESS: Well, Madam Chair, I would ask not treated as evidence, but perhaps added as an appendix to the record or to the transcript, was my understanding, that comments would not be treated as evidence, but --

COMMISSIONER BROWN-BLAND: They have been received as evidence already, but she's going to append them is how she's going to handle it.

MS. FENTRESS: The comments? Is that --

COMMISSIONER BROWN-BLAND: The comments themselves that are not sworn to will be treated as such. Those that are sworn to will be treated as affidavits.

MS. FENTRESS: Okay.

COMMISSIONER BROWN-BLAND: I mean, they are affidavits and they will be treated as if given from the stand.

MS. FENTRESS: Thank you.

COMMISSIONER BROWN-BLAND: All right. Proposed orders and briefs, any issue with the usual 30 days from the mailing of the transcript?

MS. FENTRESS: None from us.

COMMISSIONER BROWN-BLAND: All right. Then it will be so ordered that proposed orders and/or briefs be filed within 30 days from the mailing of the transcript.

And at this point I want to thank you all for your high level of preparation and your assistance of the Commission with the understanding of the issues and your respective positions. And I would also ask that with respect to the contract disputes that remain and have not been resolved, I would encourage you to keep talking. If there's a way that the contract language could be modified, as has been suggested by one of the witnesses here, that may permit the parties to have a higher level of mutual satisfaction and acceptance, that you at least pursue that and notify the Commission should you resolve that.

And let me say thank you for your patience and your professionalism, and we shall stand adjourned.

(The hearing was adjourned.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Court Reporter and Notary Public, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 136 was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of the said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 14th day of November , 2013.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150