PLACE: Dobbs Building, Raleigh, North Carolina

DATE: October 29, 2013

DOCKET NO.: E-100, Sub 136

TIME IN SESSION: 1:03 P.M. TO 5:00 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 1

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COMMISSIONER BROWN-BLAND: Good afternoon. Let's come to order and go on the record. I am Commissioner Tonola D. Brown-Bland, presiding Commissioner for this afternoon's hearing. And with me are Commission Chairman Edward S. Finley, Jr. and Commissioners Bryan E. Beatty, Susan Warren Rabon, Jerry C. Dockham, and James G. Patterson.

I now call for hearing Docket Number E-100, Sub 136, In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities 2012. These are the 2012 biennial proceedings held by this Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 and applicable Federal Energy Regulatory Commission regulations pertaining to this Commission's responsibilities for determining each electric utility's avoided costs with respect to rates for purchases of power from qualifying co-generators and small power production facilities.

These proceedings are also being held pursuant to G.S. 62-156, which requires this Commission to determine the rate to be paid by electric utilities for power purchased from small power producers as defined in

G.S. 62-3, Sub (27a).

On June 18, 2012, the Commission issued its Order Establishing Biennial Proceeding Requiring Data and Scheduling Public Hearing. Pursuant to said order, Duke Energy Carolinas LLC, hereafter D-E-C or DEC; Progress Energy Carolinas, now and hereafter referred to as Duke Energy Progress, Inc., D-E-P or DEP; Virginia Electric and Power Company doing business as Dominion North Carolina Power, DNCP or Dominion; Western Carolina University and New River Power and Light Company were made parties to these proceedings, hereinafter referred to collectively as the Utilities. Said order also set the public hearing for 9:00 a.m. in this hearing room on February 12, 2013 and established, among other things, the times for the filing of the parties initial statements, comments and exhibits, petitions for intervention, and comments and exhibits of non-utility parties wishing to file them.

The following parties have filed petitions to intervene that have been granted by the Commission in these proceedings: The North Carolina Sustainable Energy Association, NCSEA; The Public Works Commission of the City of Fayetteville, FPWC; Carolina Utility Customers Association, Inc., CUCA; The Carolina Industrial Groups for Fair Utility Rates I, II, and III, CIGFUR I, II, and III; Renewable Energy Group, REG; North Carolina Electric Membership Corporation, NCEMC; and Southern Alliance for Clean Energy, S-A-C-E or SACE. Participation of the public staff has been recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On June 25, 2012, DEP filed confidential avoided cost data and on November 1, 2012 filed a rate schedule, Application for Standard Contract Terms and Conditions for Purchase of Power from Qualifying Facilities and a Motion to Suspend Availability of Previously Approved Long-Term Rates.

Also on November 1, 2012, all the electric utility parties filed statements, comments, and/or exhibits. On December 21, 2012, after considering comments filed by the Public Staff and other intervenors, the Commission issued an order granting DEP's Motion to Suspend Availability of Rates subject to conditions and requiring that DEP offer their proposed long-term fixed avoided cost rates subject to true-up pending a final order establishing rates in this docket.

On February 7, 2013, the Public Staff, NCSEA, and REG filed comments. Subsequently, on or before February 12, 2013, all electric utility parties filed

Affidavits of Public -- of Publication of Notice of Hearing, and the public hearing was held in this hearing room on February 12, 2013, as scheduled. Seven witnesses gave testimony at the public hearing. In addition, several consumer statements of positions have been filed in this docket.

On March 28, 2013, reply comments were submitted by the Public Staff, DNCP, and joint reply comments were submitted by -- by DEC and DEP.

Also on March 28, 2013, NCSEA filed a Motion for Consideration of Need for an evidentiary hearing. The Public Staff made a similar request in its March 28th comments.

On May 14, 2013, the Commission issued an order directing DEC and DNCP to offer their proposed long-term fixed avoided cost rates subject to true up pending a final order establishing rates in this docket.

After receiving comments from DEC, DEP, and DNCP opposing an evidentiary hearing, the Commission issued an order on June 6, 2013, scheduling evidentiary hearing and establishing procedural schedule, scheduling the hearing on issues identified by NCSEA, REG, and the Public Staff for Tuesday September 10, 2013 in this hearing room.

On June 26, 2013, the Public Staff filed a Motion for Revised Procedural Schedule. On July 1, 2013, the Commission issued an Order Granting Motion and Rescheduling Evidentiary Hearing and Procedural Schedule -- the hearing, rescheduling the hearing for 9:30 a.m., Tuesday, October 29, 2013, in this hearing room.

As parties in this docket, DEC filed the testimony and exhibits of Theodore P. Pintcke, direct and rebuttal testimony of Glen A. Snider and Kendal C. Bowman. DNCP filed direct and rebuttal testimony of Robert J. Trexler and Bruce E. Petrie. NCSEA filed testimony and exhibits of Karl R. Rabago. REG filed direct testimony of Don C. Reading and John E. P. Morrison and an affidavit of Erik Stuebe. The Public Staff filed direct testimony of Kennie D. Ellis and John R. Hinton.

Having received from DEC and DEP oral notice of a settlement and a request to delay the hearing to allow time for the filing of a settlement agreement on October 28, 2013, the hearing was rescheduled by order of the Commission to begin at 1:00 p.m. Tuesday, October 29, 2013.

Also on October 29, 2013, the Public Staff filed a Stipulation of Settlement between DNCP and the

Public Staff; and also on October 29, 2013, DEC and DEP filed a Stipulation of Settlement between DEC, DEP, and the Public Staff.

Pursuant to G.S. 138A, 15(e) I remind members of the Commission of their duty to avoid conflicts of interest and inquire at this time as to whether any Commissioner has any known conflict of interest or appearance of such conflict with respect to this docket.

(No response.)

COMMISSIONER BROWN-BLAND: Let the record reflect that no such conflicts were identified. I now call upon counsel for the parties to announce their appearances for the record beginning with the Utilities.

MS. FENTRESS: Good afternoon. Kendrick Fentress appearing on behalf of Duke Energy Carolinas and Duke Energy Progress.

MR. ALLEN: Madam Chairman and Members of the Commission, my name is Dwight Allen. I'm also appearing on behalf of Duke Energy Carolina and Duke Energy Progress.

MR. SOMERS: Good afternoon, Members of the Commission. Bo Somers also on behalf of Duke Energy Carolinas and Duke Energy Progress.

MS. KELLS: Good afternoon, Chairman and

Members of the Commission. I'm Andrea Kells with McGuire Woods here today on behalf of Dominion North Carolina power. Also appearing with me today is Mr. Patrick Horne, also with McGuire Woods. He's been admitted to practice here pro hac vice. And also with us is Mr. Horace Payne, senior counsel with Dominion.

COMMISSIONER BROWN-BLAND: Thank you.

MS. RANKIN: I'm Gisele Rankin, an attorney with the Public Staff representing the Using and Consuming Public, and appearing with me will be Tim Dodge. I believe he's off trying to file the rest of the settlement.

COMMISSIONER BROWN-BLAND: All right.

MS. THOMPSON: Good afternoon, Madam Chair, Members of the Commission. Gudrun Thompson with the Southern Environmental Law Center representing Southern Alliance for Clean Energy. And with me has been admitted pro hac vice in this matter Katie Ottenweller of our Atlanta office. Katie is a member of the bar of the state of Georgia and Pennsylvania.

MS. MITCHELL: Good afternoon. I'm Charlotte Mitchell, Styers Kemerait & Mitchell here in Raleigh, appearing on behalf of the Renewable Energy Group.

MR. YOUTH: Good afternoon. I'm Michael Youth representing the North Carolina Sustainable Energy Association.

COMMISSIONER BROWN-BLAND: Welcome to everybody. We're, as always, glad to have you come be with us for a little while. Now, are there any preliminary matters that counsel would like to bring to the Commission's attention at this time? Ms. Fentress.

MS. FENTRESS: Thank you. We would like to address what you have already referenced, that DEC and DEP and the Public Staff have entered into a Settlement Agreement that resolves two pending issues, the two main pending issues between them in this proceeding. Late this morning we got word that REG and NCSEA were also going to join into the Settlement Agreement with respect to the CT cost.

And to that end, we have agreed that they would waive cross-examination of our witnesses and we of theirs on matters pertaining to the CT cost. REG Group, the REG Group and NCSEA, however, did not enter into the stipulation with respect to another prong of it, which is Option B, and they have reserved the right to litigate that issue with respect to the application of Performance Adjustment Factor.

The REG Group and DEC and DEP have also agreed that they will waive cross-examination of each other's witnesses with respect to the reduction in contract energy issue and let the Commission decide that issue on the pleadings and testimony that has been filed thus far. And we are prepared to amend the settlement agreement to make the -- to reflect what I've just reported as soon as this hearing is concluded or as soon as we can.

COMMISSIONER BROWN-BLAND: So let me understand. On the last issue, the agreement is for the Commission to decide on the --

MS. FENTRESS: Yes. Well, there are three issues essentially here. First is the amount of the installed CT cost. The Public Staff and the Utilities, the REG Group and NCSEA have agreed on what that should be.

The second issue is whether DEC or DEP would adopt an Option B or whether the Commission would impose a Performance Adjustment Factor of 2.0 on wind and solar QFs. The REG Group and NCSEA did not agree to the Option B prong of the Settlement Agreement but do want to continue to litigate the Performance Adjustment Factor.

And then there is a third issue that was really only between the REG Group and DEC and DEP, and that was the reduction in contract energy issue. We have agreed that we've said enough about it at this point and the Commission can make this decision on the pleadings and the testimony that's already in the record.

COMMISSIONER BROWN-BLAND: Thank you.

MS. FENTRESS: And then I would also like to ask because we have reached agreement on the CT cost with the parties with the exception of SACE, it was my understanding, and I'll check to see if this is still correct, that no one had any cross-examination questions for Ted Pintcke. And so if that is in fact the case, I would move now or at the appropriate time to stipulate his testimony into the record.

COMMISSIONER BROWN-BLAND: All right. Is there any objection to the receipt of Mr. Pintcke's testimony into the record as evidence?

(No response.)

COMMISSIONER BROWN-BLAND: All right. There being no objection, we will receive his testimony into evidence. I believe that his testimony consists of 14 pages filed August 13, 2013.

(Whereupon, the public version of the prefiled direct testimony of Theodore P. Pintcke was copied into the record as if given orally from the stand. The proprietary version of the testimony and exhibit has been 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	)	DIRECT TESTIMONY OF
Biennial Determination of Avoided Cost	)	THEODORE P. PINTCKE ON
Rates for Electric Utility Purchases from	)	BEHALF OF DUKE ENERGY
Qualifying Facilities – 2012	)	CAROLINAS, INC., AND DUKE
	)	ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Theodore Philip Pintcke. My business address is 11401 Lamar, Overland Park, KS 66211.

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

A. I am currently employed by Black & Veatch ("B&V") as Vice President and Senior Project Development Director.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I graduated from Michigan Technological University with a Bachelor of Science in Civil Engineering in 1976; I also periodically attend the University of Chicago Booth School of Business Executive Training. In 1976, I was employed by Black & Veatch ("B&V") as a Design Engineer, and since then, I have held positions of increasing responsibility as a Field Engineer, Engineering Manager, Project Manager, Office Manager, and Senior Project Development Director.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR CURRENT POSITION WITH B&V.

A. I am responsible for securing Expanded Scope (commonly called Engineer, Procure, and Construct or "EPC") Power Generation Projects. My primary focus is in new generation projects, particularly in combustion turbine ("CT") and coal-fired generation. I have had some experience with renewable generation technologies as well.

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

A. None, other than a copy of my current resume, which is attached as Exhibit TPP-1.

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

A. The purpose of my testimony is to discuss the cost of installing a new CT peaking plant in the current market and how that cost compares to the CT peaking plant cost estimates that were used by DEC and DEP in developing their avoided cost rates. To that end, I will first describe my background and experience in CT construction projects. Second, I will discuss the current state of the market for installation of new CTs. Third, I will explain how the construction of multiple CTs at a single site lowers the cost of installing CTs on a $/kw basis compared to building a stand-alone CT. Fourth, I will discuss my experience with the use of contingency adders and what I believe to be a reasonable level of a contingency adder as part of the project management and

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planning process. Finally, I will offer my opinion as to the cost that one would expect to incur to construct a new CT plant and show that the cost estimates used by DEC and DEP are in line with expected CT costs in the current market.

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH CT CONSTRUCTION PROJECTS AND WHAT YOUR RESPONSIBILITIES WERE FOR THOSE PROJECTS.

A. I have had direct involvement in some 25 CT projects involving engineering only, engineering and construction management, or EPC services. Most of my involvement was in securing the project work when competitively bidding the project. For a number of the projects, I also served as project director during the course of the project. Ten of the projects in which I participated involved the GE 7FA model CT, which is the type of CT that DEC and DEP used in determining their avoided cost rates.

Q. DOES YOUR CURRENT JOB REQUIRE YOU TO BE FAMILIAR WITH THE CURRENT COST TO BUILD NEW CTS?

A. Yes.

Q. HOW DO YOU STAY CURRENT WITH THE COST OF INSTALLING NEW CTS?

A. My firm bids several CT projects each year on a competitive basis and I play an active role on those to be constructed in the US and Canada. I interact several times a year with the major original equipment manufacturers

("OEMs") to stay current with CT pricing and performance upgrades. For those CT projects won by my firm, I also monitor cost as the project proceeds and at completion to best understand costs of installation and issues that can arise on a project.

Q. WHAT ARE THE COMPONENTS OF A CT CONSTRUCTION PROJECT?

A. Generally, most of the costs associated with a CT project are EPC costs. The major components of a CT peaking plant construction project are typically the combustion turbine equipment, and the generator step up ("GSU") transformers. Together, these items account for approximately 60% of the EPC cost. The rest of the EPC costs are referred to as "balance of plant" ("BOP") costs, which includes site work, pre-engineered buildings for plant operators, miscellaneous plant equipment, and the like.

Q. CAN YOU PROVIDE FURTHER EXPLANATION OF WHAT YOU MEAN BY EPC COSTS?

A. EPC costs are those costs included in the scope of the project to be supplied by a single contractor or group of contractors. The contractor's scope of work is defined for every individual contract and typically establishes the boundaries between the responsibilities of contractor and the responsibility of the owner. An example of such a responsibility between the contractor and the owner would be where the EPC scope ends at the high voltage side of the GSU transformer. EPC costs frequently include those electrical costs on the plant side of opposite the high voltage side of the GSU. Electrical costs outside this boundary, such as the switchyard or substation costs, are frequently included in what are designated as owner's costs.

Similarly, the natural gas metering and regulation station ("MRS") frequently marks the EPC boundary for gas delivery to the station. The pipeline to the site and MRS is typically included in owner's costs and all natural gas piping and connections on the plant side are included in the EPC cost.

The owner can also choose to procure the combustion turbines and GSU transformers themselves, in which case the turbines and transformers would be in the owner's cost and not in the EPC cost.

Q. **ARE YOU FAMILIAR WITH MARKET CONDITIONS IN THE CAROLINAS AND HOW SUCH LOCAL CONDITIONS MIGHT IMPACT THE COST OF BUILDING NEW CTS IN THAT REGION?**

A. Yes, I am. B&V has a large regional office located in Cary, North Carolina, and I previously served as office manager for that office from 1998 to 2003. Furthermore, I am familiar with the work B&V has performed for various clients throughout the Carolinas and surrounding states.

Q. **HOW WOULD YOU DESCRIBE THE CURRENT MARKET CONDITIONS FOR THE CONSTRUCTION OF NEW SIMPLE CYCLE CTS?**

A. Currently, few simple cycle or combined cycle projects are being built in the United States. Competition between EPC firms as well as OEMs is strong. This translates into highly competitive market pricing today.

Q. **HOW DO THE CURRENT MARKET CONDITIONS FOR THE CONSTRUCTION OF NEW CTS COMPARE TO THE MARKET CONDITIONS THAT EXISTED THREE TO FOUR YEARS AGO?**

A. In my opinion, EPC prices for combustion turbine plants have at best held flat or declined due primarily to recessionary softening in the commodity markets and a high level of competition.

In addition, efficiency gains and model upgrades in the design of combustion turbines have increased their output without proportionate increases in cost. As a result, the cost of installing new CTs has declined on a $/kw basis. I expect current pricing to remain soft for the near term.

Q. **WHAT IMPACT, IF ANY, DOES THE CONSTRUCTION OF MULTIPLE CTS ON A SINGLE SITE HAVE ON THE $/KW COST OF BUILDING THOSE CTS?**

A. Although the precise impact of installing multiple CTs at a single site will vary from project-to-project, the $/kw cost is lower when multiple CTs are constructed on a single site. There are several reasons why this is so. A number of plant features are the same regardless of the number of CTs installed at a site. There are other plant features that can be expanded with the inclusion of additional CTs at a site. The increase in cost may be less than proportionate to the increase in output. The net effect of these factors is that the cost of installing CTs at a four-unit site should be lower than the cost of installing a single CT at a site on a $/kw basis.

To illustrate this point consider some of the elements of a CT project for which the cost remains the same regardless of the number of CTs installed. These features include the plant entrance road, the administration/control building, the gas transmission line and other utilities. If the cost of these items is divided among multiple units (as opposed to being borne by a single unit), the cost of these features is reduced on a $/kw basis as more CTs are added.

In addition, there are other plant features that add an incremental cost as more units are installed at a site. In most cases, the incremental increase in cost is proportionally less than the increased output represented by the additional units. For example, a CT plant has to have a fire water system, which consists of a large fire water tank, diesel fire water pumps, underground fire water pipe line and multiple fire hydrants. If there is only one CT, it would bear the entire cost of this system. For multiple CTs at a plant, the pipeline around the added CTs may get longer, a few more hydrants may be added, and the tank and pumps may be sized larger. The increase in cost for each additional CT, however, would be less than the increase in output capacity. Stated another way, the fire water system for a four-unit CT site will be more expensive than the fire water system of a single-unit site, but it would not be four times as expensive.

Other examples of savings associated with multiple CTs at a site include detail design cost, construction management costs, construction mobilization, site fencing, plant communication system, CT control system, and transmission interconnection costs. Costs for all of these plant items should not increase significantly with the addition of CTs at a single site.

Q. CAN YOU DESCRIBE THE MAGNITUDE OF THE DIFFERENCE YOU WOULD EXPECT IN COST ON A $/KW BETWEEN THE CONSTRUCTION OF A SINGLE CT AT A PARTICULAR SITE AND THE INSTALLATION OF FOUR CTS AT A SINGLE SITE?

A. In general, I would always expect the $/kw cost for a four-unit CT site to be significantly lower than the $/kw cost of a single-unit greenfield site. To determine the precise magnitude of this cost difference would require more information regarding the project in question. However, my experience indicates that cost savings for a four-unit site over a single-unit site can be 25% or more just on BOP costs. Speaking hypothetically and without knowing whether some unusual circumstances might be involved, my 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 project.

Q. WHAT IS YOUR UNDERSTANDING OF THE PHRASE "CONTINGENCY ADDER?"

A. AACE International defines "contingency" as follows:

> [A]n amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience. Contingency usually excludes: 1) major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or

> project; 2) extraordinary events such as major strikes and natural disasters; 3) management reserves; and 4) escalation and currency effects.

Cost Engineering Terminology, AACE International Recommended Practice No. 10S-90, April 25, 2013 at 21. Some of the items, conditions, or events for which the state, occurrence, and/or effect is uncertain include, but are not limited to, planning and estimating errors and omissions, minor price fluctuations (other than general escalation), design developments and changes within the scope, and variations in market and environmental conditions. Contingency is generally included in most estimates, and it should be set at a level at which is reasonably expected to be incurred as part of the cost of the project.

Q. IS THE AMOUNT OF THE CONTINGENCY ADDER USED AFFECTED BY THE NATURE OF THE PROJECT INVOLVED?

A. Yes. The amount of contingency is highly correlated with the nature of the project. A first-of-its-kind project or technology would require a larger contingency amount due to the inherent uncertainty in a new project or technology. A mature, developed technology that has been executed many times in the past with favorable results (such as GE 7FA) would generally require a lesser contingency amount. Nonetheless, even a mature technology could require a larger contingency if the project has not been well-defined and the boundaries between EPC and owner's costs have not been clearly established.

Q. **IN YOUR OPINION, IS THE CONSTRUCTION OF A SIMPLE CYCLE CT THE TYPE OF PROJECT THAT WOULD WARRANT A HIGH CONTINGENCY ADDER?**

A. Since it is not a first time or new technology, I do not believe that a high contingency adder is needed. B&V has completed numerous simple cycle projects world-wide. In my experience, for the reasons I discuss earlier, in the absence of extenuating circumstances, B&V would typically not include a high amount of contingency for a simple cycle CT project, particularly on proven equipment.

Q. **BASED ON YOUR EXPERIENCE, WHAT CONTINGENCY ADDER SHOULD BE USED TO DEVELOP AN ESTIMATE OF THE LIKELY COST OF BUILDING FOUR SIMPLE CYCLE CTS AT A SINGLE SITE?**

A. Assuming a lump sum EPC estimate for a well-defined project with the owner providing the CT equipment and GSU transformers and assuming the EPC contract consists of reasonable contract terms and a normal project schedule, I would typically recommend a 4-8% contingency amount. The specific amount is influenced by the market, the location of the project, labor availability and conditions at the time, legal and regulatory requirements.

Q. **WHAT ARE THE FACTORS THAT LEAD YOU TO CONCLUDE THAT A 4-8% CONTINGENCY ADDER IS AN APPROPRIATE FOR THE DEVELOPMENT OF A FOUR UNIT CT SITE?**

A. It is based on my experience at B&V with the numerous simple cycle projects worldwide using the GE 7FA CT. This has given us a solid history of forecasting the expected quantities of materials, equipment, and labor costs to implement this technology with a generally high degree of confidence.

Q. **BASED ON YOUR EXPERIENCE, HOW MUCH WOULD IT LIKELY COST DEC OR DEP TO BUILD FOUR GE 7FA.05 CTS AT A SINGLE SITE?**

A. In my opinion, a new four unit GE 7FA.05 project could be developed for approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This is an overnight cost, which does not include allowance for financing. For comparison purposes, my understanding is that the overnight cost estimate I developed is comparable to the overnight cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that DEC and DEP used in their avoided cost rates.

Q. **HOW DID YOU DERIVE THAT ESTIMATED COST?**

A. I was able to complete an independent overnight BOP cost estimate for a new four-unit CT plant in North Carolina, assuming use of General Electric's 7FA combustion turbines using prices from historical data on quantities, equipment, labor hours and cost to design and construct along with North Carolina wage and productivity rates.

I applied an estimate of owner's cost provided by DEC and DEP. I also developed an estimate of current cost for the BOP and adjusted the productivity and wage rates to a North Carolina location to estimate labor costs. I accounted for the use of common facilities between the four units and based all costs on 2013 levels. I assumed open shop labor as commonly used in North Carolina. My estimate of BOP costs was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which included a 10% or greater contingency. I added: 1) the BOP cost; 2) the cost of the turbines and GSU transformers (as estimated by DEC and DEP and verified by B&V); and 3) the allowance for owner's cost estimated by DEC and DEP, to arrive at a range of total cost.

Q. ASSUMING THAT EACH GE 7FA.05 HAS A RATED CAPACITY OF 201.2 MW, HOW MUCH DO YOU ESTIMATE IT WOULD COST TO BUILD FOUR SUCH UNITS AT A SINGLE SITE ON A $/KW BASIS?

A. For the design and procurement of the BOP equipment and construction, I estimated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. For the turbines and GSUs, I estimated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The allowance for owner cost provided by DEC and DEP was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Thus, my total overnight cost estimate for a four GE 7FA.05 units at a single site was unit site is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. HOW DOES THE COST ESTIMATE THAT YOU DEVELOPED COMPARE TO THE COST ESTIMATES THAT DEC AND DEP USED IN DEVELOPING THE AVOIDED CAPACITY RATES THAT THEY HAVE PROPOSED IN THIS DOCKET?

A. As I noted above, my understanding is that DEC and DEP both used an overnight cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for purposes of calculating their avoided cost rates. Thus, my estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is 7% less than the estimate used by DEC and DEP.

Q. WERE YOU AWARE OF THE CT COST ESTIMATES USED BY DEC AND DEP IN THEIR AVOIDED COST CALCULATIONS WHEN YOU DEVELOPED YOUR CT COST ESTIMATE?

A. Yes, I was aware of their cost estimate. However, I based my estimate on historical data coupled with recent market pricing. For today's market and the scope as I understand it, I believe that the cost provided by DEC and DEP and their consultants is conservative. Market conditions may change in the future causing a revision to my estimate. However, based on my current understanding, the cost is sufficient to support construction of a four-unit combustion turbine plant at locations generally suitable for construction of a CT peaking plant.

Q. AFTER YOU BECAME AWARE OF THE CT COST ESTIMATES USED BY DEC AND DEP IN THEIR AVOIDED COST CALCULATIONS, DID YOU MODIFY YOUR COST ESTIMATE?

A. No. My estimate was completed based on a more detailed breakdown of costs than provided by DEC and DEP, utilizing my knowledge of prior B&V projects and pursuits with similar CT technology.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM COMPARING THE CT COST ESTIMATES USED BY DEC AND DEP IN THEIR AVOIDED COST CALCULATIONS WITH YOUR CT COST ESTIMATE?

A. The overnight cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for a new four-unit, 805 mw CT project is slightly high (7%) given current market conditions for combustion turbine plant materials and equipment.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. FENTRESS: And an exhibit as well was attached to his testimony and we would move that into the record as well if there are no objections from counsel.

COMMISSIONER BROWN-BLAND: And that one exhibit attached to his direct testimony will also be received and marked as it was when it was prefiled. That testimony is confidential testimony and shall remain so for purposes of the transcript.

(Whereupon, Exhibit TPP-1 was identified as premarked and admitted into evidence.)

MS. FENTRESS: And just to note, although it may not clearly state, the Settlement Agreement that we have passed out to the parties that are subject to our confidentiality agreement and to the Commission does contain confidential information which is -- which is marked within the agreement.

COMMISSIONER BROWN-BLAND: All right.

MS. FENTRESS: And if I might ask one other procedural matter? Because of the unusual timing of this, we would like to have Ms. Bowman start as our witness and proceed with a summary of the Settlement and a summary of her direct, and then we would allow the intervenors to put forth their case. And then we would again put up Ms. Bowman and Mr. Snider on direct and Mr. Snider will give direct testimony as well.

COMMISSIONER BROWN-BLAND: All right.

MS. FENTRESS: And rebuttal after the intervenors. I'm sorry.

COMMISSIONER BROWN-BLAND: Ms. Bowman to give rebuttal?

MS. FENTRESS: Ms. Bowman and Mr. Snider will give rebuttal --

COMMISSIONER BROWN-BLAND: After intervenors?

MS. FENTRESS: -- and they will give direct prior to the intervenors. But they will also give a summary of the Settlement Agreement prior to giving their direct testimony.

COMMISSIONER BROWN-BLAND: And they want to do their rebuttal after the intervenors or --

MS. FENTRESS: They do.

COMMISSIONER BROWN-BLAND: All right.

MS. FENTRESS: If it's the Commission's wish.

COMMISSIONER BROWN-BLAND: Okay. You've heard her representations. Are there any objections or differences of opinion before we move forward?

(No response.)

COMMISSIONER BROWN-BLAND: There being no --

there being no objections, we will move forward. Did -- Ms. Kells, did you want to get anything on the record before we move forward with the Dukes' case?

MS. KELLS: Yes, Commissioner. Dominion has also entered into a stipulation with Public Staff on the issues of CT cost and the PAF and Option B. It has been executed but not yet filed.

And we also, as I understand it, plan to enter into a stipulation with the REG Group pertaining to the same issues, which that would be CT cost and Option B or PAF. We have not yet executed that agreement.

And so we have -- Dominion and Public Staff have agreed not to cross-examine each other's witnesses pursuant to the stipulation between the parties. And REG and Dominion will still cross-examine each other's witnesses on the remaining issue between them of Article 6 or Regulatory Disallowance Clause is my understanding, although we've not executed that as of yet.

And as Ms. Fentress suggested, Dominion would also like to put up its Mr. Petrie and Mr. Trexler on their direct testimony and then after the intervenors have been cross-examined put them up for cross-exam on their rebuttal.

COMMISSIONER BROWN-BLAND: All right. Thank you. Does anyone have anything to add to those representations?

(No response.)

COMMISSIONER BROWN-BLAND: All right. Before we do get started into the testimony --

MR. YOUTH: Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Yes, Mr. Youth.

MR. YOUTH: This may be the wrong time to ask this, but before I forget I think all the parties have stipulated that prior filings like comments, replies would be stipulated into the evidentiary record. So I would ask at least for NCSEA's prior filings to be stipulated into the record.

COMMISSIONER BROWN-BLAND: As -- you want it in the record as evidence?

MR. YOUTH: Yes, please.

COMMISSIONER BROWN-BLAND: Is that the understanding of the parties or is there any objection?

MS. FENTRESS: We did have an objection to Mr. -- to the NCSEA's supplemental filing of Mr. Rabago's testimony and exhibit. We will make that objection at the appropriate time.

COMMISSIONER BROWN-BLAND: And otherwise, no objection? That being the case, we will receive the comments of NCSEA that were filed -- prefiled in this docket as evidence in this case.

(Whereupon, the public version of NCSEA's Comments and exhibits were admitted into evidence. The proprietary version has been filed under seal.)

COMMISSIONER BROWN-BLAND: Does anyone else at this time wish to move their contents into evidence?

MS. RANKIN: The Public Staff would like its initial statement and its reply comments copied into the record as evidence.

COMMISSIONER BROWN-BLAND: Very well. The Public Staff's initial statement and reply comments will be received into evidence in this docket.

(Whereupon, the public version of Public Staff's Initial Statement and Reply Comments were admitted into evidence. The proprietary version was filed under seal.)

MS. MITCHELL: The Renewable Energy Group would like to move its initial statement and the affidavit of Don Reading into the docket, received as evidence.

COMMISSIONER BROWN-BLAND: All right. REG's initial statement and the affidavit of Don Reading will be received into the record as evidence. The affidavit will be treated as if it was given orally from the stand.

(Whereupon, Renewable Energy Group's Initial Comments were admitted into evidence.)

(The public version of the affidavit of Dr. Don Reading was copied into the record as if given orally from the stand. The proprietary version of the affidavit has been 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	)))	**AFFIDAVIT OF DR. DON READING**

The undersigned, Dr. Don Reading having been duly sworn, deposes and says as follows:

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

2. I am a consulting economist and V.P. of Ben Johnson Associates, Inc. I hold a PhD in economics from Utah State University, an MS in Economics from the University of Oregon, and a BS in Economics from Utah State University. I taught Economics at Middle Tennessee State University, Idaho State University, and the University of Hawaii at Hilo. I have worked in the area of utility regulation as Staff Director for the Idaho Public Utilities Commission, and as a private consultant for more than 30 years. My resume is attached.

3. My work has spanned a wide range of different subject areas, involving the application of economic theory and principles to public policy issues involving the electric, gas, water, wastewater, and telecommunications industries. My interest in the electric utility industry began in the late 1970s and early 1980s, leading me to work for the Idaho Public Utilities Commission, where I served as an Economist and Director of

Policy and Administration (somewhat analogous to the position held by Mr. Robert Gruber in North Carolina).

4. I have provided expert testimony in proceedings in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Carolina, North Dakota, Texas, Utah, Wyoming, and Washington.

5. Since 1999 I have been affiliated with the Climate Impact Group ("CIG") at the University of Washington. My work with the CIG has involved an analysis of the impact of Global Warming on hydroelectric facilities on the Snake River, an investigation into water markets in the Pacific Northwest and in Florida, and various other topics.

6. I have prepared econometric forecasts for the Southeast Idaho Council of Governments and for the Revenue Projection Committee of the Idaho State Legislature. I have been a member of several Northwest Power Planning Council Statistical Advisory Committees. I was the vice chairman of the Governor's Economic Research Council in Idaho and have performed research projects for the Idaho Governor's Office.

7. While most of my work with Ben Johnson Associates, Inc. has been concentrated in the Pacific Northwest, I have participated in the following proceedings before the North Carolina Utilities Commission: i) Docket No. E-2, Sub 537, a 1986 Carolina Power & Light rate case in which we assisted Public Staff with reviewing the prudence of the Shearon Harris nuclear plant; ii) Docket No. E-100, Sub 58, a 1988 proceeding concerning avoided costs; iii) Docket No. E-100, Sub 75, a 1995 proceeding concerning Least Cost Integrated Resource Planning; and iv) Docket No. E-2, Sub 760, the 2000 proceeding in which CP&L Holdings, Inc. requested permission to acquire Florida Progress Corporation. I also provided testimony on behalf of EUNC in Docket Nos. E-

100, Sub 124, involving integrated resource planning, and E-2, Sub 996, involving the calculation of avoided cost.

8. Ben Johnson Associates, Inc. has been retained by the Renewable Energy Group ("REG") to examine the filings of Duke Energy Carolinas, LLC ("DEC" or "Duke"), Progress Energy Carolinas, Inc. ("PEC" or "Progress"), and Dominion North Carolina Power ("DPNC" or "Dominion") (collectively, the utilities) in Docket No. E-100, Sub 136. To this end, this affidavit sets forth the results of my analysis as well as my conclusions.

9. I have reviewed the initial filings of DEC, PEC, and DNCP, along with the data request responses of the parties involved in this Docket, as well as the following:

a. Filings made in Docket E-100, Sub 137.

b. Filings made in Docket E-100, Sub 127.

c. Filings made Docket E-100, Sub 128.

d. Black & Veatch Cost Report.

e. Reports and Studies provided in response to data requests.

f. Annual Reports and FERC Form 1s of the utilities.

10. Based on my review of the foregoing, the Commission should instruct the utilities to recalculate their filed avoided cost rates based on the following assumptions:

(a) DEC

(i) Capital cost of CT: [redacted] $/kW.

(ii) Contingency: the same as that used in Docket No. E-100, Sub 127 in 2010.

(iii) Investment Life: [redacted] (the same that DEC used in Docket No. E-100, Sub 127 in 2010.)

(b) PEC

(i) Capital cost of CT: The $/kW value used for a CT in PEC's 2012 IRP filing.

(ii) Contingency: the same as that used in Docket No. E-100, Sub 127 in 2010.

(iii) Investment Life: [redacted] (the same that PEC used in Docket No. E-100, Sub 127 in 2010.)

(c) DNPC

(i) Capital cost of CT: [redacted] $/kW

11. There has been a significant decline in the rates associated with the both the capacity credit and energy credit of the avoided cost rates proposed by the three utilities. DEC's proposed annualized energy rates are 7% lower, and its annualized capacity rates are 29% lower than those approved by the Commission in Docket E-100, Sub 127. PEC's proposed annualized energy rate is 20% lower and the annualized capacity rate 25% lower than those approved by the Commission in Docket E-100, Sub 127.

12. As displayed below in Figure 1 and Figure 2 the dramatic decrease in annualized avoided cost rates, as proposed by both DEC and PEC, has reversed a general 25 year trend upward trend. This is the first time DNCP has used the peaker method, which has been the approved method by the Commission for the other two utilities for the determination of avoided cost, therefore there is not a comparable history for DNCP.

Figure 1

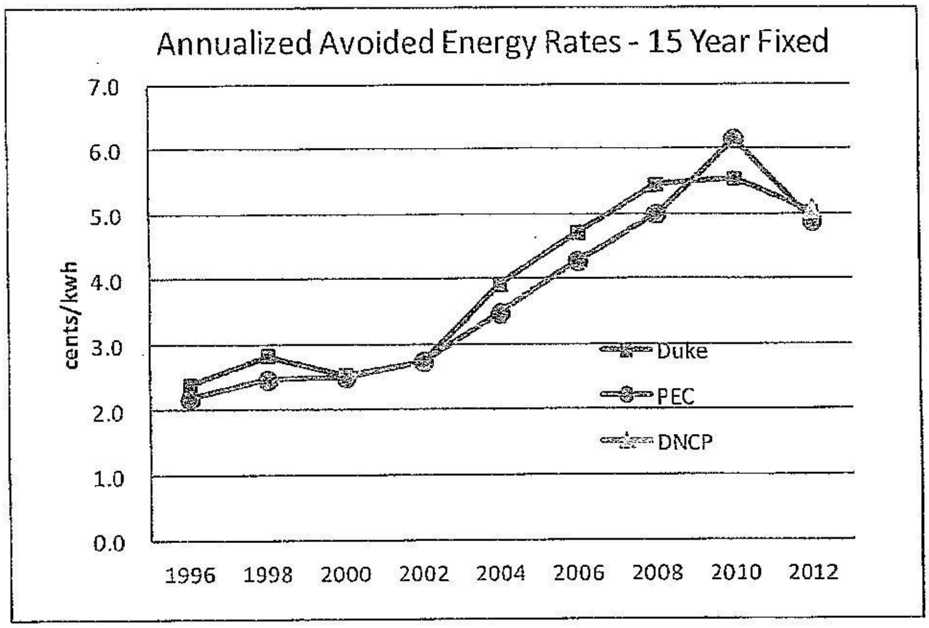
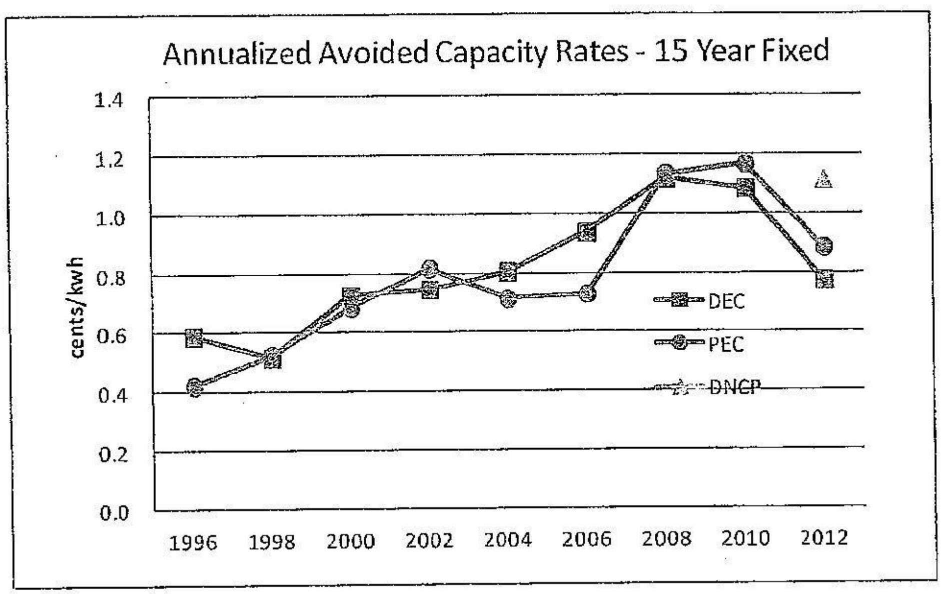


Figure 2



13. DNCP, PEC, and DEC have essentially the same annualized energy rates. However DNCP's avoided cost rate filed this year for the first time using the peaker method is close to that of PEC and DEC approved by the Commission in Docket No. E-100, Sub 127.

14. According to Duke, the primary drivers causing this decrease in its avoided cost rates are [redacted]

a. Lower natural gas prices;

b. Higher assumed ratings for the avoided CT units without a significant increase in the total cost of the units; and

c. Increase in the assumed life of the avoided CT units from [redacted] for PEC and from [redacted] for DEC.

15. In addition, the utilities have significantly decreased the contingency allowance assigned as part of CT capital costs from that used in Docket No. E-100, Sub 127.

16. Given the current historically low natural gas prices, a decrease in the rates associated with the energy credit of the proposed avoided cost rates is expected. However the nearly 30% drop in capacity rates from just two years ago is not justified for the reasons discussed below.

17. In the calculation of avoided cost rates filed in this Docket, each of the utilities used the following assumptions as the major drivers of their proposed rates:

a. DEC

i. Capital Cost $/kW: [redacted] [NCPS DEC Data Request #1 – Response 1-2D &2E]

ii. Fixed O&M $/kW: [redacted] [NCPS DEC Confidential Exhibit 4]

iii. Fixed Rate Charge: [redacted] [NCPS DEC Confidential Exhibit 4]

iv. Investment Life: [redacted] [NCPS DEC 2(a) FCR Model]

b. PEC

i. Capital Cost $/kW: [redacted] [PEC.Staff DR-1 Attach 1, tab Cap_Carry_Cost, 2013]

ii. Fixed O&M $/kW: [redacted] [PEC.Staff DR-1 Attach 1, tab Fixed O&M]

iii. Fixed Rate Charge: [redacted] [PEC.Staff DR-1 Attach 1, tab Cap_Carry_Cost, 2013]

iv. Investment Life: [redacted] [PEC.Staff DR-1 Attach 1, tab Input Ranges]

c. DNCP (first time use of peaker method)

i. Capital Cost $/kW: [redacted] [NCPS DNCP Data Request 1-2cdeg JGM]

ii. Fixed O&M $/kW: [redacted] [NCPS DPNC 2-1.]

iii. Fixed Rate Charge: [redacted] [[redacted], NCPS DNCP Data Request Set 1-1(I) (RCR)]

iv. Investment Life: [redacted] [NCPS DNCP Data Request 1-2F]

18. Each of the three utilities has filed with the Commission their biennial 2012 Integrated Resource Plans ("IRP") Studies in Docket No. E-100, Sub 137. The IRPs are then used by the utility in the development of their planned future resource strategy in order to meet expected loads. The value used for the cost of future generation plant projected by a utility defines the long-run avoided costs of the utility at the time the IRP

is filed at the Commission. The utilities' IRP filings preceded the filing of their proposed avoided cost rates by just two months. Therefore the cost data for the CT used in this Docket to find avoided cost should match those costs found in the IRP filed just two months earlier. However, that is not the case. The CT costs used in the IRPs are significantly higher than those used in determining avoided cost, and these differences are a major factor in the decline in avoided cost rates proposed by the utilities in this Docket.

19. The following table—illustrating the difference between the cost of a CT filed in its IRP and in this proceeding—was provided by DEC. [NCPS DEC Data Request #1 – Response 1-2D &2E]

[redacted]

The $/kW total project cost used in DEC's 2010 avoided cost filing was [redacted], and, in the 2012 avoided cost filing, it dropped by 30% to [redacted]. In DEC's 2012 IRP, the total project cost increased by 7% to [redacted] from the total project cost used for avoided cost calculations in 2010. DEC stated:

> In addition to the "worst case" owner's contingency, an additional adder was inadvertently included in the 2012 IRP estimate, thus unnecessarily inflating the contingency of all technologies. [NCPS DEC 1-1, 2(E)]

According to Duke the "adder removed" indicated in the above table was [redacted] "inadvertently included in the 2012 IRP estimate." [DEC REG DR 3-6] This would mean only a $.044 difference on a $/kW basis, hence the reduced contingency accounts for the almost all of the difference between DEC's 2012 IRP value and the adjusted 2012 IRP value. The [redacted] per kW cost indicated in the table above is even lower than the [redacted] per kW CT cost used by DEC as a "screening" value in the Company's 2010 IRP process. [REG 2-3 2010 DEC IRP Screening Model Rev4_Confidential] As discussed below there is no valid reason to lower the contingency percentage from past practice. Therefore, I recommend that the 2012 IRP CT cost of [redacted] per kW should be used in the calculation of avoided cost rates for Duke. At the very least the [redacted] per kW used by DEC in its 2010 avoided cost filing should be used in this case.

20. The North Carolina Public Staff asked DEC, based on the table below, to explain and justify the differing capital cost values of a CT as filed by the Company in this avoided cost proceeding and in the IRP proceeding since 2006 as displayed in the table below. [NCPS DEC 3-1]

[redacted]

Most of the explanation for the capital cost differences revolved around adjustments for the number of CTs per site as presented by various sources such as EIA, GTW, and EPRI. DEC concluded:

> Comparison of the CT capacity cost estimates to multiple other data sources including EIA, GTW, Brattle Group, EPRI, and self-build projects demonstrates that the capital cost data used in the Company's 2012 avoided cost filing is in-line with, and in some cases greater than, the multiple other price points cited. The Company believes the capacity cost used in its avoided cost filing is within a reasonable range.

What is interesting to note in the table above is, as would be expected, the two years when the IRP capital cost was less than that used by DEC to calculate avoided cost rates did not include AFUDC in the $/kW estimates (2008 and 2009). Note also the percentage differences between DEC's avoided cost estimates and IRP capital cost estimates, reflected on Figure 3 below. In this proceeding, the avoided cost estimate is [redacted] lower than the corresponding IRP value, which is twice the percentage difference than the other three years.

[redacted]

Figure 3.

Regardless of the number of CTs per site, the capital cost used by DEC to justify the selection of the DEC's future resource mix found in DEC's preferred portfolio is the IRP cost of [redacted] per kW.

21. In a discovery response to Public Staff, Duke makes the claim that, "The Company believes the capacity cost used in its avoided cost filing is within a reasonable range." [NCPS DEC 3, p. 6.] DEC justifies this claim by citing four outside sources and the experience of PEC's CT construction projects indicating lower costs and justifying a lower contingency factor. Duke massages the CT $/kW estimates from the four outside studies – EIA, GTW, Brattle, EPRI – to account for, depending on the study, inflation, engineering, construction, ownership and contingency costs. The biggest adjustment for the capital costs of a CT published by the outside studies made by DEC is an adjustment in cost from a 1, 2, or 3 unit site estimate to a 4 unit site. For example, DEC says based on the B&M studies they reduced the EIA estimate from [redacted] per kW.

These adjustments made by DEC are arbitrary and not based on site or specific design criteria for what would eventually occur at a site used for 4 units. The low contingency percents used in these adjustments are the same as that filed by the utilities in this avoided cost docket. System loads have flattened and an examination of DEC's expansion plans indicates that the next CT units planned are six years in the future with 800 MW CT in 2019, and then not again until 2030. For PEC the next CT in their expansion plan in 2016 is the single unit discussed in 25 above. Following that CT PEC projects the next CT units in 2018 at 370 MW followed by another 185 MW in 2019, then 185 MW CTs in 2026 and 2027.

The explanations by DEC do not remove the inconsistencies pointed out about in the wide variety of CT cost estimates.

22. The [redacted] per kW CT cost used by DEC in calculating capacity cost in this proceeding is at odds with the capital costs indicated in other third party evaluations for the utility. Duke Energy Carolinas 2012 Reserve Margin Study by Astrape Consulting (8/17/2012) [REG 2-4 DEC Res Mar Report Final] produced a generic CT cost of [redacted] per kW in 2016 dollars. Assuming an 2.5% inflation rate (used by DEC) discounted to the present value would yield a CT cost of over [redacted] per kW, or an amount [redacted] higher than that used by DEC in its calculations of proposed avoided cost rates in this Docket.

23. PEC's CT cost of [redacted] per kW used in the calculation of proposed avoided costs rates is 6% lower than that used by DEC in determining its proposed avoided cost rates.

24. PEC's avoided cost filed in its 2012 IRP—just two months before the avoided costs rates proposed by the Company were filed in this docket—forecast that there would be no change in PEC's avoided cost rates through 2014, as depicted in the table below.

Progress Energy Carolina's, Inc.'s 2012 Integrated Resource Plan, Filed September 4, 2012, Appendix D-7, VII.

Table 7: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.786¢	5.786¢	5.786¢
5 Year	6.184¢	6.184¢	6.184¢
10 Year	6.816¢	6.816¢	6.816¢
15 Year	7.286¢	7.286¢	7.286¢

In stark contrast, in this proceeding, capacity rates proposed by PEC are 22% to 27% lower than the current capacity rates, and energy rates are 15% to 29% lower. [NCPS PEC DR-1 Attach 1, tab Comparison.]

25. Public Staff asked PEC to justify the CT cost differences between those filed in avoided cost proceeding and those used in the IRP proceeding. [NCPS PEC 2] PEC's response was essentially the same as DEC's response to the same question from Public Staff. In fact, the vast majority of PEC's response is word for word with DEC's, referencing the same information as was referenced in DEC's response. The conclusion was identical in both responses.

26. PEC's 2012 Reserve Margin Study prepared by Astrape Consulting does not have a CT cost on a $/MW basis. However it states, for a generic CT, a first unit ECC+Fixed O&M of [redacted] $/kW-yr, and [redacted] $/kW-yr (average [redacted]) [REG DR 2-4 Progress RM Report Final, p. 58] PEC, however, disavows use of the cost data found in its own August 2012 Reserve Margin Study. In a data response PEC stated,

> The combustion turbine cost data used for the Avoided Cost filing was based on new third party studies, which are more current than the vintage 2011 data provided for the Astrape study. Since the Avoided Cost filing is

simply based on more current CT data, the requested calculations were not performed and therefore are not available. [NCESA PEC 2-1 Response]

As demonstrated above, the utilities have a wide range of construction costs for a CT, yet they have picked from the bottom of the range of CT costs for use in calculating proposed avoided cost rates, thus resulting in a significant decrease from currently approved avoided cost rates.

27. As an additional point of reference, PEC's 2012 IRP indicates the next CT slated for construction is an "undesignated" to be on-line in December 2016. REG asked Progress to indicate the type of CT, and its costs, for this "undesignated" next unit. The data request to PEC and PEC's response are as follows:

5. For purposes of the following questions, with respect to proposed avoided capacity credit rates filed by Progress Energy Carolinas, Inc. ("PEC" or the "Company") in Docket No. E-100, Sub 136:

On page 25 of the Company's Public Version of its 2012 Integrated Resource Plan filed in Docket No. E-100, Sub 137, the Table lists an undesignated 126 MW CT with an in-service date of 12/16. Please provide support for the expected installed cost. The response should include the anticipated heat rate (for both summer and winter) and start costs. Please indicate if the estimated installed costs include land and interconnection costs.

[redacted]

[redacted]

In data accompanying the above response, the capital cost of this [redacted] Combustion Turbine was [redacted] kW for a greenfield site, and [redacted] per kW for a brownfield site. I am not advocating the use of PEC's proposed next CT unit within three years for the calculation of avoided capacity cost rates here, but have presented this data to show the wide disparity in CT capital cost estimates, hence the somewhat arbitrary nature of these CT cost estimates.

28. DNCP uses the highest estimated CT construction cost among the three utilities filing proposed rates in this Docket at [redacted] per kW. [NCPS DNCP Data Request 1-2F] However, as is the case for PEC and DEC, this capital cost value is low and not consistent with collaborating cost estimates.

29. In a response to Public Staff's data request 2-1, DNCP responded:

> Question No. 1:
>
> Please provide Dominion's overall installed cost per kW for a CT located at a greenfield site.
>
> [redacted]

[redacted]

30. Both PEC and DEC, for this filing, have reduced the contingency to [redacted] [NCPS DEC Avoided Cost DR 2 Response Final] from that used in the 2010 avoided cost filings. As pointed out above in paragraph 19 above, the reduction in contingency has had a significant impact on the capital cost estimates and hence lowers the capacity credits proposed by the two utilities. According to DEC the reason for this decrease in the contingency component of CT cost estimates is:

a. Economic Conditions:

[redacted]

b. Economies of Scale:

[redacted]

c. Experience:

[redacted]

[redacted]

d. Third Party Studies:

[redacted]

[NCPS DEC 1-1 (2)]

The economic conditions of the 2008 downturn certainly created a time of uncertain conditions of the future of resource costs. However, today's economy is also fraught with significant uncertainty. The DJIA on Friday, February 1, 2013 reached 14,000 for the first time since the fall of 2007, and assuming the recovery continues it will bring upward pressure on commodity prices and the cost manufactured goods. Congress and the President have still not been able to put together a plan to solve our current fiscal crisis. In an increasing global economy, Europe's unsolved austerity and Euro problems can have a major impact on the economy of the United States. And China's growth path, with its demand for resources along with its emerging labor and pollution problems, has potentially important impacts on the world's industrial economies. Today's risky economic and energy future do not justify reducing contingency risk from that of five years ago when the United States was entering the recession.

31. DEC also cites recent CT projects currently underway, and the experience gained from the construction, as a reason for reducing its contingency component of CT cost estimates. However, as detailed in a recent Black & Veatch Cost Report for non-site and specific design projects it is not unreasonable to have contingencies in the 20 to 30% range.

> Another form of variability that exists in estimates concerns the use of different classes of estimate and associated types of contingency. There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site -specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site -specific differences. [Cost Report: Cost and Performance Data for Power Generation, Black & Veatch for NREL, February, 2012, p.8.]

[redacted]

32. The investment life of the CT used to calculate avoided cost rates by PEC has increased from [redacted] years and from [redacted] years for DEC. As pointed out in paragraph 14 above, this assumed increase in investment life has had a major impact in

the reduction of the proposed capacity rates. An examination of the emails exchanged between DEC and PEC indicates the investment life was still undecided and subject to change just a week and a half before their filings in this case. Also obvious from the emails is the two companies' desire to have the same investment lives of the CT used for the purpose of calculating avoided costs. However, there does not appear to have been an effort to make equal the CT capital costs.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

It appears that DEC's decision to extend the investment lives of the CTs for the purpose of the avoided cost calculation was arbitrary and not based on rational studies of a realistic useful life of a CT. PEC has a new deprecation study using a [redacted] year life. However, DEC's fixed asset group stated they had no backup for a useful life and the study did not list useful lives. Given the lack of convincing data presented in this case relative to the one filed in 2010, there is no valid reason to extend the investment life for DEC beyond [redacted] years and PEC beyond [redacted] years.

33. As demonstrated above, PEC and DEC have a wide range of construction costs for a CT and a history of Commission approval of significantly higher capital costs in previous avoided cost proceedings. Yet, in this proceeding, they have picked from the bottom of the range of CT capital costs for use in calculating proposed rates, resulting in a significant drop from currently approved rates. PEC and DEC have been arbitrary and inconsistent on big drivers of avoided costs and in this proceeding worked together to pick the lowest costs in most instances without reason other than to make avoided costs rates lower.

34. The Commission should instruct the utilities to recalculate their proposed avoided cost rates based on the following assumptions:

(a) DEC

(i) Capital cost of CT: [redacted] per kW

(ii) Contingency: the same as that used in Docket No. E-100, Sub 127 in 2010

(iii) Investment Life: [redacted] years (the same that DEC used in Docket No. E-100, Sub 127 in 2010.)

(b) PEC

(i) Capital cost of CT: The per kW value for a CT used in PEC's 2012 IRP filing

(ii) Contingency: the same as that used in Docket E-100, Sub 127 in 2010

(iii) Investment Life: [redacted] years (the same that PEC used in Docket E-100, Sub 127 in 2010.)

(c) DNPC

(i) Capital cost of CT: [redacted] per kW

FURTHER THE AFFIANT SAYTH NOT.

This the 7th day of February, 2013.

Don Reading

Sworn to and subscribed before me
this the 7th day of February, 2013.

Notary Public

My commission expires: 10/21/2016

JENNIFER B. OUTRAM-DOBLER
NOTARY
PUBLIC
STATE OF IDAHO

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Don C. Reading, PhD

Present position: Vice President and Consulting Economist

Education:
- B.S., Economics C Utah State University
- M.S., Economics C University of Oregon
- Ph.D., Economics C Utah State University

Honors and awards: Omicron Delta Epsilon, NSF Fellowship

Experience:

Ben Johnson Associates, Inc.:

1989 ---- Vice President

1986 ---- Consulting Economist

Idaho Public Utilities Commission:

1981-86	Economist/Director of Policy and Administration
Teaching:	
1980-81	Associate Professor, University of Hawaii-Hilo
1970-80	Associate and Assistant Professor, Idaho State University
1968-70	Assistant Professor, Middle Tennessee State University

Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 45 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, North Carolina, Oregon, Texas, Utah, Wyoming, and Washington.

Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates.

In the field of telecommunications, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.

Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature's Committee on Electric Restructuring.

Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming.

Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho. He is currently a Public Works Commissioner for the City of Boise.

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination. He is currently a adjunct professor of economics at Boise State University (Idaho economic history, urban/regional economics and labor economic.)

Dr. Reading has recently completed a public interest water rights transfer case. He has also just completed an economic impact analysis of the 2001 salmon season in Idaho.

Publications:
"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006.
www.boisestate.edu/history/issuesonline/fall2006_issues/index.html

The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003.

The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999.

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997.

A Cost Savings from Nuclear Resources Reform: An Econometric Model@ (with E. Ray Canterbery and Ben Johnson) Southern Economic Journal, Spring 1996.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983.

An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980.

Phosphate and Southeast: A Socio Economic Analysis (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975.

"A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In The American Economist, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128.

"New Deal Activity and the States, 1933-1939." In Journal of Economic History, Vol. XXXIII, December 1973, pp. 792-810.

MS. FENTRESS: DEC and DEP would like to move into the record its Initial Statement, its Reply Comments and -- comments and reply comments.

COMMISSIONER BROWN-BLAND: All right. Those will be received into the record as well as evidence.

(Whereupon, the public version of Duke Energy Carolinas and Progress Energy Carolinas Joint Reply Comments were admitted into evidence. The proprietary versions have been filed under seal.)

MS. KELLS: And Dominion would also like to move into the record its previous filings in this proceeding, particularly its reply comments and initial statement.

COMMISSIONER BROWN-BLAND: All right. They will be received as well, Ms. Kells.

(Whereupon, the Reply Comments of Dominion North Carolina Power were admitted into evidence.)

Now, before we move further, in this document there has been quite a lot of testimony that has been filed under seal and contains trade secrets. And those will remain so as we proceed throughout. But if we get to a point in the hearing where questions need to be asked pertaining to confidential information and they cannot be worded in such a way that we avoid revealing that information, then at that point in time we will ask all those parties who have not signed the appropriate nondisclosure agreements to leave the room and we will have questions on the confidential materials at that time.

And what I intend to do is to have non-confidential cross-examination first and we will go through all of the parties who wish to do cross-examination of a particular witness and then we'll have redirect on the non-confidential. Then, we will clear the room for any questions on confidential -- cross-examination on confidential information followed by redirect on confidential followed by Commission questions on confidential. Then we will open the courtroom back up to the public and the Commission will complete any questions it had on non-confidential materials. And if that's acceptable, that's the way we'll proceed.

I would also caution that as we were reviewing these materials we noticed that in confidential versions, which the Commissioners tend to have confidential versions, not all the confidential versions marked everything that was redacted from the public version. And so I would caution the Commissioners, but also the parties, to pay attention and be responsible and alert us if -- if information -- we appear to be getting into confidential information and we need to make adjustment.

That being said, Ms. Fentress, you can call your witness, or Mr. Somers can call his witness.

MS. FENTRESS: We would call Ms. Bowman to the stand, please.

MR. YOUTH: Commissioner Brown-Bland, were there going to be -- was there going to be an opportunity for opening statements?

COMMISSIONER BROWN-BLAND: Oh, I'm sorry. I forgot. Do we want -- do the parties still want to do opening statements?

MR. YOUTH: NCSEA would like five minutes.

MS. FENTRESS: I believe I can do a brief opening statement.

COMMISSIONER BROWN-BLAND: All right. I'm sorry about that, Ms. Bowman. We will now have opening statements. I believe amongst yourselves you've already decided the length of time and the order.

MS. FENTRESS: Yes. I think we'll have about five minutes.

COMMISSIONER BROWN-BLAND: All right. Ms. Fentress, we will hear from you.

MS. FENTRESS: Thank you. For Duke Energy and Duke Energy Progress, this avoided cost proceeding has focused on two main issues.

COMMISSIONER BROWN-BLAND: Ms. Fentress, if you'd pull that mic a little closer to you?

MS. FENTRESS: This avoided cost proceeding has focused on two main issues. The combustion turbine or CT cost estimates used to calculate the Companies' avoided capacity cost and whether the Performance Adjustment Factor for wind and solar QFs should be increased from 1.2 to 2.0. As their comments and testimonies demonstrate, Duke Energy Carolinas and Duke Energy Progress based their avoided cost rates on best available information. With regard to CT cost estimates, they relied independent -- upon independently developed CT cost studies from two leading engineering and construction firms.

As to the proposed increase in the Performance Adjustment Factor, the Companies strongly believe that such an increase would impose significant economic burdens on our customers and is not consistent with the intent or letter of PURPA. Leading up to this hearing, we have had a number of settlement discussions with the other parties in this proceeding. We were able to reach an agreement with the Public Staff on the CT costs and upon their proposed Option B, and you have that settlement agreement before you. We were also able to reach agreement with the Renewable Energy Group and NCSEA on the CT installed costs. And these are the two primary elements of this case.

First, the Public Staff, Duke Energy Carolinas, and Duke Energy Progress have agreed upon a CT cost to be used for calculating avoided capacity that is approximately 8 percent higher than Duke Energy Carolinas' filed CT cost and 14 percent higher than Duke Energy Progress' filed CT cost. In addition, Duke Energy Progress has agreed to adopt a new avoided cost rate schedule, Option B, that is similar to Duke Energy Carolinas' Option B. This will be in addition to Duke Energy Progress' already currently filed rate schedule option that is presented in this currently filed rate schedule.

Duke Energy Progress' new avoided cost rate schedule will use the same clarification of on-peak hours as Duke Energy Carolinas' Option B. This is a narrower definition of on-peak hours than Duke Energy Progress has used in its current avoided cost rate schedule. And the effect of these changes is that there are fewer on-peak hours, which means that a QF has to run fewer hours to receive a full measure of capacity credits. We think this will be a particular benefit for solar QFs because it will enable them to run a higher percentage of their peak hours. We also believe this is a much better approach than simply raising a Performance Adjustment Factor for solar and wind because it provides them an incentive to run during the hours when the Company's need for capacity is greatest.

Ultimately, Duke Energy Carolinas and Duke Energy Progress believe that the stipulation reached with the Public Staff and the later stipulation reached with REG and the North Carolina Sustainable Energy Association is a fair and reasonable resolution of the issues. We also believe that the Stipulation reached with the Public Staff is consistent with PURPA and is in the public interest. And we request the Commission to approve it in its entirety.

We also would like to move that stipulation into the record at this time.

COMMISSIONER BROWN-BLAND: All right. If there is no objection to receipt of the Stipulation between --

MS. FENTRESS: Duke Energy Carolinas, Duke Energy Progress, and the Public Staff.

COMMISSIONER BROWN-BLAND: If there's no objection to the receipt of that into evidence, it will be received and entered into evidence at this time.

(Whereupon, the Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress, and the Public Staff was admitted into evidence. The proprietary version was filed under seal.)

COMMISSIONER BROWN-BLAND: All right. Next? Who's next on the -- Ms. Kells.

MS. KELLS: Good morning, Chairman and Commissioners. Andrea Kells with Dominion. The purpose of this proceeding, as with every biennial proceeding, is to determine avoided cost rates and approve rate scales for contracts containing those rates for purchases of QFs. Under PURPA, rates for payments to QFs must not discriminate against QFs, but in no event can they exceed a utility's avoided costs, which FERC has defined as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the QF, such utility would generate or purchase from another source. The evidence given by Dominion --

COMMISSIONER BROWN-BLAND: Ms. Kells, could you make sure that the mic's sort of aimed at you?

MS. KELLS: Is that better?

COMMISSIONER BROWN-BLAND: That's good. Thank you.

MS. KELLS: The evidence presented by Dominion demonstrates that its calculation of avoided cost is accurate and consistent with the definition of avoided cost under FERC's rules and this Commission's orders implementing PURPA. With inputs and assumptions from its 2012 IRP, the Company calculated its avoided costs using the peaker method, which has long been recognized as an acceptable method for calculating avoided costs. The Company believes the evidence demonstrates that its avoided energy rates reflect its avoided energy costs and that its proposed capacity rates accurately reflect the Company's avoided capacity costs.

Dominion's evidence also shows that its proposed standard contracts for QF purchases are reasonable. Article VI of the Company's proposed standard contract details what happens if a regulatory body disallows the Company's recovery of QF payments from ratepayers. To be clear, it is not Dominion's wish that the disallowance clause be invoked. When the Company enters into a QF contract, which it is required by law to do, it should receive full ratepayer recovery of QF payments made under that contract.

By the same token, the QF should receive its full payments under the contract. But, while we believe the risk of a disallowance order is remote, we cannot ignore the fact that in two instances, once by this Commission and once in Virginia, the Company has been denied ratepayer recovery of a portion of its payments to QFs. In the event a disallowance does occur, given that the Company is legally compelled to enter into the QF contract in the first instance, there's no principal reason the QF should continue to receive its full payment at the expense of the Company and its ratepayers. Some parties have suggested the existence of the clause is a barrier to finance.

As stated, Dominion believes a disallowance to be remote risk, but it's a risk an investor can evaluate like every other risk associated with a QF contract. Just as an investor must evaluate the risk the QF could lose its QF status or have construction delays, they can evaluate this risk as well. In short, the risk of a disallowance is no different than any other risk an investor in a QF must evaluate.

Finally, not notwithstanding the disallowance clause, as discussed in Mr. Trexler's testimony, based on the QF contracts Dominion has signed and the number of CPCN's filed for projects in its service territory, there is a strong and active interest in QF development in the Company's service area. In calculating its avoided capacity costs, Dominion applied a PAF of 2.0 for run-of-river QFs and a 1.2 QF -- 1.2 PAF for all other QFs.

Some parties have asked the Commission to order the use of a PAF of 2.0 for solar QFs. The Company opposes this increase and believes a PAF of 2.0 does not accurately reflect solar QFs' ability to allow the Company to avoid the addition of additional peaking capacity. The Company recognizes that there is some overlap between the Company's peak times and solar QF output and is happy to support the Staff's Option B proposal.

Option B is designed to allow the QF to recover capacity credits over a fewer number of on-peak hours. This is beneficial to projects like solar with limited operating hours, but with output that is mostly during on-peak hours. With respect to the value of solar analysis discussed by NCSEA's witness, while -- Mr.

Rabago, while the Company believes that it may be a way to ascertain value of solar facilities to society generally, it is not a methodology of determining avoided costs as defined by PURPA.

As I explained, we have entered into a stipulation with the Public Staff and with REG regarding issues of CT costs, avoided capacity rates, and Option B. The Company requests that the Commission, once it is filed, accept the Stipulation as a reasonable settlement among Dominion and these parties of those issues. Thank you.

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

MR. YOUTH: Good afternoon. This is going to come as the understatement of the year, but avoided costs are complex. Settlements simplify things in some ways, but they also introduce complexities of their own. The order scheduling this hearing mentioned useful lives and economies of scale and there are five or ten other issues or concepts that were also contested. Some issues have been settled by some parties. Forget about all that for a minute.

I'm going to ask you to think in terms of, of all things, a spoonful of peanut butter and a piece of bread. Imagine that it's the 1930s and I, as a hypothetical landowner, put out an ad for some help to work my land. And the ad says, "Report for work in the morning and just for showing up, just for reporting and making yourself available, I will pay you a spoonful of peanut butter. Beyond that, if you work a whole day, I'll give you a whole piece of bread. If you work a half a day, I'll give you a half a piece of bread. If you work a sixth of a day, I'll give you a sixth of a piece of bread."

Imagine now that you made yourself available and you work a sixth of the day and then, maybe because of a sprained ankle, you cannot work anymore. You make your way to me for payment. I take out a piece of bread, and I spread a teaspoonful of peanut butter across it, cut out a sixth of it, and hand it to you and say, "Thank you very much." You're probably going to stop me and say, "Excuse me. You said I'd get a full spoonful of peanut butter. Not only did you use a small spoon, but you only gave me part of a spoonful."

You'd be right. Most of your spoonful is spread across the five-sixths of the bread that I'm keeping. It doesn't seem quite fair. In this case today, avoided energy payments are the bread. And nobody's really fighting about the size of the bread or how the bread is paid.

The spoonful of peanut butter is a different story. The peanut butter represents avoided capacity payments, and we disagreed about the spoonful of peanut butter in at least two ways. We still disagree in at least one way.

First, prior to the settlements we disagreed about what a spoonful is; is it a teaspoon or a tablespoon? It matters because the size of the spoon affects the amount of peanut butter you get paid. This disagreement about the size of the spoon involved costing a hypothetical combustion turbine, the spoon in this case.

Regardless, though, of how we resolved the spoon size question, whether it's a teaspoon or a tablespoon, we still have to resolve the fairness question about the peanut butter being spread over the whole piece of bread for those who cannot work a full day. This fairness question is where the Public Staff's Option B proposal and our solar 2.0 Performance Adjustment Factor proposal come in.

The Option B proposal says, basically, if you work a sixth of the day I'm going to spread the peanut butter over only half the piece of bread so that the sixth piece has more of the spoonful you're entitled to. That's one way to make sure you get paid more of the spoonful you're entitled to.

But there's a better way to address the fairness question in this proceeding. A 2.0 PAF for solar. For solar, a 2.0 PAF says, "I'm still going to spread the peanut butter over the whole piece of bread, but I'm going to spread it thicker on the sixth of a piece I'm paying you so that your sixth of a piece has even more of the spoonful you're entitled to. Short of a separate solar avoided cost rate, this is as fair as we can get in this proceeding.

Now, you may be thinking why don't I just pay you a plastic spoonful of peanut butter and give you whatever size piece of bread you've earned. Well, we don't do it that way here in North Carolina. The Commission long ago chose to make avoided capacity payments on a per kilowatt hour basis and not on a per kilowatt basis, which means here in North Carolina to pay off the peanut butter it has to be spread in some way, shape, or form on the bread.

Now, I understand the Public Staff has settled on the issue of how to spread the peanut butter. And there's no question the Utilities were right to settle from a strategic standpoint. I think the settlement has put the solar QFs in an interesting position. Continue to fight for your entitlement to full capacity payments and risk being perceived -- perceived as greedy and going after a windfall, or settle and seem more reasonable but at less than full avoided cost rates, which makes doing business as QFs more difficult.

It was a difficult decision, but we are going to proceed to hearing despite the Public Staff's settlement. And during the hearing and afterward in deliberations, I'm asking each of you Commissioners to keep two big-picture questions at the fore of your minds. First, what is the right size, the fair size, for the spoon, for the cost of a combustion turbine that is used to set avoided capacity payments? We think the spoon sizes we've settled on are fair.

Second, how do you make sure the independent worker, the small power producer, you in the peanut butter example, is getting paid as close to the full spoonful as possible when it is spread on the piece of bread? If you keep these questions in mind, I believe you'll see that the fairest way forward lies in affirming the settled CT costs and elevating the PAF for solar to

2.0. Thank you.

COMMISSIONER BROWN-BLAND: Ms. Mitchell.

MS. MITCHELL: I'll be brief. Good afternoon. I'm Charlotte Mitchell. I'm representing The Renewable Energy Group in this docket. My client is a mixed bag of renewable energy developers, owners, operators, installers, suppliers, interest groups. And when the proposed rates that the Utilities pay to qualifying facilities were filed almost a year ago in November, my clients noticed there was a precipitous drop in those rates.

As we've heard from Ms. Fentress, the rates are based on capacity costs, energy costs that are avoided by the Utilities. The energy costs are based in part on the price of natural gas. It's common knowledge that the price of natural gas has declined in recent years. Therefore, you're not -- you haven't heard discussion about the decline in the avoided energy component of these avoided cost rates. However, the rates also involve an avoided capacity component. And in this proceeding, not only did the avoided energy component drop; the avoided energy component of the rate declined, which again was expected. The avoided capacity component declined as well.

When my clients were made aware of this information, they decided it was time to get involved at the Utilities Commission. They intervened in this proceeding to make sure that the rates that had been proposed by the Utilities -- by the Utilities in this docket reflect nothing less than their full avoided costs.

My clients are reasonable people. They are not looking for a windfall. They are not looking for an enormous subsidy irrespective of what some parties in this docket might have you believe. They are looking for nothing less than the rates to which they're entitled under federal law.

My clients again are not unreasonable people. I think that's evidenced by the fact that they've settled with Dominion on the Option B offer that Dominion has put forward. As Ms. Fentress has indicated, this case is about the rates and how those rates are paid. As the Public Staff has indicated in its prefiled testimony, Option B is an alternative to an increased Performance Adjustment Factor. Option B changes the way that -- that avoided capacity rates are paid similar to the way the Performance Adjustment Factor does.

My clients are reasonable. They settled with

Dominion on an Option B. However, the rates that have been proposed by Duke and Progress simply aren't -- aren't sufficient for the Utilities to -- to encourage QF development in this state. Therefore, they have been unable to join in on the Option B that's put forth by Duke and Progress because it discourages QF development or does not encourage QF development.

I just want to emphasize one last time for the Commission. My clients are not looking for a windfall. They're simply asking that you allow them the rates to which they're entitled.

COMMISSIONER BROWN-BLAND: Thank you. Ms. Thompson?

MS. THOMPSON: Thank you, Madam Chair, Members of the Commission. I had reserved time on behalf of Southern Alliance for Clean Energy for a brief opening statement, but I'm not going to deliver one just given the posture of where we are in this docket.

I do want to let the Commission know that we appreciated the opportunity to review the draft of the settlement with -- between the Public Staff and DEC and DEP. Did not receive that in time to -- adequate time to review it prior to the hearing. We also very much appreciated the opportunity to confer with counsel for

REG and NCSEA. But at this time we're not taking a position one way or the other on the settlement -- on either of the settlements, and we'll just proceed with our questions in some very limited discreet areas. Thank you.

COMMISSIONER BROWN-BLAND: Thank you.

MS. RANKIN: (Shakes head negatively.)

COMMISSIONER BROWN-BLAND: The Public Staff declines an opening statement. All right. Now, since I had the cart in front of the horse -- but now I think we're ready. Ms. Fentress?

MS. FENTRESS: We would call Kendal Bowman to the stand, please.

KENDAL C. BOWMAN; Being first duly sworn,
testified as follows:

DIRECT EXAMINATION BY MS. FENTRESS:

Q **Ms. Bowman, can you please state your name and business address for the record?**

A My name is Kendal C. Bowman. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27602.

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

A I'm employed by Duke Energy. I am the Vice

President of Regulatory Affairs for North Carolina.

Q And today was there a Settlement Agreement filed on behalf of Duke Energy Carolinas and Duke Energy Progress?

A Yes.

Q And do you have a summary of a portion of that Settlement Agreement?

A I do.

Q And can you please read that summary into the record?

A Sure. (Summary read into the record.)

Duke Energy Progress, Inc.
Duke Energy Carolinas, LLC
Kendal C. Bowman's
Settlement Summary
NCUC Docket No. E-100, Sub 136

The purpose of my summary is to support the Stipulation Agreement entered into among Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP") and the Public Staff of the North Carolina Utilities Commission and to provide a brief overview of the settlement as it relates to DEC's adoption of a rate schedule comparable to Option B as described in the Stipulation. Pursuant to the Stipulation, DEP will file an additional avoided cost rate schedule that applies a definition of on-peak hours that is consistent with on-peak hours definition contained in DEC's Option B. This definition of on-peak hours is narrower than the definition DEP's proposed avoided cost rate schedule. As a result, the new DEP rate schedule will have higher avoided capacity rates than DEP's currently filed avoided cost rate schedule. The Utilities believe that DEP's adoption of the new rate schedule comparable to DEC's Option B is a reasonable compromise of the parties' respective positions in the context of the resolution of the issues by the Stipulation. As with the other components of the Stipulation, which will be discussed by Mr. Snider, the Utilities ask that the Commission approve the Stipulation in its entirety.

This concludes my summary.

Q Thank you. And did you also cause to be prefiled this document direct testimony consisting of 21 pages?

A I did.

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

A I do not.

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

A Yes.

MS. FENTRESS: I would request that the direct testimony be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed. The direct testimony of Kendal C. Bowman consisting of 21 pages filed August 13, 2013 will be received into evidence and is treated as if given orally from the witness stand.

MS. FENTRESS: Thank you.

(Whereupon, the public version of the prefiled direct testimony of Kendal C. Bowman was copied into the record as if given orally from the stand. The proprietary version of the testimony has been 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	)	DIRECT TESTIMONY OF
Biennial Determination of Avoided Cost	)	KENDAL C. BOWMAN ON
Rates for Electric Utility Purchases from	)	BEHALF OF DUKE ENERGY
Qualifying Facilities – 2012	)	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. DEP was previously named Carolina Power & Light, d/b/a Progress Energy Carolinas, Inc. The name change was effective April 29, 2013.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have a Bachelor of Science in Psychology from the University of Virginia and a Juris Doctor from Stetson University College of Law. My professional work experience began in 1997 when I began working as an attorney for

Florida Power Corporation in St. Petersburg, Florida. In 1999, I joined Carolina Power & Light Company as an associate general counsel. Shortly after I joined Carolina Power & Light Company, it merged with Florida Power Corporation and became Progress Energy. After the close of that merger, I was Progress Energy's attorney for the Federal Energy Regulatory Commission ("FERC") matters for all regulated utilities and our unregulated merchant generation operations. Upon Progress Energy's exit from the unregulated merchant generation business in the early 2000's, I led Progress Energy's legal federal regulatory affairs group and was responsible for FERC legal, policy and compliance matters for Progress Energy Carolinas and Progress Energy Florida. In 2010, I transitioned from FERC work to State Regulatory legal work for Progress Energy Carolinas in both North Carolina and South Carolina. Following the merger between Duke Energy and Progress Energy (the "Merger"), I became Deputy General Counsel supporting all legal state regulatory functions for North Carolina. In February of this year, I was named to my current role with Duke Energy.

Q. **WHAT ARE YOUR CURRENT RESPONSIBILITIES AS VICE PRESIDENT REGULATORY AFFAIRS AND POLICY FOR NORTH CAROLINA?**

A. In this role I am responsible for managing the Company's presence in all North Carolina regulatory matters and directing North Carolina energy policy for DEC and DEP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I provide a summary of the Utilities' positions in this proceeding. That summary includes a brief summary of our testimony, including the witnesses that will provide testimony on our behalf. My testimony also provides a brief narrative on history and requirements related to avoided cost rates, which helps explain the reasons for this docket. I also address some of the issues raised in the comments filed by other parties in this proceeding and our positions on those issues.

Q. PLEASE DESCRIBE BRIEFLY THE DIRECT TESTIMONY THAT THE UTILITIES ARE PRESENTING IN THIS CASE.

A. In addition to my testimony, the Utilities are presenting the direct testimony of Glen A. Snider, their Director of Carolinas Resource Planning and Analytics and Theodore P. Pintcke, Vice President and Senior Project Development Director, Black & Veatch Energy Group. Mr. Snider will explain how the Utilities developed the combustion turbine ("CT") cost estimates that they used to develop their avoided capacity rates and why those cost estimates are reasonable and appropriate. Mr. Snider will also explain why the Utilities believe that the proposed increase of the Performance Adjustment Factor ("PAF") for solar and wind qualifying facilities should be rejected. Mr. Pintcke will be providing his expert opinion as to the reasonable cost to build new CTs.

Q. CAN YOU PROVIDE THE COMMISSION WITH A HISTORICAL PERSPECTIVE ON THE REQUIREMENT THAT UTILITIES DEVELOP AVOIDED COST RATES?

A. Yes. In 1978, Congress enacted the Public Utility Regulatory Policy Act of 1978 ("PURPA"). PURPA was enacted largely in response to the 1970s energy crisis and, in part, to promote development of cogeneration and small power production facilities in the United States. It was believed that the development of cogeneration and small power production would help decrease the nation's dependence on foreign oil by capturing the steam that was a by-product of many industrial processes. These cogenerators and small power producers, collectively called "Qualifying Facilities" or "QFs," were granted new rights under PURPA to interconnect to the electrical grid and to sell their electrical output in the wholesale marketplace. To this end, Section 210(a) of PURPA directed the Federal Energy Regulatory Commission ("FERC") to develop rules to implement PURPA's requirements. One of those rules was to require the incumbent electric utility to offer to purchase electric energy produced by a QF. The rates should be both just and reasonable to the utility's electric consumers, in the public interest, and non-discriminatory to the QF. This mandate for just, reasonable, and non-discriminatory rates was enacted by Congress into a requirement that electric utilities offer to purchase the QF's output – either through a standard tariff rate or special contract (negotiated contract) – at the electric utility's "incremental cost of alternative electric energy," more generally referred to as the electric utility's "avoided cost." PURPA also provided that state Public Service Commissions, such as this Commission, are the appropriate bodies to determine avoided cost rates for the utilities over which a state's utilities commission has ratemaking authority.

Under PURPA, "incremental cost of alternative electric 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." PURPA also mandates that no rule implementing PURPA shall provide for a rate that exceeds the incremental cost to the electric utility of alternative electric energy. However, PURPA does allow State Public Service Commissions ("PSCs") to authorize rates lower than avoided cost (if determined sufficient by FERC to encourage QFs), while also providing parameters that electric utilities and state PSCs must comply with in determining what constitutes a just, reasonable, and non-discriminatory avoided costs rate.

Q. **HAS NORTH CAROLINA ADOPTED ANY STATE LAWS SIMILAR TO PURPA?**

A. Yes. In 1979, the North Carolina General Assembly adopted the requirements of PURPA for small power producers (hydroelectric generators no larger than 80 megawatts) in N.C. Gen. Stat. § 62-156, which provides that North Carolina's electric utilities shall offer rates to a QF small power producer ("SPP") that shall not exceed, over the term of the purchase power contract, the utilities' avoided costs. In determining the utilities' avoided costs, N.C.

Gen. Stat. § 62-156 provides that the Commission shall consider three factors over the term of the power contracts:

- The expected costs of the additional or existing generating capacity which could be displaced;
- The expected cost of fuel and other operating expenses of electric energy production that a utility would otherwise incur in generating or purchasing power from another source; and
- The expected security of the supply of fuel for the utilities' alternative power sources.

In addition, North Carolina's avoided cost statute provides that the "availability and reliability of power" shall also be considered in determining the rates to be paid by electric utilities for power purchased from a QF.

Q. HOW OFTEN DO THE UTILITIES HAVE TO FILE NEW AVOIDED COST RATES?

A. In compliance with PURPA and the North Carolina avoided cost statute, the Utilities file rates estimating their avoided cost, including both energy and capacity components, every two years for the Commission's approval. This proceeding represents the Commission's 2012 biennial avoided cost proceeding to determine each utility's avoided costs rates for purchases from QFs.

Q. IN REGARD TO THE COMMENTS FILED BY OTHER PARTIES TO THIS PROCEEDING, PLEASE DESCRIBE THE ISSUES THAT YOU ADDRESS IN THIS TESTIMONY.

A. First, I explain the rationale for the Utilities sharing information and collaborating in developing their respective avoided cost filings. At least one party has questioned the propriety of such collaboration. My testimony explains why that concern is unfounded and why the collaborative process undertaken by the Utilities is appropriate, expected by the Commission and serves the best interests of our customers.

Second, I address certain misconceptions regarding the intent and effect of the Utilities' collaboration. Some of the comments imply that the Utilities used the collaborative process to reduce their proposed avoided cost rates. My testimony demonstrates that DEC's and DEP's avoided cost rates are instead the result of the sharing best practices and the most current data to comply with PURPA's requirements.

Third, I discuss the proposal to increase the PAF for solar and wind QFs to 2.0. In particular, I explain why increasing the PAF would be detrimental to our customers and inconsistent with Senate Bill 3.

Fourth, I discuss an issue that is critically important to this proceeding, but is largely unaddressed by the other parties – the potential impact of the Commission's decisions in this Docket on the Utilities' customers.

Q. WHY DID THE UTILITIES WORK TOGETHER IN ENSURING THAT THEIR AVOIDED COST RATES ARE FAIR AND REASONABLE?

A. They did so to ensure that their avoided cost rates are based on the most reliable and accurate information available. It must be remembered and emphasized that every dollar paid to a QF is borne ultimately by the Utilities' customers. Thus, the Utilities have a duty to use the best and most current data available to them in determining their avoided costs. In the recently completed Merger, it was contemplated that the Utilities would adopt the best and most efficient practices for the benefit of their customers. This proceeding offers a unique opportunity to adopt the best practices. As the Commission is aware, DEC's and DEPs' ability to share information, compare projects and develop best practices was a significant benefit of the Merger for the Utilities' customers. In its Order approving the Merger, the Commission stated, "Additional potential benefits of the merger include economies of scale and scope and the leveraging of best practices." Specifically, the Commission cited the combination and assimilation of information technology systems and supply chain functions that would offset other cost increases required by new generation and compliance with new regulatory requirements. Such collaboration is particularly valuable for a process like the development of avoided cost rates. Avoided cost rates depend heavily on a number of projections and estimates, including the cost of constructing generation and long term gas prices. By pooling their data and sharing their individual analyses and projections, the Utilities were able to develop a more robust foundation for their avoided cost calculations. DEP and DEC have a responsibility to protect their customers from unnecessary rates and fuel costs increases resulting from compliance with PURPA and other regulations. In fact, Congress intended that ratepayers would not be harmed by the PURPA requirements by prohibiting rates that exceed the incremental cost of the electric utility of the alternative electric energy.

Q. **HOW DO YOU RESPOND TO THE SUGGESTION IN CERTAIN COMMENTS FILED IN THIS DOCKET THAT THE UTILITIES' DECISION TO SHARE DATA AND INFORMATION AND DEVELOP BEST PRACTICES FOR THE CALCULATION OF AVOIDED COSTS VIOLATED THE LETTER AND INTENT OF THEIR CODE OF CONDUCT?**

A. That suggestion is based on a misunderstanding of the terms of the Utilities' Code of Conduct, specifically Section III.A.1. of the Utilities' Code of Conduct entitled "Separation" and the Commission's policy behind it. That Section provides, in pertinent part, that

> DEC, PEC, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable. DEC, PEC, Duke Energy and each of the other Affiliates shall maintain separate books and records. Each of DEC and PEC's Nonpublic Utility Operations shall maintain separate records from those of DEC's and PEC's public utility operations to *ensure appropriate cost allocations and any arms-length transactions requirements.* [Emphasis added]

The Code of Conduct was adopted as part of the Commission's Order approving the Merger. The purpose of this provision is to assist the Public Staff and the Commission in monitoring and auditing transactions between the Utilities' Affiliates and Nonpublic Utility Operations. It is not meant to impair the Utilities' ability to provide additional benefits to their regulated customers. Thus, the requirement of "independent operation" does not preclude the sharing of information and best practices to improve each Utilities' operations for the benefit their respective customers. In essence, the Code of Conduct exists so that collaborative efforts can be encouraged while, at the same time, protecting the Utilities' ratepayers.

As stated previously, the Commission's Order approving the Merger contains several specific instances in which the sharing of information and the development of best practices were expected and in some cases required. These examples make clear that the Commission's expectation – consistent with the complete language of the Separation provision – was that, while each utility would operate independently and maintain its own separate native load obligations, each utility also would coordinate and share information in order to develop best practices for the benefit of its customers.

In summary, neither the Separation provision nor any other provision of the Code of Conduct precludes the sharing of information and best practices to improve each Utilities' operations for the benefit their respective customers. Indeed, to the extent practicable, the Utilities have an affirmative obligation to seek opportunities to share best practices, eliminate duplication, and achieve efficiencies across DEC's and DEP's utility operations for the benefit of ratepayers.

Q. **SOME OF THE COMMENTS FILED BY OTHER PARTIES IN THIS DOCKET IMPLY THAT THE REASON DEC AND DEP COLLABORATED IN DEVELOPING THEIR PROPOSED AVOIDED COST RATES WAS TO REDUCE THEIR PROPOSED AVOIDED COSTS. HOW DO YOU RESPOND TO SUCH COMMENTS?**

A. These assertions are not true. In fact, the collaborative process resulted in higher avoided cost rates for DEP. Again, as I explained earlier, the payments made by the Utilities are part of their costs of service, which are recovered from their customers. DEC and DEP collaborated in the development of their avoided costs in order to ensure their proposed avoided cost rates are as accurate as possible. The only goal of the collaboration between DEC and DEP was to share information and to compare practices in order to improve the process by which the Utilities calculated their avoided cost rates.

As several parties noted in their comments, the collaborative process did result in differences between the cost calculations employed in the Utilities' 2012 Integrated Resource Plan ("IRP") filings and their avoided cost filings. However, as explained in the Utilities' Reply Comments and Mr. Snider's testimony, the reason that those changes were not adopted in the Utilities' 2012 IRPs was that time constraints existed between the date of the Merger approval and the filing of DEC's and DEP's 2012 IRPs. Due to those timing issues, DEC's and DEP's 2012 IRPs were created separately, on a stand-alone basis, while the Utilities were able to work collaboratively on their avoided cost rate filings.

Had time permitted, the Utilities would also have collaborated in the development of their 2012 IRPs. Contrary to the suggestions made by other parties, and as discussed in more detail in the Utilities' Reply Comments and Mr. Snider's testimony, the Utilities' collaboration was not intended to decrease their avoided cost rates. In fact, many of the post-Merger decisions made by the Utilities increased their proposed avoided cost rates. For example, if DEP had developed its avoided capacity rates using the cost data in its 2012 IRP, the capacity component of DEP's avoided cost would have been significantly lower. Moreover, DEP adopted a higher long-term gas price forecast as a result of its collaboration with DEC.

In addition to the foregoing examples, the Utilities made other decisions that effectively increased their proposed rates. I can provide three examples here. First, the cost data used by the Utilities to calculate their avoided capacity rates is based on two independently-developed cost studies. Rather than relying on the lower of the two studies, the Utilities averaged the results of the studies. Second, neither DEC nor DEP chose to incorporate the effect of the Joint Dispatch Agreement ("JDA") in calculating their avoided cost rates despite the fact that the intent and effect of the JDA is to reduce the Utilities' cost of marginal energy. Cost of marginal energy is the basis for calculating avoided energy costs under the peaker methodology. Third, DEP calculated its avoided cost using its then allowed rate of return on common equity ("ROE") of 12.75% despite the fact that it had requested a significantly lower ROE of 11.25% in its pending rate case. In light of the imminence of an anticipated reduction in DEP's allowed rate of return, DEP would have been justified in departing from its practice of using its current rate of return for purposes of avoided cost calculations, particularly since the rates established in this docket will apply to long term fixed-rate contracts. Nevertheless, DEP chose to maintain its prior practice, which resulted in avoided cost rates being higher than they otherwise could have been. As these examples demonstrate, the Utilities did not engage in a concerted effort to push down avoided cost rates and no evidence to the contrary has been presented in this docket.

Q. DO THE UTILITIES HAVE CONCERNS REGARDING THE POTENTIAL CUSTOMER IMPACT OF THE POSITIONS TAKEN BY OTHER PARTIES IN THIS PROCEEDING?

A. Absolutely. Although this proceeding will establish the rates that the Utilities will pay for the output of QFs, in the final analysis, the cost of QF contracts are borne by the Utilities' customers. PURPA and its State equivalent are designed to eliminate ratepayer harm and not to provide a financial windfall to QFs. Generally, customers should be indifferent to whether a utility produces power from its own resources or purchases power from a QF because PURPA is designed to limit the payments to QFs to the purchasing utility's avoided cost. In this case, however, other parties have suggested that the Commission take steps to increase the rates to be paid to QFs to levels well above the

Utilities avoided costs. Such a decision could cost customers hundreds of million dollars more than they should rightfully have to pay.

Q. WHAT ARE THE PROPOSED INCREASES IN RATES PAID TO QFS TO WHICH YOU ARE REFERRING?

A. The two most significant proposed increases are: 1) an increase in the Utilities' avoided capacity rates; and 2) an increase in the Performance Adjustment Factor ("PAF") applied to the rates paid to solar and wind QFs.

Q. PLEASE BRIEFLY DESCRIBE THE UTILITIES' CONCERN REGARDING THE CUSTOMER IMPACT OF THE PROPOSED INCREASE IN THE UTILITIES' AVOIDED CAPACITY RATES.

A. The cornerstone of the argument for higher avoided capacity rates is that the CT costs used by the Utilities in this proceeding are lower than the costs used in earlier proceedings, particularly the Utilities' 2012 IRP filings. In essence, the Intervenors suggest that the use of data that is two years old or older is better than the use of current data. This argument ignores the fact that the costs to construct new CTs changes with the cost of labor, equipment, and financing. The data used in previous filings is different from that used in this proceeding, as is to be expected. Otherwise, there would be no reason to reset the Utilities' avoided cost rates every two years. The data used to support the Utilities' proposed avoided capacity rates in this case is based upon CT cost data that came from two current, independently-developed cost studies by leading engineering firms. As Mr. Snider explains in detail in his testimony, these CT costs are corroborated and supported by numerous third party sources.

In addition, as noted earlier, with regard to DEP's 2012 IRP, the entire premise of the argument is wrong because the CT cost data reflected in DEP's proposed avoided capacity rates is higher than the CT cost used in DEP's 2012 IRP. Importantly, the avoided cost rates approved by the Commission must be based upon the evidence of record. Statements that the proposed rates differ from previous rates do not provide an evidentiary basis for establishing avoided cost rates. Rather, the proponents of avoided capacity rates different from those proposed by the Utilities must be based upon actual data and calculations. The parties that propose higher avoided capacity rates in this case have not offered any such factual basis for their position. In summary, the Utilities have proposed avoided capacity rates based on CT costs that are supported by two separate cost studies conducted by leading industry experts and numerous industry sources. All of that data is current and all of it supports the conclusion that the Utilities used a reasonable and appropriate estimate of the cost of constructing a new CT in determining their avoided capacity costs. The Commission should accept the Utilities' proposed rates and certainly should not require higher rates that will cost consumers millions of dollars in additional electric costs. Additional reasons why this argument is without merit are contained in the Utilities' Reply Comments and the testimony of Mr. Snider.

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Q. PLEASE BRIEFLY DESCRIBE THE UTILITIES' CONCERN REGARDING THE CUSTOMER IMPACT OF THE PROPOSED INCREASE IN THE PAF FOR SOLAR AND WIND QFS.

A. In his testimony, Mr. Snider explains why the Utilities object to the proposed increase in the PAF for solar and wind QFs from an operational and system planning perspective. Here, I wish to make clear two additional points: 1) that increasing the PAF to 2.0 for solar and wind QFs is inconsistent with the purpose and intent of Senate Bill 3 and 2) that the Commission is being asked to impose a significant economic burden on the Utilities' customers without any legitimate policy reason to do so.

Q. PLEASE BRIEFLY EXPLAIN HOW THE PAF OPERATES.

The PAF is a multiplier applied to the avoided capacity rates paid to QFs to allow a QF to experience a reasonable amount of outage time without being penalized from the standpoint of the capacity payments it receives. The PAF was established because QFs only receive capacity payments for power that they deliver during on-peak hours. Because all generation is subject to outages, it is reasonable to assume that QFs, like other generation, will not run during 100% of on-peak hours. Thus, the PAF makes up for the fact that a QF might be unavailable during a peak period by increasing the capacity rate it is paid during the peak hours that it does operate. Currently, wind and solar QFs enjoy the benefit of a PAF of 1.2.

In this proceeding, the proponents of wind and solar generation are requesting the Commission increase the PAF for wind and solar QFs to 2.0. This same request was made and rejected in Docket No. E-100, Sub 117. An increase of the PAF from 1.2 to 2.0 is effectively a 67% increase in the avoided capacity payments that these QFs would receive. Nothing has changed since the Commission's decision in the Sub 117 docket and, therefore, this request should again be rejected.

Q. DO YOU BELIEVE THAT THE POLICIES UNDERLYING SENATE BILL 3 WARRANT AN INCREASE OF THE PAF FOR SOLAR AND WIND QFS?

A. No, in my view, it does not. The proponents of increasing the PAF for solar and wind QFs undoubtedly will cite Senate Bill 3 as policy justification for their position. However, when the particulars of that law are considered, it becomes clear that raising the PAF for solar and wind QFs would be inconsistent with the General Assembly's intent in passing Senate Bill 3.

Certainly, Senate Bill 3 evinces a public policy to encourage renewable generation in the State by establishing a renewable energy portfolio standard ("REPS") for the State's utilities. However, the General Assembly also made clear that there should be limits to the costs incurred pursuing that policy and nothing in Senate Bill 3 indicates that the General Assembly intended for its policy goals to be achieved by increasing avoided cost rates paid to certain renewable QFs. In fact, the provisions of Senate Bill 3 that limit the costs incurred by utilities, and ultimately recovered from their customers, to meet the requirements of Senate Bill 3 focus specifically on costs incurred ***in excess of the utilities' avoided costs.***

Senate Bill 3's use of the utilities' avoided cost as a reference point is particularly significant in the context of the present proceeding. The General Assembly provided a cost control framework under which utilities recover from their customers the "incremental" cost that the utilities incur in following the policy mandates of Senate Bill 3. In that regard, incremental cost was defined as the costs that the utilities paid to renewable resources in excess of the utilities' avoided costs. However, in N.C. Gen. Stat. § 62-133.8, the General Assembly placed a specific limit on the amount of such incremental cost that utilities could recover from their customers. It reinforced the importance of that limitation by including a provision that expressly stated that once a utility had incurred the maximum amount of incremental cost that could be recovered from customers, the utility would be conclusively deemed to have satisfied its obligations under Senate Bill 3, regardless of whether or not the utility had reached the target amount of new renewable resource capacity. Neither Senate Bill 3's policies supporting renewable energy development or the enactment of the REPS itself support redefining the "avoided cost" to subsidize particular resource types outside of the REPS compliance framework.

In sum, in passing Senate Bill 3, the General Assembly was clear in its intent to encourage the development of new renewable resources, but it was equally clear in establishing a limit on the amount to be spent in pursuit of that policy. Given that Senate Bill 3 uses utility avoided cost as a key component in its cost control framework, increasing the avoided capacity rates paid to solar and wind QFs by 67% is inconsistent with Senate Bill 3's customer protection measures. Accordingly, the Utilities do not believe that the REPS framework and policies enacted through Senate Bill 3 support the proposition that the Commission should increase avoided cost payments to solar and wind QFs by increasing the PAF for those facilities to 2.0.

Q. IS IT NECESSARY TO INCREASE THE PAF TO 2.0 FOR SOLAR AND WIND FACILITIES IN ORDER TO ENCOURAGE THE DEVELOPMENT OF SUCH INTERMITTENT RESOURCES?

A. No. In fact, the objective evidence demonstrates that the current policies in place to aid and encourage the development of such resources are more than sufficient. In the six months leading up to the filing of the Utilities' Joint Reply Comments in this docket, the Commission received over 450 applications for certificates of need and reports of proposed construction of new solar facilities. As of March 28, 2013, there were over 1,650 MWs of proposed solar generation facilities and approximately 200 MWs of proposed wind facilities in the Utilities' interconnection queues. Since that time, the amount of solar and wind generation in the Utilities' transmission queues has grown to approximately 2,300 MWs and 300 MWs, respectively. These figures demonstrate that the Utilities' current avoided cost rate structures – including the application of a 1.2 PAF for solar and wind QFs – is more than adequate to satisfy the State's policy in favor of encouraging the development of new solar and wind projects.

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Q. HOW WOULD AN INCREASE IN THE PAF FOR SOLAR AND WIND QFS TO 2.0 AFFECT THE UTILITIES' CUSTOMERS?

A. Quite simply, an increase in the PAF for solar and wind QFs will translate into higher rates paid to those QFs resulting in those higher costs being borne by the Utilities' customers. To provide a sense of the impact of increasing the PAF for solar and wind QFs to 2.0, the Utilities have calculated an estimate of the increased cost that would be incurred if the PAF for those facilities is increased in that fashion.

Specifically, for every 1,000 MWs of new solar QFs that execute 15-year fixed rate contracts, the Utilities estimate that REG's proposal to increase the applicable PAF to 2.0 would impose an incremental cost of over $150 million on consumers. This incremental $150 million is based on the avoided cost rates proposed by the Utilities. That figure is also conservative in that 1,000 MWs represents only a portion of the currently proposed solar projects and does not account for the additional projects that will be proposed in the future. In that regard, the Commission should consider that increasing the PAF for solar QFs to 2.0 will increase the influx of new solar projects as developers seek to take advantage of the inflated avoided capacity payments. Such an escalation in the number of new solar projects will exacerbate the burden on consumers. Additionally, if the Commission requires the Utilities to recalculate their avoided capacity rates using higher capacity costs, the impact of applying a 2.0 PAF to solar and wind QFs will also increase proportionally.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AS TO THE PROPOSAL TO INCREASE THE PAF FOR SOLAR AND WIND QFS TO 2.0.

A. One would expect a proposal to impose millions of dollars of incremental costs on consumers would be accompanied by an explanation of why such increased costs are necessary. However, there is no such explanation in the filings advocating for the increased PAF for solar and wind QFs. Indeed, there is no discussion of the increased cost to customers whatsoever.

In this case, there is no policy imperative that would warrant imposing this burden on consumers. Indeed, increasing the PAF for solar and wind QFs to 2.0 runs counter to the State's policy as set forth in Senate Bill 3. Moreover, as detailed in Mr. Snider's testimony, the proposed increase in the PAF is inconsistent with the operational realities of solar and wind QFs. Furthermore, there is no valid argument that the increased PAF is needed to encourage the development of these resources. With the current PAF of 1.2 in place, the number of proposed solar and wind projects has skyrocketed over the past twelve months and continues to grow. The Utilities, therefore, urge the Commission to reject the proposal to increase the PAF for solar and wind QFs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BY MS. FENTRESS:

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

A I do.

Q Can you please give it?

A The purpose of my direct testimony is to summarize the Utilities' positions in this proceeding. My testimony also provides a brief narrative on the history and requirements related to avoided cost rates, which helps explain the reasons for this docket. I also address some of the issues raised in the comments filed by other parties in this proceeding and our positions on those issues.

In 1978, Congress enacted the Public Utility Regulatory Policies Act or PURPA. Co-generators and small power producers, collectively called "Qualifying Facilities" or "QFs," were granted new rights under PURPA to interconnect to the electrical grid and to sell their electrical output in the wholesale marketplace. This mandate for just, reasonable, and nondiscriminatory rates was enacted by Congress into a requirement that electric utilities offer to purchase the QF's output -- either through a standard tariff rate or special contract (negotiated contract) -- at the electric utility's "incremental cost of alternative electric energy," more generally referred to as the electric utility's "avoided cost." North Carolina's avoided cost statute provides that the "availability and reliability of power" shall also be considered in determining the rates to be paid by electric utilities for power purchased from a QF. In compliance with PURPA and the North Carolina avoided cost statute, the Utilities file rates estimating their avoided cost, including both energy and capacity components, every two years for the Commission's approval.

DEC's and DEP's ability to share information, compare projects, and develop best practices was a significant benefit of the Duke Energy and Progress Energy merger for Utilities' customers. Avoided cost rates depend heavily on a number of projections and estimates, including the cost of constructing generation and long term gas prices. By pooling their data and sharing their individual analyses and projections, the Utilities were able to develop a more robust foundation for their avoided cost calculations. DEC and DEP collaborated in the development of their avoided costs to ensure their proposed avoided cost rates are as accurate as possible. The only goal of the collaboration between

DEC and DEP was to share information and to compare prices [sic] in order to improve the processes by which the Utilities calculated their avoided cost rates.

The Utilities have proposed avoided capacity rates based on combustion turbine, or "CT" costs that are supported by numerous industry sources, including two separate cost studies conducted by leading industry experts. All of that data is current and all of it supports the conclusions that the Utilities used a reasonable and appropriate estimate of the cost of constructing a new CT in determining their avoided capacity costs.

The Utilities object to the proposed increase in the Performance Adjustment Factor or "PAF" for solar and wind QFs from an operational and system planning perspective. The PAF is a multiplier added [sic] to the avoided capacity rates paid to QFs to allow a QF to experience a reasonable amount of outage time without being penalized from the standpoint of the capacity payments it receives. The PAF makes up for the fact that a QF might be unavailable during a peak period by increasing the capacity rate it is paid during the peak hours that it does not [sic] operate.

Currently, wind and solar QFs enjoy the benefit of a PAF of 1.2. An increase in the PAF for solar and wind QFs will translate into higher rates paid to those QFs, resulting in higher costs being borne by the Utilities' customers. There is no valid argument that the increased PAF is needed to encourage the development of these resources. With the current PAF of 1.2 in place, the number of proposed solar and wind projects has skyrocketed over the past twelve months and continues to grow.

This concludes my direct testimony summary.

MS. FENTRESS: The witness is available for cross-examination.

COMMISSIONER BROWN-BLAND: All right. I believe we'll begin with Mr. Youth.

CROSS EXAMINATION BY MR. YOUTH:

COMMISSIONER BROWN-BLAND: Mr. Youth, you've handed out a document here that has a premarked label on it as NCSEA Bowman Cross Exhibit Number 1. I will mark it -- have it so marked for identification.

MR. YOUTH: Thank you very much.

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

Q Good morning, Ms. Bowman. Good afternoon, Ms.

Bowman.

A Good afternoon.

Q You heard my peanut butter and bread opening statement, correct?

A I did. Where's the jelly?

Q I'd like to begin by asking you some questions about how, using my comparison, the peanut butter is spread on the bread; is that okay?

A That's fine.

Q If you will look at the cross exhibit, will you accept, subject to check, that pages 1 and 2 of the exhibit are an excerpt from a 2007 joint Duke and Progress proposed order in the 2006 biennial avoided cost proceeding?

A I will accept that it appears that way.

Q If you turn to page 2 of the exhibit at the arrow, Duke and Progress proposed the following sentence. "A wholesale power contract typically includes a capacity charge that is calculated on a per kilowatt basis and is payable regardless of the number of kilowatt hours the seller provides." Correct?

A That's what it says.

Q But North Carolina capacity charges under the standard rates are not paid on a per kilowatt basis, correct?

A That's my understanding.

Q Instead, if you go back to the next sentence in the joint Duke and Progress proposed order, and this is at the star in the left margin, "The standardized capacity rates for purchases from qualified facilities in North Carolina are calculated on a per kilowatt hour basis." Is that correct?

A That's what it says.

Q And so -- and here I'm looking at the next sentence in the joint Duke and Progress proposed order, "As a result, if rates were set at a level equal to a utility's avoided costs without a PAF, a QF would not receive the full capacity payment to which it is entitled unless it operated 100 percent of the on-peak hours throughout the year." Did I read that correctly?

A You did.

Q While we're on that sentence, I just want to highlight that Duke and Progress, as always, chose their words carefully. The sentence says, "The full capacity payment to which it," i.e. the QF, "is entitled." It uses the word "entitled," correct?

A Yes.

Q And Duke and Progress agreed on that language for their joint proposed order, correct?

A I -- I am assuming so.

Q Subject to check?

A Subject to check.

Q I will ask you to now turn to page 3 of the cross exhibit. Will you accept, subject to check, that pages 3 through 5 of the exhibit are an excerpt from the Commission's 2007 order in the 2006 biennial avoided cost proceeding?

A Subject to check.

Q You agree subject to check?

A Yes. Subject to check, I agree.

Q On page 4 of the cross exhibit, at the arrow, if you will review that language? The Commission adopted Duke and Progress' proposed language, correct? Subject to check.

A Subject to check. If you'll give me a moment to please read? Okay. Agreed subject to check.

Q And if you'll turn to the next page, page 5, at the arrow, the Commission was actually asked in this proceeding, the 2006 proceeding, to make capacity payments on a kilowatt basis instead of a kilowatt hour basis. But it stated, "The Commission is not persuaded by CUCA's -- CUCA's argument that the Commission should order the Utilities to pay for QF capacity on a kilowatt basis. The system currently in place has worked well for years and continues to be appropriate." Correct?

A Correct.

Q So as I put it in my opening argument, for North Carolina standard avoided cost rates we don't pay out peanut butter by the spoonful; we spread it on the bread, something like that. Would you agree with that?

A Yes.

Q And so if you'll turn back now to page 4 of the cross exhibit at the star in the margin. The Commission stated, "As a result, if the rates were set at a level equal to the Utilities' avoided costs without a PAF, a QF would not receive the full capacity payment to which it is entitled unless it operated 100 percent of the on-peak hours throughout the year." That's what the Commission said, correct?

A Yes, that's what it says here.

Q In other words, because the Utilities pay QFs on a per kilowatt hour basis here in North Carolina, we've got a situation where a QF that operates intermittently can be shorted on the capacity payment to which it is entitled. That's what the Commission was getting at, correct?

A I can't speak to what the Commission's intent was behind this.

Q **Put another way, a PAF, whether it is 1.2 or 2.0 or something else, is designed to fix the shorted capacity payment issue and help make sure QFs get the full capacity payments to which they are entitled, correct?**

A Could you rephrase that?

Q **I can repeat it.**

A Please repeat it.

Q **A PF -- excuse me, a PAF, whether it is 1.2 or 2.0 or something else, is designed to fix the shorted capacity payment issue and help make sure QFs get the full capacity payments to which they are entitled.**

A I think I would agree that the Performance Adjustment Factor of 1.2 was established for intermittent resources that were not available to get -- if they're not available 100 percent of the time to get some kind of capacity payment.

Q **I'm going to ask it one more time in a different way --**

A Okay.

Q **-- taking the numbers out. A PAF is designed to fix the shorted capacity payment issue and help make**

sure QFs get the full capacity payments to which they are entitled; is that correct?

A Under PURPA, a QF is entitled to the full avoided cost rates.

Q And so the PAF is designed to ensure that they get their full avoided capacity rates.

A I think the PAF was a policy decision that the Commission implemented. I believe they started it in 1996. They increased it in the hydro facilities. It started with the run-of-the-river hydro, realizing that it was an intermittent resource, a finite resource. It was North Carolina public policy to promote it, and they wanted to put it on equal footing with the Utilities' own hydro facilities. Realizing that it could not be available 100 percent of the time, the Commission instituted a Performance Adjustment Factor of 1.2 that gave them capacity as if they were available 83 percent of the time.

Q I'm going to try one more time. Because in North Carolina we pay -- the Utilities make avoided capacity payments on a per kilowatt hour basis, a QF will not receive the full capacity payment to which it is entitled -- unless it operated 100 percent of the on-peak hours throughout the year, it will not receive the full

capacity payment to which it is entitled in the absence of a PAF; is that correct?

A If the rates were set at a level equal to the Utilities' avoided costs without the PAF, a QF would not receive the full capacity payment to which it is entitled unless it operated 100 percent of the on-peak hours throughout the year. That is what it says in this order.

Q Thank you. Now, to get a better understanding of the PAF and what it does and doesn't do, I'm going to ask you to go back further in time with me. We were just looking at documents from around 2006, 2007. I'll ask you to turn to page 6 of the cross exhibit. Will you accept, subject to check, that pages 6 and 7 of the exhibit are an excerpt from CP&L's, Progress', reply comments in the 1996 biennial cost proceeding?

A Yes, subject to check.

Q On page 7 of the cross exhibit, at the arrow, CP&L, Progress, wrote, "CP&L and the Public Staff have agreed that for hydroelectric generation facilities with no storage capability and no other type of -- and no other type of generation, a performance factor of 2.0 will be used. It was agreed that due to the North Carolina General Assembly's desire to encourage hydro generation as expressed in North Carolina General Statute

62-156, the environmental benefits of hydro generation and these type facilities' inability to control the availability of their fuel, it is appropriate to adjust the performance factor in this manner." Is that what the order says?

A Yes.

Q Excuse me. Is that what the reply comments state?

A That is what the reply comments say on page 5.

Q I've read your testimony, and I understand we may disagree about the extent to which the General Assembly desires to encourage solar generation. But I think we can both agree that through laws like the REPS with its solar carve out, the renewable energy tax credit for which solar is eligible, and the laws that limit the extent to which local governments can restrict residential rooftop solar, the General Assembly has certainly expressed a desire to encourage solar generation, correct?

A That is correct, but I would also add in Senate Bill 3 and in the REPS proceeding, the North Carolina General Assembly wants to encourage solar and renewable generation; but they also caveated it not at any cost as well. They did instill cost caps in Senate Bill 3 so there was a concern that they did not want the ratepayers in North Carolina to have to pay an exorbitant amount for the renewables as well.

MR. YOUTH: Commissioner Brown -- Brown-Bland, I would ask that all of the response after the "yes" be stricken as nonresponsive.

WITNESS: I --

MR. YOUTH: I think Ms. Bowman will have a chance to elaborate on any answers she has given on redirect.

MS. FENTRESS: Madam Chair, Ms. Bowman is entitled to explain her answer. That has been the practice and tradition of this Commission, and I would object to Mr. Youth's motion to strike.

COMMISSIONER BROWN-BLAND: The motion is overruled.

BY MR. YOUTH:

Q I'm going to ask you to jump just for a second to the Commission's 2007 avoided cost order on page 17 of the cross exhibit at the star in the margin. In that order, the Commission wrote, "Since the hearing in this case, however, the General Assembly has enacted S.B. 3," if you'd move down a bit, "which creates and REPS for the state's utilities and establishes strong state policy

support for renewable energy resources." Is that correct?

A Correct.

Q And Duke itself, in its recently filed 2013 IRP, acknowledges a state desire to encourage solar development. If you would turn to pages 8 and 9 of the cross exhibit, specifically page 9 at the arrow, Duke wrote in its filed 2013 IRP, "The Company continues to see an increasing amount of alternative energy resources in the transmission and distribution queues. These resources are mostly solar resources due to the combination of federal and state subsidies to encourage solar development." So Duke concedes the state desires to encourage solar development, even if it disagrees as to the extent. Correct?

A Yes.

Q And just as CP&L recognized back in 1997 that hydrogeneration had environmental benefits, you'd agree that solar also has environmental benefits. We may disagree on the quantification of the benefits, but Duke agrees solar has environmental benefits, correct?

A Absolutely.

Q And just as CP&L recognized back in 1997 that hydrogeneration facilities don't control the rain and river flow that is their fuel, you'd agree that solar facilities don't control the sun that is their fuel, correct?

A That's correct.

Q Now, I'm not sure how careful any of us have been in our filings or testimony on this next point and so I want to be as clear as possible. A higher PAF doesn't affect a utility's avoided costs; rather, it simply changes the manner in which avoided costs are paid, correct?

A It is an additional payment on top of the avoided costs. It is an adder to the capacity component.

Q Maybe I'm not being clear. If you'll turn back to page 7 of the cross exhibit? About halfway down the paragraph that I have arrowed -- and again, we are now in 1997. When the run-of-river hydro PAF was raised to 2.0, CP&L or Progress filed these comments stating, "The --

A I'm sorry. Which page are you on?

Q I'm on page 7 of the cross exhibit.

A The comments on the performance factors?

Q Correct.

A Okay.

Q And I am four or five, depending on how you count --

A Uh-huh.

Q -- four lines up from the bottom. "The use of a different performance factor for hydroelectric generators does not affect CP&L's avoided costs; rather, it simply changes the manner in which avoided costs are paid." Is that the way CP&L put it back in 1997?

A Well, that's the way it's written. But the way it's written also can imply what I just said. It is an adder to the capacity portion of the avoided cost payment.

Q Okay. But it does not affect CP&L's avoided costs.

A No, because the avoided costs are set by the Utilities Commission based on the methodology of what is a CT cost. And then you bring in the energy component. And then once you establish that CT cost, you do a multiplier. You add the Performance Adjustment Factor onto it. And you can follow up with Mr. Snider, as well, if you want.

Q Are you saying that the adder exceeds avoided costs or it's within avoided costs?

A I say it's an adder that exceeds the avoided costs.

Q I'll ask you now to turn to page 10 of the

cross exhibit. Will you accept, subject to check, that pages 10 through 12 of the cross exhibit are an excerpt from CP&L's March 3rd proposed order in the 1996 biennial avoided cost proceeding?

A Yes, I'll accept subject to check.

Q If you'll turn to page 12 of the cross exhibit, at the arrow, CP&L, Progress, proposed the Commission adopt the following language: "Importantly, the use of a different performance factor for hydroelectric generators does not affect CP&L's avoided costs. Rather, it simply changes the manner in which avoided costs are paid. Thus, the use of such a performance factor does not result in CP&L paying these hydro QFs more than CP&L's avoided costs." Did I read that correctly?

A Yes.

Q So from the reply comments we looked at a minute ago to this proposed order, CP&L added the sentence that says, "The use of such a performance factor, i.e. a 2.0 instead of a 1.2, does not result in CP&L paying these hydro QFs more than CP&L's avoided costs." It added that sentence, correct?

A Correct. And that may have been true in 1997, but I don't have all of the documents and numbers behind this to fully understand.

Q And the Public Staff ratified this statement, didn't it?

A I don't know. Could you show me how it ratified it?

Q I would love to. Will you accept, subject to check, that pages 13 through 15 of the cross exhibit is the March 4 brief of the Public Staff filed in the 1996 biennial avoided costs proceeding?

A Subject to check, I'll accept.

Q If you turn to page 14 of the cross exhibit, at the arrow, the Public Staff wrote, "The Public Staff has reviewed CP&L's proposed order filed on March 3, 1997. To the extent that it addresses the issues resolved between the parties, the Public Staff believes the proposed order accurately represents the agreements between the Public Staff and CP&L. On those findings and conclusions, then, the Public Staff recommends that the Commission adopt CP&L's language." Did I read that correctly?

A Yes.

Q Before I leave this page, I'll ask you to shift your attention up to the star in the margin. And very quickly, with regard to whether the Commission has authority to approve a higher Performance Adjustment

Factor, the Public Staff wrote, "Furthermore, the use of a higher performance factor is not preempted as argued by Duke. It is not an adjustment to avoided costs. Instead, it is a change in methodology by which a QF is paid." Did I read that correctly?

A Yes.

Q So I think we've established that the Public Staff supported CP&L's March 3rd proposed order. So I'll ask you to turn back to page 11 of the cross exhibit, back to CP&L, Progress', proposed order at the arrow. With the Public Staff's support, CP&L, Progress, wrote: "The Public Staff asserts the use of a performance factor of 1.2 is still appropriate and that the capacity credits paid hydroelectric generating facilities should reflect an even higher performance factor due to their inability to control their fuel supply and the fact that the Commission allows Duke Power to recover all of the capacity costs of its hydro units, notwithstanding the fact that their capacity factors are substantially below the level a QF hydro would have to operate to recover the full capacity credit." Did I read that correctly?

A Yes.

Q Okay. To keep with this line of thinking for a moment, I'd like next to jump forward in time. Will you agree, subject to check, that pages 16 through 18 of the cross exhibit are an excerpt from the Commission order in the 2006 biennial avoided costs proceeding?

A Yes, subject to check.

Q I'll ask you to turn to page 17 at the arrow. And this is 17 of the cross exhibit, sorry.

A I've got it. Thanks.

Q Discussing its order -- you recall this was back in 2006, 2007, the Commission states, "As the Public Staff witnesses point 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 recover the full cost of these facilities. With respect to solar and wind QFs, however, this comparison has no relevance because the state's utilities have no solar or wind facilities in rate base. On the other hand, the Commission agrees that solar and wind QFs, like run-of-river facilities, have no control over their energy source. This is a legitimate argument for treating them in the same manner as run-of-river hydro QFs." Did I read that correctly?

A You did read that correctly.

Q Back in 2006, 2007, neither Duke nor Progress had any solar in rate base, correct?

A That is correct. They had no solar and no wind.

Q But today, Duke at least does have solar in rate base, correct?

A It is a combination of some in rate base and some recovered through our energy efficiency DSM. And it was a pilot program approved by this Commission in 2009. It's a 10-megawatt facility, $50 million project. It's mostly on rooftops; rooftops of residences, schools, and businesses.

Q I'll ask you to turn to the next page in the cross exhibit, page 19 of the cross exhibit. This is a NCSEA data request asking for identification of any Duke or Progress owned solar facilities. And in response, Duke and Progress provided an Excel spreadsheet, correct?

A Yes.

MR. YOUTH: Now, Commissioner Brown-Bland, the response was not marked confidential, but out of an abundance of caution before I hand it up I'd like to run it by Duke's attorneys.

COMMISSIONER BROWN-BLAND: Please do so.

(Pause.)

MR. YOUTH: Commissioner Brown-Bland, I've been told that the information on this exhibit is confidential. And so I will hand it up to the Commissioners, to the court reporter, to the Duke attorneys, to the witness. And I believe all of the attorneys up at the table have confidentiality agreements with Duke and Progress. But I would ask that this be marked as NCSEA Confidential Bowman Cross Exhibit 2.

COMMISSIONER BROWN-BLAND: All right. The exhibit handed out by Mr. Youth that has been premarked -- has been premarked NCSEA Bowman Cross-Examination Exhibit 2, but it shall be identified as NCSEA Confidential Cross-Examination Exhibit Bowman 2. And it would be the one with microscopic --

(Whereupon, NCSEA Bowman Confidential Cross-Examination Exhibit No. 2 was marked for identification.)

MR. YOUTH: Commissioner Brown-Bland, I think despite the fact that the exhibit is confidential that I can ask my questions in such a way that I do not elicit any confidential information.

COMMISSIONER BROWN-BLAND: All right.

BY MR. YOUTH:

Q I apologize for the small print. But Ms. Bowman, subject to check, there are roughly 25 Duke owned solar facilities identified on Confidential Cross Exhibit

2; is that correct?

A Subject to check, yes.

Q And then if you could go down to the bottom row, it says, "2012 capacity factor, if available." If you go across, Duke hasn't listed capacity factors for each of the facilities, but it does list some numbers. And I'm not sure whether those are really confidential. Would you give me your best guess as to the rough average of the numbers that are written on the exhibit?

A If I can see, I think it's a capacity factor roughly averaging about 18 percent.

Q And now I think we can leave this exhibit.

A Well, I want to note a lot of these properties are rooftops, which is not a comparable comparison to a QF that is entitled to avoided cost payment. A lot of these would be comparable to a rooftop solar that's under the net metering program in North Carolina.

Q Are all of the solar facilities listed here Duke owned?

A Subject to check. I don't know the -- I'm assuming they are, but subject to check.

Q And are they all rooftop?

A The majority, from what I see I believe they are. But it's subject to check. I don't know if they all are. There -- there may be one or two that are not, but I don't know for certain.

Q And are at least -- is at least one of those facilities listed in Duke's North Carolina rate base?

A Yes, again, and remember the project was split between -- it was a pilot project, partial between rate base and energy efficiency and DSM.

Q So again, just to make sure I'm understanding, Duke does have solar in rate base?

A We do have a portion of it, yes.

Q If you now flip back to Cross Exhibit 1 and look at page 20, this page contains Duke's and Progress' response to an NCSEA data request. It indicates that Duke and Progress ascribe a 17.4 percent capacity factor to non-utility solar PV in their 2013 IRP's; is that correct?

A Yes.

Q And that capacity factor is applicable to solar QFs in general, correct?

A I would ask that question to Glen Snider.

Q The number you see, though, 17.4, is very close to what you surmised the average of Duke's -- Duke-owned solar capacity factor was, correct?

A Correct.

Q So there's really no difference between the capacity factor of a Duke-owned solar facility and a QF solar facility; they're all generally in the 17 to 18 percent range, correct?

A Correct. They're generally available in producing power about 17 percent of the time.

Q Duke gets full cost recovery for its solar, though, just as it gets full cost recovery for its hydro, correct?

A Well, what do you mean by full cost? Because we do not get an energy payment. We do not get fuel. As a QF gets a fuel component, a solar facility that is a QF gets an energy component as well. I believe you mentioned that in your opening statement. That's the bread. They get about 70 percent. They get the fuel component. Our solar facilities or our hydro facilities do not get that. It's -- you're comparing apples and oranges.

How a utility recovers its cost is a different mechanism than a QF. A QF is entitled the avoided cost of a utility. A utility recovers via rate cases, assuming perfect ratemaking. There's regulatory lag, and we recover our cost of the capacity but not the energy, not the fuel piece. So it's not apples to apples. Both are fair, but they are different.

Q **So Duke recovers its capacity costs related to solar through ratemaking, base rate cases?**

A Hypothetically, if we were to -- if DEC, the regulated utility, were to put a large-scale solar facility in, we would try to recover the capacity of that through a rate case. But we would not be entitled to that energy fuel component that a QF gets. It's two different types of recovery mechanisms. They're different, but they are fair.

Q **But as to the capacity cost for the Duke-owned solar facility --**

MS. FENTRESS: Objection. I believe Mr. Youth has asked this question.

MR. YOUTH: I don't believe I have. I haven't even finished my question.

COMMISSIONER BROWN-BLAND: Let's hear your question, Mr. Youth.

BY MR. YOUTH:

Q **As to a Duke-owned solar facility, through its rate case Duke would recover 100 percent of that capacity cost; is that correct?**

A Assuming perfect ratemaking we would recover our capacity cost.

Q Duke-owned solar has to operate at a 17 percent capacity factor or so for Duke to get that full capacity cost recovery in a perfect ratemaking rule. On the other hand, a solar QF in Duke territory has to operate at a currently impossible 83 percent capacity factor to recover its full capacity payment, correct?

A But the QF is already getting an avoided cost, which includes capacity and energy.

Q So you started your sentence with "but." Does that mean it is correct but --

A Yes.

Q Let me ask this also at this point. Does Duke have any definitive plans to add more solar to rate base?

A If it is a least cost resource, yes. Duke is a proponent of supporting solar. It can be a benefit to the system when added in a measured approach. We are obligated by law to provide least cost resource mix. Reliability is of utmost importance for us to serve our customers. So if it fits in the least cost then, yes, we could put it in our resource mix.

Q If you look on page 22 of Cross Exhibit 1, subject to check, at the arrow Duke says in its recently filed 2013 IRP that, "The Company's plan currently projects that by the end of the planning horizon the

Company will have met over 700 megawatts of peak demand through solar resources, the equivalent of one large natural gas facility." Is Duke planning for some of those additional solar resources to be Duke-owned?

A I don't have that knowledge.

Q Do you have knowledge that Duke is at least exploring putting more solar in rate base?

A We are exploring solar. We are studying solar and storage capability and studying wind. We encourage the development of renewable resources. We are in conjunction with UNC to do a three-year coastal wind project. We are studying storage and solar, the intermittency and how our system reacts to that intermittency at the McAlpine project. So yes, we are -- we are looking at ways to improve the grid so we are investing in research and development looking at these assets. Absolutely.

Q How about Progress? Does Progress have any definitive plans to add any solar to its rate base?

A I would say my answer would be the same for both DEC and DEP.

Q And if Duke and Progress do own more solar in the future, isn't it true that Duke and Progress will recover the capacity costs of their solar fleets from

ratepayers, notwithstanding the fact that the solar facilities' individual capacity factors will be substantially below 83 percent?

A If we can justify that solar is least cost, we will put it in and try to recover it in rate base.

Q But a solar QF would still have to operate at an 83 percent capacity factor to recover the full capacity credit it is entitled to; isn't that correct?

A I believe I've already answered this question multiple times before. I said -- yes.

Q Okay. Now, I'd like to go back in time once more back to the Commission's 1997 order where it approved the 2.0 PAF for hydro. Will you accept, subject to check, that pages 23 through 24 of the cross exhibit is an excerpt from the Commission order in the 1996 biennial avoided costs proceeding?

A Pages what?

Q 23 and 24 of the cross exhibit.

A Yes. And I will note this was before Senate Bill 3.

Q If you turn to page 24 at the arrow, the Commission stated in its 1997 order: "Some parties comment that a higher Performance Adjustment Factor for certain QFs is discriminatory or in excess of avoided costs decreed by PURPA." And then skipping down to the star in the margin, the order goes on: "Use of a higher performance factor for these hydro facilities does not exceed avoided costs. It simply changes the method by which avoided costs are paid. It allows these QFs to operate less in order to receive the full capacity payments to which they are entitled, and this seems appropriate and reasonable considering the limitations on their control of their generation." Did I read that correctly?

A You did read that correctly. And I will say this is again about hydro facilities. And hydro facilities are unique. They are different than solar. There's a finite amount of places in the state of North Carolina where you can install a hydro facility. There are unlimited rooftops that you can put solar on so there was a special purpose in creating this 2.0 for hydro facilities. It was encouraged by North Carolina policy. North Carolina policy also encourages solar development as well. That's why they created Senate Bill 3. And we have seen a prolific amount of solar in this state.

MR. YOUTH: Commissioner Brown-Bland, I would ask again that after the responsive portion of Ms. Bowman's response that it be stricken after the initial two sentences.

MS. FENTRESS: DEC and DEP would object to the motion to strike. Ms. Bowman's answer was relevant and pertinent and in response to Mr. Youth's question.

COMMISSIONER BROWN-BLAND: I'm going to deny the motion to strike and ask Ms. Bowman to be circumspect in the answers.

WITNESS: Yes, ma'am.

BY MR. YOUTH:

Q I'd like to flash forward from the 1996 biennial proceeding now to the 2002 biennial proceeding. If you'll turn to page 25, will you accept, subject to check, that pages 25 through 26 of the cross exhibit are an excerpt from Progress' June 2003 proposed order in the 2002 biennial avoided costs proceeding?

A I will agree.

Q I'll ask you to turn to page 26 at the arrow. Progress proposed, "Importantly, the use of a different performance factor for hydroelectric generators does not affect PEC's avoided costs. Rather, it simply changes the manner in which avoided costs are paid. Thus, the use of such a performance factor does not result in PEC paying these hydro QFs more than PEC's avoided costs." So on this point, even six years after the 1996 proceeding, Progress' position remained the same as it was in the 1996 proceeding, correct?

A Yes, it is the exact same language used previously.

Q So the use of an appropriate -- an appropriate performance factor, whether 1.2 or 2.0 or something else, does not result in a utility paying more than its avoided costs; rather, it simply helps ensure the QF receives the capacity payment to which it is entitled. Correct?

A Again, I go back to what I previously said on this point.

Q Okay. I'd like to flash forward again to the 2006 biennial proceeding. But before I do, I want to clarify something if I can. Duke is currently working on a solar cost benefit study called the solar integration study, correct?

A I don't know what you're talking about. Solar integration study?

Q Forget for now what I called it.

A Okay.

Q Is Duke -- are Duke and Progress working on a solar cost benefit study?

A We are working on a study, and we have hired several external consultants. And I'm trying to find the list of them. It is an impact study, and witness Snider can go into more detail. It's looking at the impact of the installation of solar on our system, the physical operational impacts. What does, you know, a certain level of penetration of solar in our system do to, number one, the distribution, the transmission, starts and stops of your generation assets? What does it do to back flow feeds? Do you need additional capacitor banks?

We are looking at the impacts. We have hired Pacific Northwest National Labs, Clean Power Research, and Alstom to help us with that. I wouldn't say it's, you know, a -- a study that -- it's not a VOS, I think, as one of the witness -- witnesses described.

Q So you're saying -- I want to make sure I'm very clear on this. Duke is not, where possible, quantifying potential benefits and costs of solar generation.

A I'd say that is a second phase. We have to do a phase one. We need to understand the impacts to our system. I believe if you're going to truly assess the value of solar, you have to look at both the benefits and the impacts. And so we are doing a phase one. We are looking at the impacts of what intermittent resources do to our grid.

COMMISSIONER BROWN-BLAND: Mr. Youth, would this be a place where we could take a break?

MR. YOUTH: It would be.

COMMISSIONER BROWN-BLAND: We're going to stand in recess until 2:55.

(WHEREUPON, THERE WAS A SHORT RECESS.)

COMMISSIONER BROWN-BLAND: We'll come back on the record. And Mr. Youth, we'll pick up with your cross examination.

MR. YOUTH: Thank you, Chairman -- Commissioner -- Chairwoman Brown-Bland.

Q I think the last question and answer established that Duke and Progress as a second phase of a current study will be looking at the costs and benefits of solar; is that correct?

A Yes, that's correct.

Q Does this second phase of the study represent the first time Duke will really be quantifying the costs and benefits of solar on its North Carolina systems?

A I believe that's correct, subject to check.

Q So again, and subject to check, are there any already completed studies quantifying the benefits of solar for North Carolina that Duke is keep classified?

A Not that I'm aware of, no.

Q So Duke didn't have any study results quantifying the benefits of solar back in 2007, correct?
A Not to my knowledge.
Q Will you accept, subject to check, that pages 27 and 28 of the cross exhibit are an excerpt from the rebuttal testimony of Duke witness Steve Smith in the 2006 biennial avoided cost proceeding?
A Yes, subject to check.
Q I'll ask you to turn to page 28 at the arrow. Mr. Smith testified, "In addition, the Company believes the benefits of photovoltaic power contribution during peak hours is already recognized and appropriately priced in the Company's Option B rates contained in Schedule PP." Correct?
A Yes, you read that correctly.
Q My question is if Duke hadn't quantified the benefits of solar back in 2007, how could Mr. Smith have known back in 2007 that the benefits of solar were already recognized and appropriately priced in the Company's Option B rates?
MS. FENTRESS: Objection. I believe he is asking Ms. Bowman about what Mr. Smith knew.
COMMISSIONER BROWN-BLAND: I'll sustain the objection.

BY MR. YOUTH:

Q We've already touched on the fact that Duke's 20,000 [sic] IRP -- this is on page 22 of the cross exhibit -- says, quote, that by the end of the planning horizon the Company will have met over 700 megawatts of peak demand through solar resources the equivalent of one large natural gas facility, end quote. So solar will avoid a large Duke gas facility, correct?

A I believe it's the megawatts equivalent to it. The best person to ask would be Mr. Snider, who actually manages and directs our IRPs.

Q And if you turn to page 29 of the cross exhibit, will you accept subject to check that pages 29 through 30 are an excerpt from Duke's recently approved 2012 IRP?

A Yes, subject to check.

Q If you flip to page 30 of the cross exhibit at the arrow, does the IRP state, "The shift of the Duke Energy Carolinas first capacity need from 2015 to 2016 is primarily due to" and then it lists several things including "an increase in project capacity and energy purchases from qualifying facilities pursuant to the requirements of the Public Utility Regulatory Policy Act of 1978, PURPA." Does it say that?

A Yes.

Q **And would you agree subject to check that a lot of that QF capacity mentioned is solar?**

A Subject to check, yes.

Q **So based on Duke's 2012 Commission-approved IRP, QF solar helped defer Duke's next capacity need, correct?**

A Again, I think the more appropriate witness to address that is Mr. Snider.

MR. YOUTH: Thank you. No more questions.

COMMISSIONER BROWN-BLAND: Thank you. Ms. Mitchell, would you like to go next?

MS. MITCHELL: Yes, ma'am.

COMMISSIONER BROWN-BLAND: All right.

CROSS EXAMINATION BY MS. MITCHELL:

Q **Ms. Bowman, I just have a few questions on PAF, Performance Adjustment Factor. And there may be some duplication with some of the things that Mr. Youth was asking, but I'm going to do my best to cut out those questions that we've already covered. Just for the -- in the interest of clarity, when I use the word "Duke" I mean Duke Energy Carolinas; and when I use the word "Progress" I mean Progress Energy Carolinas just to be clear.**

A Okay. Thank you.

Q So Ms. Bowman, we've established that the Commission has traditionally approved the use of the Performance Adjustment Factor in calculating avoided cost rates; is that correct?

A That is correct in previous proceedings, yes.

Q And hasn't the Commission stated that the PAF takes into account the fact that a generating facility cannot be in operation at all times?

A Certain QF facilities cannot be in operation at all times.

Q Okay. Thank you. And I know we covered this with Mr. Youth --

COMMISSIONER BROWN-BLAND: Ms. Mitchell?

MS. MITCHELL: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Would you make sure that mic is on and near you?

MS. MITCHELL: Okay. Is it working now?

COMMISSIONER BROWN-BLAND: You might need to switch mics with her, please. Although we could hear Mr. Youth, but --

MS. MITCHELL: Okay. Is this better?

BY MS. MITCHELL:

Q So like I was saying, we've covered this with

Mr. Youth, but I'm going to ask you a quick question. Hasn't the Commission recognized that if rates are set at a level equal to the utility's avoided cost without the PAF, a QF would not receive the full capacity payment to which it's entitled unless it operated at 100 percent of the on-peak hours throughout the year? Just to refresh your recollection, I'll refer you back to --

A Yeah.

Q -- Mr. Youth's -- the NCSEA Bowman Cross Exhibit 1. And if you turn to page 4?

A I'll agree that's what it says, yes.

Q Okay. Thank you. And is it correct that based on longstanding tradition of the Commission, certain QFs enjoy a 1.2 PAF?

A That's correct.

Q And doesn't a 1.2 PAF reflect the Commission's judgment that if a QF is available 83 percent of the time it's operating in a reasonable manner and should be allowed to recover a utility's full avoided capacity cost?

A Yes. That's operating 83 percent of the time at the peak, I believe, but yes. Yes.

Q Okay. Thank you. Ms. Bowman, does Duke own solar generating facilities?

A Yes.

Q **Does Progress own solar generating facilities?**

A No.

Q **Does Progress have plans to own solar generating facilities?**

A Not that I'm aware of at this time.

Q **Do Duke's solar facilities operate during 83 percent of the utility's on-peak hours?**

A I don't know that I know specifically the answer to that. I think we established that they had roughly a 17 to 18 percent capacity factor.

Q **Okay. Thank you. This may be a question for Mr. Snider, but I'm going to try with you. Do you know whether Progress' base load capacity factor is less than 83 percent?**

A I would ask Mr. Snider that. I don't have the IRP in front of me.

Q **And should I ask the same question with respect to Duke --**

A Yes.

Q **-- of Mr. Snider?**

A Yes.

Q **Okay.**

A He would have both Duke and Progress.

Q Okay. I'll try one more question. Is Progress' system capacity factor less than 83 percent?

A I would ask that to Mr. Snider.

Q Okay. Is it correct that since 1996 the Commission has allowed the use of a 2.0 PAF for certain hydroelectric facilities?

A For hydro facilities, that's correct.

Q Okay. And hasn't the Commission justified this increased PAF for those certain hydro facilities on the basis that a 2.0 PAF allows them to receive the full capacity payments to which they are entitled while operating under the constraints created by their stream flows?

A I believe that's correct.

Q Okay. One last question. Hasn't the Commission noted in the context of a 2.0 PAF that the use of that 2.0 PAF doesn't result in rates that exceed avoided costs, but rather it simply changes the method by which avoided costs are paid to QFs?

A I think my same answer to Mr. Youth on that question was it is an adder to the capacity. So you go through -- you're setting your avoided costs; you set your CT cost, you set the energy cost, and then you do a multiplier. The PAF is a multiplier to that capacity.

Q Okay. So is that a yes that the Commission has noted that it simply changes the way -- the method by which avoided costs are paid?

A Well, I think we agreed to what the language was in the previous orders that Mr. Youth walked us through.

MS. MITCHELL: Okay. No further questions.

COMMISSIONER BROWN-BLAND: All right. Ms. Ottenweller?

MR. OTTENWELLER: Yes, ma'am.

COMMISSIONER BROWN-BLAND: I think that mic does not operate. You'll have to share that one. Sorry.

CROSS EXAMINATION BY MS. OTTENWELLER:

Q Good afternoon, Ms. Bowman. I just have a few questions for you related to line losses. If a retail store sited a multi megawatt solar installation on its roof and entered into a QF contract with a utility, the power produced by that installation would likely be consumed within the nearby distribution network, correct?

A That's correct.

Q So even for a store with several megawatts of solar on its rooftop, most of the power is being consumed at or near the distributed generation source?

A That is my understanding.

Q Okay. Neither utility, DEC or DEP, includes distribution line losses in its calculation of avoided cost, correct?

A I don't know if I'm the best person to answer that. I believe Mr. Snider could provide you --

MS. FENTRESS: I believe Mr. Snider can respond to those questions.

BY MS. OTTENWELLER:

Q Okay. And should I direct all line loss questions to Mr. Snider or --

A You should. He's the engineer, not me.

MS. OTTENWELLER: Okay. No further questions. Thank you.

COMMISSIONER BROWN-BLAND: All right. Does the Public Staff have any questions?

MR. DODGE: Yes. My name is Tim Dodge. I'm appearing on behalf of the Public Staff. I was out of the room during appearance of counsel earlier. My colleague Gisele Rankin has had to leave the room for the afternoon, but I'll be helping out as well. Per our stipulation with the Utilities, we've agreed to waive cross examination of witnesses. I do have one clarifying question based on Ms. Bowman's examination so far today. Would it be acceptable to ask that question at this time?

COMMISSIONER BROWN-BLAND: If there is no objection. Yes.

CROSS EXAMINATION BY MR. DODGE:

Q Good afternoon, Ms. Bowman.

A Good afternoon.

Q Earlier, Mr. Youth was asking you some questions about DEC's DSG -- DG solar program. Do you recall those questions?

A Yes, I do.

Q And you responded that the costs of that program were recovered through a combination of programs including the DSM EE Rider. Do you remember making that statement?

A Yes, I do. And I have been informed I was incorrect.

Q Okay.

A That it's not the DSM EE; it's the REPS Rider.

Q Correct.

MR. DODGE: Thanks. No further questions.

COMMISSIONER BROWN-BLAND: All right. Redirect?

MS. FENTRESS: Thank you.

REDIRECT EXAMINATION BY MS. FENTRESS:

Q Ms. Bowman, we have walked backwards and

forwards in history today so I'm going to take you back to the very beginning and ask you if you agree that PURPA requires electric utilities to offer to purchase electric energy produced by a QF at the electric utlity's incremental cost of alternative energy. Do you agree with that statement?

A I do.

Q And would you agree that the incremental cost of alternative energy is the cost to the electric utility of the electric energy which, but for the purpose of the QF, the utility would generate itself or purchase from another source?

A That's correct.

Q And while PURPA perhaps was not designed to produce cost savings to consumers, would you agree it is also not designed to impose costs that are in excess of the utility's incremental cost of electric energy on consumers?

A I would agree with that.

Q And I think you have also spent a lot of time reading Commission orders into the record, and we've talked a lot about that. Do you agree with every word you have read into the record? Would you agree that at this time some of the findings and conclusions of those

past orders remain pertinent or applicable?

A I would not agree. I think times have changed.

Q And even though times have changed, Progress and Duke -- I'm sorry, DEP and DEC are not challenging the 1.2 Performance Adjustment Factor for solar; is that correct?

A That's correct. We're not challenging that in this proceeding.

Q And in fact, we have adopted an Option B which we believe is a reasonable alternative to the Commission imposing a 1 -- a 2.0 Performance Adjustment Factor on -- on wind and solar; is that correct?

A That's correct. We believe that Option B is a rational approach. It has a nexus to PURPA. It encourages the QFs to run at times when they're most needed. As opposed to Performance Adjustment Factor, which is just arbitrarily handing out money, Option B incents the QFs to operate at a point in time when our system actually needs that power.

I believe if you look at witness Ellis -- Public Staff witness Ellis' testimony, there are things that a solar facility can do to tilt their solar panels to receive peak power at certain points in the day when the Progress and Duke systems see their peak as well. So we believe that Option B gives an incentive; additional payments, but it gives an incentive. We believe that's a much better approach than raising a Performance Adjustment Factor.

Q So there are additional payments made to the QF under Option B?

A Yes. There is an increase to the QF under Option B than what we originally proposed.

Q And there's also been a lot of discussion about well, the utility has solar in its rate base and the utility has hydro in this rate base -- in its rate bases, shouldn't we treat them the same? Is hydro -- how would you characterize its availability as a resource? Is it a fairly limited resource?

A It is a very limited resource.

Q Particularly as compared to solar, would you agree?

A Yes, as compared to solar.

Q And so there might have been policy reasons at that time for promoting a hydro renewable development when that 2.0 was adopted by the Commission; would you agree?

A I would agree.

Q So again, talking about the fact that we have

hydro in our rate base and solar in the Company's rate base, I wanted to talk to you a little bit about the differences between the two. Do QFs when -- get paid avoided cost rates for energy?

A Yes. QFs get energy component.

Q And do solar and wind QFs have significant energy costs?

A No, their fuel is free. That's one of the benefits. They get power when the sun shines and when the wind blows.

Q And I believe Mr. Youth asked you about the solar facilities that the Company may have in its rate base. If the utility installs a solar or wind facility, is the utility recovering any fuel cost associated with that -- with the operation of that facility?

A We are not earning on that fuel cost, no.

Q And why is that?

A Because it's not part of our cost of capital.

Q And our rates and our rate recovery is structured differently from the rate recovery of a QF; isn't that correct?

A Yes, it's two different structures.

Q Mr. Youth asked you also about the need for a QF to run at 83 percent of the time to get a full capacity payment assuming a 1.2 Performance Adjustment Factor. Do you recall that?

A Yes, I recall that line of questioning.

Q And he also asked you about solar being able to run about 17 or 18 percent of the time; is that -- is that correct?

A Yes.

Q So I'm going to try to talk about math so bear with me. A QF only has to run on peak hours to get capacity; is that correct?

A That is correct.

Q And isn't it true that under DEC's and DEP's Option B they use peak hours of 1,860?

A Yes. The Option B shortens the peak hour in which the QF has to run to get payments.

Q And just for a reference, there are 8,760 hours in a year?

A Correct.

Q Okay. Subject to check, isn't 1,860 about 20 percent of the hours of the year?

A That's correct.

Q And if a QF has a 1.2 Performance Adjustment Factor, isn't it true that it only has to run 83 percent of the peak hours?

A Yes. It would only have to run 83 percent about 20 percent of the time.

Q And so if a QF with a 1.2 Performance Adjustment Factor under Option B only has to run 83 percent of 20 percent of the hours in the year -- is that correct?

A That's correct.

Q Is 83 percent of 20 percent about 17 percent, subject to check?

A It is about 17 percent, which is the same capacity factor that the same Duke installed solar facilities are.

Q Ms. Bowman, you've practiced law here for a regulated energy company since 1999; is that correct?

A That's correct.

Q And in your opinion has solar QF production and development been encouraged or discouraged in the last few years?

A It's been highly encouraged. With Senate Bill 3 and with the tax incentives that North Carolina passed we have seen a tremendous increase in solar in North Carolina.

Q And you would agree that solar provides benefits to North Carolinians?

A Absolutely.

Q And you would agree that those tax incentives in Senate Bill 3 provide incentives for -- to develop solar?

A They provide incentives, and it's worked very well.

Q But does PURPA require the Commission to consider or factor in those tax incentives for Senate Bill 3 type regulation when it calculates the incremental cost of alternative electric energy under PURPA?

A No, it does not.

Q Thank you. Now, on page 26 of the cross exhibit, if you want to turn to that, and I'll just direct your attention down to the last line of the main paragraph on that page, if you'd like, or the second to last line.

A Okay.

Q And I just -- would you agree that that line says that the Commission -- that there is a compromise agreement between PEC and the Public Staff to strike the appropriate balance?

A Yes.

MR. YOUTH: I'm going to raise an objection at this point, that is -- and my objection is -- well, the sentence says the Commission found. I'd like to make sure this is understood to be part of a proposed order so it's actually Progress Energy that is writing that; it is not a Commission order.

Q I'm fine with that clarification, but there -- it is referring to a compromise agreement. Would you agree, Ms. Bowman?

A Yes, I would agree it refers to a compromise agreement.

Q Now, turning to -- you were -- let's see, page 17 of the cross exhibit. You probably got there quicker than I did. Are you there, Ms. Bowman?

A I am here.

Q You would agree that in that -- on that page, as Mr. Youth I believe pointed out, that the Commission does discuss some parallels between hydro and solar?

A Yes, they do.

Q And so moving to page 18 in the first paragraph --

A Yes.

Q -- I'll ask you to go down to about the middle of the paragraph, and it's a sentence that begins, "Once."

A Yes, I'm there.

Q And would you agree, subject to check, that that is referring to -- that this paragraph has to do with Senate Bill 3?

A Yes.

Q Okay. And would you agree that that -- that that order says once the rules are in place and the REPS, meaning the Renewable Energy Portfolio Standard, part of Senate Bill 3, is in operation, the market for renewable energy in North Carolina is likely to change dramatically? So any -- that any issues relating to the Performance Adjustment Factor may be presented in an entirely new context in the future. Do you agree that it says that?

A Yes, I do agree.

Q And because I'm not asking you just to read into the record what the order says but whether you actually agree with it, do you agree that once the rules were in place that the market for renewable energy in North Carolina changed dramatically?

A Yes, it -- it absolutely did change dramatically.

Q And do you believe that in addition to Senate Bill 3 and that in addition to the tax incentives that QFs require additional incentives through PURPA to

encourage development?

A I do not believe that solar needs an additional Performance Adjustment Factor in North Carolina to encourage development.

Q And since we're talking about Performance Adjustment Factor and past orders and positions that the parties may or may not have taken, are you aware of any positions taken by NCSEA on the appropriateness of the Performance Adjustment Factor in previous filings?

A Yes. I am aware of one, and it was in the Commission's 2008 biennial review of avoided costs, in which they actually picked up that very question that they were referencing that the -- in the order that we were just speaking of referencing that once Senate Bill 3 rules were in place that it would change and we would need to relook at the Performance Adjustment Factor.

Q And do you agree with that position as stated by NCUC?

A Well, the position in the 2008 order --

Q Do you want to share it with us, the --

A Could I read from that? It's the Commission order if I could share it. It was in Docket E-100, Sub 117 in 2008. "In this proceeding, NCSEA's comments recited some of the history and stated that, in departure from its previous policy stance, it no longer supports establishing higher PAFs for renewable generation facilities other than run-of-the-river hydros. NCSEA concluded that other policy tools are available to encourage renewable QFs and that those tools would be vastly more effective and transparent for long-term market development than assigning a higher Performance Adjustment Factor. Examples listed by NCSEA of such tools are technology price caps for cost recovery, specific renewable energy certificates, RECS; pricing through alternative compliance payments, redesign utility rate structures to encourage private investments in renewable distributed generation, residential REC buy-back programs. NCSEA concluded by requesting the Commission to pursue other, more effective and transparent policy mechanisms for developing a robust renewable QF market in North Carolina.

"Based upon the foregoing, the Commission concludes that a PAF of 2.0 should be utilized by PEC and DEC in respect to avoided cost calculations for hydro facilities with no storage capability and no other type of generation and that a PAF of 1.2 should be used for all other QFs. With respect to NCSEA's request that the Commission pursue other policy mechanisms to encourage renewable QFs, the Commission concludes that the consideration of such policy mechanisms are more appropriately considered in a docket other than a biennial avoided cost proceeding."

Q **And for the record, could you read the date and the caption from the beginning of what you just read from? I'm sorry.**

A The hearing was heard on January 27, 2009, at 9:00 a.m. I'm looking for the date the order was issued. The order was issued on the 13th day of May 2009.

Q **And do you agree with the observations by NCSEA that you have just read into the record?**

A Yes, I do. I believe we have come up with other ways to encourage solar renewables in the state of North Carolina.

Q **Do you believe that Option B is a reasonable alternative?**

A I believe that Option B is the best alternative. It gives them a higher payment, but it's rational; it incents them to behave in a way that actually helps the system out.

MS. FENTRESS: I have nothing further.

COMMISSIONER BROWN-BLAND: All right. At this point, does anyone have any questions that you were saving that were of a confidential nature in cross-examination for this witness on confidential material?

(No response.)

COMMISSIONER BROWN-BLAND: I take it that's no, so is there questions from the Commission of a non-confidential nature? Commissioner Rabon.

EXAMINATION BY COMMISSIONER RABON:

Q Good afternoon.

A Good afternoon.

Q On page 19 of your direct testimony, you discuss -- it starts about line 9 -- you discuss the amount of solar and wind in the Utilities' interconnection queues to demonstrate that the current structure is adequate to support the State's policy encouraging the development of new solar and wind projects?

A Yes.

Q In your experience, how much of what is put in the interconnection queue actually comes online?

A That question would be better answered by witness Snider.

Q Okay. Okay, very well. You put Mr. Snider on notice.

COMMISSIONER BROWN-BLAND: Ms. Bowman, you

earlier mentioned in response to -- I believe the question is now asked by your counsel as well as Mr. Youth that there's no energy payments to utilities for hydro and solar in Duke's rate base, and you mentioned that in the context of comparing apples to apples. Do you remember that?

A Yes, I do.

Q But isn't it true we don't calculate capacity and energy components in that way, that we use the peaker methodology; and as a part of that methodology, the energy component is not specific to the type of unit? Isn't that correct?

A That is correct. The energy component is based on fuel forecasts more than cost.

Q All right. And the capacity -- it's the capacity piece that is based on --

A CT costs.

Q -- CT costs?

A Yes.

Q All right. Also, a minute ago I believe in response to your counsel's question we were looking at page 18 of the Cross -- Cross Examination Exhibit 1, and there was the reference to once the rules were in place there was likely to be dramatic change. And you agreed

that there had been dramatic change. Could you expound upon what you mean by there had been -- there has been dramatic change?

A Well, as Commissioner Rabon pointed out, I believe on my direct testimony on page 19 I describe the number of requests we've had in the queue. We now have over 2300 megawatts in the queue, and we've actually -- we are buying from over 200 megawatts installed and operating today since that point in time. So for solar I do believe that is a dramatic increase. And if -- if you read trade rags, depending upon the various day of the week, North Carolina ranks up in the top five in terms of solar development across the country.

Q **And one other question. A minute ago when you were first describing Option B, you talked about the merits of Option B and you used a phrase about just arbitrary -- not arbitrarily giving out money. You didn't intend by that testimony to indicate that the avoided cost decisions made by this Commission resulted in arbitrary handing out of money?**

A No, I did not.

COMMISSIONER BROWN-BLAND: All right. Thank you. Any other questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: Are there questions on Commission's questions?

(No response.)

COMMISSIONER BROWN-BLAND: Mr. Youth?

MR. YOUTH: Is this the time only for questions on Commission questions or also for questions on --

COMMISSIONER BROWN-BLAND: Just questions on Commission questions. All right.

MS. MITCHELL: I have one question.

CROSS EXAMINATION BY MS. MITCHELL:

Q Ms. Bowman, I think you used the term "trade rag" in your response. Can you just explain? I don't -- I don't understand what that means. Would you just explain what you mean?

A It's like "Power Daily," "Energy Daily," S&L reports, media that tracks the energy industry.

Q Okay. Thank you.

COMMISSIONER BROWN-BLAND: At this time, the Commission has at least one question that is of a confidential nature so I'll ask those in the hearing room who have not signed on to the appropriate NDA, non-disclosure agreements, to please leave at this time. We'll have someone notify you when you may return.

And I'll ask the Companies, or those whose

information is at risk, to make sure that the room is properly populated for this segment. All right. The room has been cleared. Counsel for Duke, is everyone in the room acceptable to you?

MS. FENTRESS: Yes, they are.

COMMISSIONER BROWN-BLAND: No ambiguity intended in the question. I'm going to call on Commissioner Beatty.

(Because of the proprietary nature of the testimony contained on pages 169 to 171, it was filed under seal.)

(Testimony on the open record resumed.)

COMMISSIONER BROWN-BLAND: Okay. I believe we have exhausted our round of questions for this witness. Is that correct? Any requests?

MS. FENTRESS: Enter her testimony into the record.

COMMISSIONER BROWN-BLAND: I believe we've accepted it. But in case we haven't, that testimony will be accepted into the record. Any exhibits, Mr. Youth?

MR. YOUTH: May I have a moment? Commissioner Brown-Bland, do the parties have an opportunity to ask questions on the questions that were asked by Ms. Bowman's counsel? Is there another round?

MS. FENTRESS: We do not traditionally have recross. We do not have recross.

COMMISSIONER BROWN-BLAND: No, we do not. Commission's questions are the last round. All right. Exhibits? Do you want to move your exhibits in?

MR. YOUTH: Yes, please. I would ask that the two NCSEA Bowman cross exhibits be moved in, the non-confidential and the confidential ones.

COMMISSIONER BROWN-BLAND: That motion, without objection, will be allowed.

(Whereupon, NCSEA Bowman Cross-

Examination Exhibit 1 and NCSEA
Bowman Confidential Cross-Examination
Exhibit 2 were admitted into
evidence.)

COMMISSIONER BROWN-BLAND: I believe the witness may step down.

(Witness is excused.)

MR. SOMERS: Thank you, Madam Chair. If we could, we'll call our next witness, Mr. Glen Snider. As Mr. Snider is coming forward to be sworn, make note that we are going to hand out two summaries, one of his direct testimony; the other is a statement in support of the settlement.

The statement supporting the settlement does have a confidential number in it. What I would propose to do is ask Mr. Snider to read that without reading the actual number. Mr. Allen is handing out copies of that statement which contain it to the Commission and the parties that have signed confidentiality agreements. That's -- that's how I would propose to do that without clearing the room just to read one single number if that's acceptable to the Commission.

COMMISSIONER BROWN-BLAND: That's acceptable, and I take it that we determined we would not bring this witness forward as a part of a panel?

MR. SOMERS: That's -- that's correct. We'll put him on individually. And we'll put on his direct at this time, and rebuttal will come back later.

COMMISSIONER BROWN-BLAND: And before we swear him in, I would like to state on the record that earlier the Commission admitted the comments that have been filed in this case, and I admitted them as evidence because the parties had agreed to have them so admitted. But the Commission also recognizes that they are not sworn, sworn to. They are not sworn testimony, and they will be given the weight that they are due in light of that fact.

And now, is there a Bible there for you, Mr. Snider?

GLEN A. SNIDER; Being first duly sworn,
testified as follows:

DIRECT EXAMINATION BY MR. SOMERS:

Q Thank you. Would you please state your name for the record?

A Glen Snider.

Q And Mr. Snider, what do you do for a living?

A I am director of Carolinas IRP planning and analytics.

Q And by whom are you employed?

A Duke Energy Carolinas. And I also serve in that role for Duke Energy Progress as well.

Q And what is your business address?

A 400 South Tryon, Charlotte, North Carolina 28202.

Q And Mr. Snider, did you cause to be prefiled direct testimony in this case of some 55 pages?

A I did.

Q And do you have any corrections or additions to your prefiled testimony?

A I do not.

Q So if I were to ask you the same questions as are contained in the prefiled direct testimony, would your answers be the same?

A They would.

MR. SOMERS: Madam Chair, I would ask that Mr. Snider's direct testimony be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: It will be so admitted.

(Whereupon, the public version of the prefiled direct testimony of Glen A. Snider was copied into the record as if given orally from the stand. The proprietary 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	))))	DIRECT 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 as Director of Carolinas Resource Planning and Analytics.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DEC AND DEP.

A. I am responsible for the supervision of the Integrated Resource Plans ("IRPs") for both Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") also referred to as the Utilities in my testimony. In addition to the production of the IRPs, I have responsibility for overseeing the analytic functions related to resource planning. Examples of such analytic functions include unit retirement analysis, developing the analytical support for certificate of public convenience and necessity ("CPCN") filings for new generation, and production of analysis required to support the Utilities' avoided cost calculations that are used in the biennial avoided cost rate proceedings for purposes of determining filings.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. My educational background includes a bachelor of science in mathematics and a bachelor of science in economics from Illinois State University. With respect to professional experience, I have been in the industry for over twenty years. I started as an associate analyst with the Illinois Department of Energy and Natural Resources, responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst job with Florida Power Corporation and for the past twelve years have held various management positions within the industry. These positions have included managing the risk analytics group for Progress Ventures, the wholesale transaction structuring group for ArcLight Energy Marketing and, immediately prior to the merger of Duke Energy Corporation and Progress Energy ("Duke-Progress Merger" or "Merger") Manager of Resource Planning for Progress Energy Carolinas.

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

A. Not at this time.

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

A. The purpose of my testimony is to support DEC's and DEP's (collectively, the "Utilities" or "Companies") proposed avoided cost rates, as filed by the Utilities in this proceeding on November 1, 2012. First, my testimony will provide an overview of the avoided cost rates proposed by DEC and DEP. Second, I will explain the process used to develop our proposed avoided cost rates, including the cooperative efforts between DEC and DEP following the approval of the Merger. Third, I will describe the combustion turbine ("CT") construction costs used by the Utilities in developing the capacity component of their avoided cost rates and explain the basis for the CT costs used. I will also explain the differences between the CT costs used in this proceeding by the Utilities and the CT costs used by the Utilities in previous proceedings, and explain why those differences are reasonable and justified. Fourth, I will address certain specific concerns raised by other parties to this proceeding regarding the CT costs underlying the Utilities' avoided cost rates, including: 1) the amount of contingency assumed in the CT costs; and 2) the assumption of a 35-year useful life for CTs. Finally, I explain the Utilities' opposition to the Renewable Energy Group's ("REG") proposal that the Commission increase the Performance Adjustment Factor ("PAF") to be applied to the rates paid to solar and wind Qualifying Facilities ("QFs") from 1.2 to 2.0.

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

A. My testimony will show the following:

- The collaborative approach taken by DEC and DEP after the merger of Duke Energy and Progress Energy resulted in a sharing of data and processes that improved the avoided cost rate development process for both Utilities.
- The Utilities' proposed avoided capacity rates are based on CT cost estimates that are reasonable, well-developed and verified by multiple sources.
  - Contrary to the suggestions of other parties to this proceeding, the post-Merger cooperation between the Utilities resulted in several decisions that actually increased the Utilities' proposed avoided cost rates. Examples include using the higher of the two Utilities' natural gas forecasts, use of conservative capital carrying costs, not including the lower marginal avoided energy costs that would be associated with Joint Dispatch and the use of an average of the CT cost estimates from two different cost studies rather than the lower of the two cost estimates.
  - The CT cost estimates used by DEP in its avoided cost rates are actually higher than the CT cost estimates that were used in DEP's 2012 IRP.

  - o The CT cost estimates used by DEC in its avoided cost rates are significantly lower than the CT cost estimates that were used in DEC's 2012 IRP. However, this difference is almost entirely attributable to DEC's elimination of a spreadsheet error and excess contingency from the CT cost estimate used in its 2012 IRP.

- Increasing the Performance Adjustment Factor ("PAF") for solar and wind QFs from 1.2 to 2.0 would impose a significant economic burden on the Utilities' customers. Further, there is no policy imperative that warrants such an increase in the PAF for those facilities.

I. METHODOLOGY USED TO DETERMINE AVOIDED COST RATES

Q. HOW ARE THE UTILITIES' AVOIDED COSTS CALCULATED?

A. Avoided cost rates are the rates established by the North Carolina Utilities Commission (the "Commission") for power that North Carolina utilities purchase from QFs. The rates are referred to as "avoided cost rates" because the Public Utilities Regulatory Policies Act of 1978 ("PURPA") provides that the rates to be paid to QFs should be at or below the utility's avoided costs. PURPA, however, leaves the specific methodology to be used to determine what constitutes avoided cost to the State's discretion. If, as is the case in North Carolina, a specific methodology is not proscribed by the legislature, then the appropriate methodology to be used is within the judgment of the Commission. Thus, while some discretion exists, calculating a utility's avoided cost (*i.e.*, determining the avoided capacity and energy cost to the utility of generating or purchasing the capacity and energy that the mandatory

QF purchase is replacing) is generally governed by a few well-accepted and established methodologies. For example, DEC and DEP have consistently used the "peaker methodology" as a means of determining avoided capacity and energy costs for purposes of setting the avoided cost rates they pay to QFs.

The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided cost for purposes of pricing power purchases from QFs. More specifically, the peaker methodology approximates a utility's avoided cost through generation production modeling. This approach assumes that when a utility's generating system is operating at equilibrium, the installed cost of a peaker (a simple-cycle CT plus the marginal energy costs of running the system will produce the marginal capacity and energy cost that a utility avoids by purchasing power from a QF. The Commission has also recognized the theoretical corollary of the peaker methodology, which provides that even if a utility's next planned unit is not a simple cycle peaker, the "peaker methodology" still represents a valid estimate of the utility's avoided costs. This fact is supported by the resource planning process itself in which building incremental peakers for capacity and relying on the remaining system for marginal energy is always an option within the planning process. Within the planning process, the utility only selects more expensive capital facilities, such as combined cycle baseload units, when the incremental efficiency of the unit (as compared to a simple cycle peaker) provides enough marginal energy value to more than compensate for the incremental capital. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost no greater than the capital costs of a peaker.

Q. **CAN YOU DESCRIBE THE AVOIDED COST RATES THAT DEC AND DEP ARE PROPOSING?**

A. DEC and DEP have proposed updated avoided cost rates for qualifying cogeneration and small power production facilities as part of this 2012 biennial filing. Listed below is a summary of these rates for non-hydroelectric facilities that are connected to the Utilities' distribution systems:

DEP Rates, ¢/kwh	**Variable**	**5-Year**	**10-Year**	**15-Year**
On-Peak Summer Capacity	2.529	2.617	2.754	2.879
On-Peak Non-Summer Capacity	2.006	2.076	2.185	2.284
On-Peak Energy	4.120	4.391	4.942	5.310
Off-Peak Energy	3.739	3.862	4.266	4.618
All-in Rate	4.654	4.857	5.356	5.752

DEC rates, ¢/kwh	**Variable**	**5-Year**	**10-Year**	**15-Year**
On-Peak Month – Capacity	6.88	7.12	7.51	7.87
Off-Peak Month – Capacity	1.06	1.09	1.15	1.21
On-Peak Energy	5.06	5.26	5.59	5.95
Off-Peak Energy	4.05	4.23	4.51	4.77
All-in Rate	4.94	5.15	5.48	5.80

The listed proposed rates would be applied to power supplied by a QF to the Utilities during the on-peak and off-peak hours and months as defined by the Utilities within their respective avoided cost tariffs. For illustrative purposes, the table below describes the combined capacity and energy rate (or "all in rate") a QF would be paid on a $/mwh basis if it operated at a 100% capacity factor over the contract term.

This example is for a non-hydro-electric QF delivering power to DEP's distribution system with a 1 MW capacity running at a 100% capacity factor and generating 8,760 megawatt hours annually. Under the five-year fixed rate contract proposed by DEP, the QF would receive $425,000 annually or $48.57/mwh of generation, calculated as follows:

DEP Rates for a 5 Year contract with a Non-Hydroelectric Facility at Distribution	Rate, $/mwh A	mwh B	Payment $ A x B
Total Generation		8,760	
On-Peak Summer Capacity	26.17	1,032	27,000
On-Peak Non-Summer Capacity	20.76	2,100	44,000
On-Peak Energy	43.91	3,132	138,000
Off-Peak Energy	38.62	5,628	217,000
Total			425,000

Q. WHAT IS THE DIFFERENCE BETWEEN THE VARIABLE AVOIDED COST RATES AND THE FIXED AVOIDED COST RATES PROPOSED BY THE UTILITIES?

A. PURPA provides that QFs have the option to sell their output at either "as available" variable rates that adjust more frequently or at fixed rates that are guaranteed for longer term periods. Accordingly, the Utilities have proposed an avoided cost rate structure that offers both variable rates that are adjusted with each updated rate filing as well as fixed rate structures that offer the QF the option of 5, 10, or 15 year fixed price rate offers. If the QF selects one of the longer-term fixed rate offers, they would not be subject to changes in their rate resulting from subsequent tariff filings during the duration of their fixed price contract. Both the "as available" rates and the fixed term rates provide QFs with a price that is based on the Utilities' avoided energy and capacity costs as calculated pursuant to the peaker method previously described. Recognizing that future avoided energy and capacity costs change with each filing as fuel prices and peaker costs change, the QF has the option to "lock in" a longer-term rate or take a short-term variable rate if they expect rates to rise in future filings. It should also be noted that the rates for both the "as available" and fixed long-term contracts are levelized. This means that the rates remain the same throughout the term of the contract, regardless of whether the contract is for two years or 15 years.

Q. HOW DO THE UTILITIES' PROPOSED AVOIDED COST RATES COMPARE TO THE AVOIDED COST RATES APPROVED BY THE COMMISSION IN THE PAST?

A. Compared to past rate filings, the Utilities' avoided cost rates generally have declined due to declining natural gas prices and declining cost per kw of simple cycle CTs. It is worth noting that both the energy and capacity prices have been volatile over the past several biennial filings. To illustrate this point, the following table shows the changes in the average annual avoided cost per kwh for a 10-year fixed price rate for non-hydroelectric QFs delivering to DEP's distribution system. This data shows how significant changes can be from one filing to the next. As with any commodity or capital intensive industry, short-term changes can be significant and should not be expected to move continuously in a single direction. However, it is important to note that the cumulative change from 2002 to 2012 still represents an average annual rate increase of 4.6%. The data illustrates biennial increases of more than 20% occurred between 2004 and 2006 and again between 2006 and 2008. These increases, which were well above normal inflation, were accepted as market driven due to sharp increases in natural gas prices and turbine construction costs. Correspondingly, a biennial decrease of the same magnitude should be equally acceptable and to a large degree expected.

DEP Biennial Proceedings	CSP-21A 2002	CSP-22A 2004	CSP-23B 2006	CSP-25 2008	CSP-27 2010	CSP-29 2012
All-in Rate, ¢/kwh	3.43	4.00	4.85	6.05	6.81	5.35

Q. **IS THE METHODOLOGY APPLIED BY THE UTILITIES TO DEVELOP THEIR PROPOSED AVOIDED COST RATES CONSISTENT WITH THE METHODOLOGY APPLIED IN PREVIOUS AVOIDED COST PROCEEDINGS?**

A. Yes. Both Utilities continued their long-standing practice of applying the peaker methodology to calculate their respective avoided costs. The Utilities also relied upon the same type of data that they have previously used for that purpose. However, the manner in which the Utilities applied that data changed due the timing of the closing of the Merger in 2012.

Q. WHY IS THE FACT THAT THE PROPOSED AVOIDED COST RATES WERE DEVELOPED AFTER THE DUKE-PROGRESS MERGER SIGNIFICANT?

A. Prior to the Duke-Progress Merger, DEC and DEP operated as totally separate, stand-alone companies. After the Merger closed on July 2, 2012, the Utilities were able to begin coordinating with each other and sharing previously-proprietary data and information regarding best practices and procedures. DEC's and DEP's current avoided cost rate filings represent the first time that the Utilities were able to develop a filing in a cooperative manner based on such shared information and best practices.

Q. PLEASE DISCUSS THE RATIONALE FOR THE UTILITIES' POST-MERGER COLLABORATIVE AND COORDINATED EFFORTS.

A. One of the significant benefits of the Duke-Progress Merger is that it allows DEC and DEP to share information regarding their operations, projections, business practices and procedures. The pooling of information and comparing of respective practices and procedures improves processes and operations, which results in increased efficiencies. In fact, the Commission's June 29 Merger Order[1] contains several examples that show how such collaboration to develop best practices for the benefit of the Utilities' respective customers was not only planned by DEC and DEP, but in some cases required in the Commission's approval of the Duke-Progress Merger. For example, the Merger Order recognized – as merger-related benefits to customers – that

[1] *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket Nos. E-2, Sub 988 and E-2, Sub 986 (June 29, 2012)

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DEC and DEP planned to collaborate and leverage each other's best practices, including:

- DEP's sharing of its proprietary coal blending techniques with DEC, which was expected to produce an estimated $183.9 million in fuel savings over five years;
- DEP's plan to adopt certain best operating practices from DEC with respect to the Utilities' hydro-electric facilities to achieve operational efficiencies and cost savings; and
- Both Utilities plan to engage in a coordinated renewable energy procurement processes that would provide a direct benefit to customers through lower Renewable Energy Portfolio Standard ("REPS") compliance costs.

In certain instances, the Commission's Merger Order even directed the Utilities to make "every reasonable effort to incorporate each other's best practices into its own practices to the extent practicable," as in the case of Regulatory Condition 11.2, governing Service Quality. As the foregoing examples illustrate, the Utilities and the Commission expected and intended that DEC and DEP would share information and compare practices in an effort to improve their efficiency and effectiveness.

Q. **CAN YOU DESCRIBE THE UTILITIES' THINKING IN ADOPTING A COLLABORATIVE PROCESS AND COORDINATING THE DEVELOPMENT OF THEIR PROPOSED AVOIDED COST RATES?**

A. The process of developing avoided cost rates is particularly suited to being improved by the pooling of information and the reassessment and coordination of practices and analytical approaches. Both Utilities have historically used the same peaker methodology to establish a proxy for their respective avoided costs. Determining avoided costs using the peaker methodology is dependent upon the application of estimates and projections, such as estimating the cost of constructing a new CT and long-term projections of natural gas prices. As a result, developing avoided cost rates requires the application of assumptions to data and projections based on judgment and experience. Thus, although DEC and DEP had historically developed reasonable and appropriate processes for calculating their avoided cost rates as stand-alone utilities, the Duke-Progress Merger allowed them to compare their methods and assumptions, to identify differences in the approaches that they used and to develop a best practices approach. This is precisely what the Utilities did in developing their proposed avoided cost rates filed for approval.

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Q. DID THESE COLLABORATIVE EFFORTS IMPACT DEC'S AND DEP'S DEVELOPMENT OF THEIR PROPOSED AVOIDED COST RATES?

A. Yes, which is certainly to be expected. Whenever newly-merged organizations begin to coordinate their activities and share information, improvements in processes and practices should occur. In some cases, the changes may be due to selecting one of the organization's approaches as a best practice or they may come from a reassessment of long-standing assumptions and practices resulting in a new and improved approach for both organizations.

Q. CAN YOU PROVIDE EXAMPLES OF THE CHANGES IN DEVELOPING AVOIDED COST RATES THAT RESULTED FROM THE UTILITIES' POST-MERGER COLLABORATION?

A. Yes. Prior to the close of the Merger, DEC and DEP separately developed their proprietary long-term gas price projections for their 2012 IRPs. As part of their post-Merger collaboration, DEP and DEC shared information regarding these projections and, as a result of that process, DEP adopted DEC's long-term gas price forecast as a more robust process for projecting future gas prices. It is noteworthy that DEC's long-term gas price forecast was higher than DEP's forecast. Consequently, DEP's adoption of DEC's gas price forecast resulted in an increase in the energy component of DEP's proposed avoided cost rates.

With regard to the capacity component of the Utilities' proposed avoided cost rates, DEC and DEP had separately commissioned cost studies for the construction of new CTs prior to closing the Merger. Those studies were conducted completely independent of each other by two different engineering firms and were both completed prior to the Merger in mid-2012. Once the Utilities were able to share these studies with each other, it became clear that both studies included cost estimates for a particular type of CT manufactured by General Electric ("GE"). DEC had based the CT costs used in its 2012 IRP on that GE unit, but DEP had used the cost estimates for Siemens units in its 2012 IRP. Because DEP now had access to two independently-prepared estimates for the GE model, DEP concluded that these estimates provided the most reliable information on CT costs for purposes of calculating avoided cost. DEP, therefore, based its proposed avoided cost rates on the GE model CT, which had a higher estimated cost per kw than the Siemens model it used in its 2012 IRP.

The collaborative process also gave the Utilities the opportunity to examine certain assumptions that they had previously employed. For example, DEC and DEP had assumed 30-year and 25-year useful lives for CTs in their respective 2012 IRPs. However, as part of the collaborative process, they concluded that a 35-year useful life more accurately reflected their operating experience with those types of facilities and employed that assumption in calculating their proposed avoided cost rates.

The collaborative process also produced a change related to the use of contingency adders in estimating the cost of installing a new CT. This is discussed in more detail later in my testimony, but in general, the Utilities discovered during the collaborative process that they had used significantly different assumptions regarding contingency adders for CT construction costs in their respective 2012 IRPs. DEP had included a contingency adder of about 5% in its CT cost estimate, whereas DEC assumed a contingency adder of approximately 30%. Given this difference, the Utilities worked together and after considering their actual experience in constructing combustion turbine-based generation and the purpose of the avoided cost filing, they concluded that DEP's approach of using a 5% contingency adder more closely reflected actual experience and was more appropriate for avoided cost purposes.

In sum, the process of DEC and DEP working together and sharing information and comparing their respective practices did result in changes in certain aspects of how they calculated their avoided cost rates. Those changes, however, were merely the natural result of ordinary post-merger collaboration. More importantly, those changes improved the Utilities' avoided cost processes and resulted in better supported and more appropriate avoided cost rates. This result is consistent with the purpose of this proceeding and benefits the Utilities' customers by ensuring that avoided cost rates are based on the best information and practices available.

Q. **CAN YOU BREIFLY EXPLAIN WHY THE UTILITIES DID NOT APPLY THIS COLLABORATIVE PROCESS TO THE DEVELOPMENT OF THEIR 2012 IRPS?**

A. Time constraints simply did not allow for such collaboration. First, the complex technical process of developing an IRP necessarily began months before the closing of the Duke-Progress Merger. After the closing, the amount of time before the required September 4, 2012 IRP filing date did not allow for DEC and DEP to begin effectively coordinating their IRPs. In fact, the introductory section to both DEC's and DEP's 2012 IRPs specifically stated that the timing of the Duke-Progress Merger had prevented collaboration in IRP planning and coordination of inputs between the Utilities regarding their respective 2012 IRPs. Therefore, DEC's and DEP's 2012 IRPs, filed two months after the Duke-Progress Merger closed, were based upon the information and practices that each company had separately developed and relied upon prior to the merger. However, the Utilities also made clear in their 2012 IRP filings that, in the future, it was their intent to collaborate to promote best practices between the Utilities and, where appropriate, to establish consistency between their analytical approaches and assumptions for future filings. To that end, DEC and DEP, working together, have developed consistent data and assumptions in the development of their respective 2013 IRPs. Furthermore, as it relates to CT costs, the data that the Utilities are using in their 2013 IRPs is generally consistent with the CT costs underlying the avoided cost rates they have proposed in this proceeding.

Q. **SPECIFICALLY RELATING TO THE AVOIDED COST RATE DEVELOPMENT, WHY IS SUCH COLLABORATION BENEFICIAL?**

A. Post-merger, DEC and DEP are striving for efficiency and consistency in system operations and in new generation development and construction. From an operations perspective, the joint dispatch arrangement between DEC and DEP is reducing their marginal production costs. The Utilities also have consolidated their major projects organization, which combines the construction experience of DEC and DEP allowing for consistent and efficient construction practices. As a result, the Utilities' marginal energy costs, as well as their marginal construction costs, are becoming more efficient and consistent with one another. It follows that strong collaboration on avoided cost rate development is essential to ensure that the consistency that is being achieved in the field is also reflected in the Utilities' respective avoided cost rates. Differing assumptions and analytic methods between the utilities would only serve to incent QF development in one of the Utilities' service territory over the other based on arbitrary differences in assumptions rather than on true economic market signals.

Q. **WHAT ARE YOUR CONCLUSIONS REGARDING THE UTILITIES' INTENT TO COLLABORATE AND COORDINATE THEIR OPERATIONS IN THE FUTURE?**

A. The collaboration and coordination of information that I have described is completely consistent with the Commission's Merger Order and the Regulatory Conditions contained therein. The Utilities strongly believe that the opportunity for collaboration and the sharing of information created by the Merger has already allowed them to coordinate and develop new best practices, eliminate duplication, and achieve efficiencies across DEC's and DEP's utility operations for the benefit of their customers. Accordingly, the Utilities intend to apply this cooperative approach in the future, including in the development of their 2013 IRPs.

II. <u>DEVELOPMENT OF THE UTILITIES' PROPOSED AVOIDED CAPACITY RATES</u>

Q. HOW ARE AVOIDED CAPACITY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. The peaker methodology is designed to produce the cost of future capacity avoided through a hypothetical QF purchase by combining the full cost of a CT with a utility's marginal system production costs. The Commission has long held that for a utility generating system operating in equilibrium the cost of a hypothetical CT combined with the system's marginal energy cost is regarded as an appropriate measure of the system's total marginal cost. As discussed previously, even if the actual unit to be added is a base load unit, the cost of the hypothetical CT combined with marginal system production cost is a reasonable proxy for the utility's total avoided costs. If a baseload unit is the next resource added to a utility's system, it was selected because it produces energy at below the system marginal energy cost. Those energy savings offset the higher capital cost of that baseload facility. In contrast to the "next unit" approach, the peaker methodology couples the lower capital cost of a CT with the higher energy cost of marginal energy to set the system avoided cost rate.

Q. PLEASE STATE THE INSTALLED CT COSTS THAT THE UTILITIES USED IN CALCULATING THEIR AVOIDED CAPACITY RATES.

A. The Utilities used the same overnight CT cost in calculating their proposed avoided capacity rates. After the application of utility-specific factors, such as financing costs, return on equity, and property tax assumptions, 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 CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. HOW DID THE UTILITIES DETERMINE THE INSTALLED CT COST TO BE USED IN THEIR AVOIDED COST RATES?

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) for a new CT from two leading engineering firms – Burns & McDonnell ("B&M") and Sargent & Lundy ("S&L").

Although DEC and DEP could not share information relating to the studies prior to the closing of the Merger, they did so in the months after closing. In reviewing the two studies, the Utilities observed that both S&L and B&M had provided cost estimates for a single site consisting of four GE 7FA.05 simple cycle CTs. Because this provided the Utilities with two independently prepared estimates for the same units and configuration, DEC and DEP concluded that these estimates provided the most reliable information on CT costs for purposes of calculating avoided cost. That conclusion was supported by the fact that the cost estimates for four GE 7FA.05 units developed by S&L and B&M were very similar, despite the studies having been conducted independently of each other. Rather than choose between the S&L and B&M cost estimates, DEC and DEP decided that the most reasonable approach was to take the average of the two cost estimates.

Q. YOU HAVE TESTIFIED THAT THE B&M AND S&L STUDIES PRODUCED SIMILAR COST ESTIMATES FOR A SINGLE SITE CONSISTING OF FOUR GE 7FA.05 SIMPLE CYCLE CTS. CAN YOU ELABORATE ON THAT POINT?

A. The easiest way to see the consistency between the B&M and S&L cost estimates is to compare the overnight cost estimates that they provided for four GE 7FA.05 simple cycle CTs with no allowance for contingency or financing costs. This eliminates the effect of any utility-specific factors on the cost to construct (e.g., different rates of return and discount rate) and places the estimates on a comparable basis. Once adjusted for consistent assumptions regarding owners cost and ancillary infrastructure, the estimate based on the B&M study resulted in an overnight cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, while the estimate based on the S&L study resulted in an overnight cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The consistency of those estimates produced a high degree of confidence that they accurately reflected a sound estimate of CT construction costs. As noted above, the Utilities decided to average these estimates rather than select one or the other.

Q. ARE THE INSTALLED CT COSTS THAT THE UTILITIES USED IN THEIR PROPOSED AVOIDED COST RATES A REASONABLE ESTIMATE OF THE COST OF INSTALLING SUCH UNITS?

A. Yes. As noted above, DEP's avoided capacity rates are based on an installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and DEC's avoided capacity rates assume installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Those figures are reasonable estimates of the average cost of four conventional CT units at a single site.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION?

A. The primary basis for that conclusion is that the installed CT costs used by the Utilities in their avoided capacity rates are based on recent cost studies developed by two experienced engineering firms. These are the same cost studies that the Utilities relied upon in developing their respective 2012 IRPs. Moreover, the fact that these two engineering firms, working independently of each other, produced CT cost estimates that were so similar only serves to reinforce the conclusion that those estimated installed CT costs are good estimates of the cost to build such CTs.

Q. DO YOU HAVE ANY OTHER SUPPORT FOR YOUR CONCLUSION THAT THE INSTALLED CT COSTS THAT THE UTILITIES USED IN THEIR PROPOSED AVOIDED COST RATES ARE A REASONABLE ESTIMATE OF THE COST OF INSTALLING SUCH UNITS?

A. Yes. After the Utilities filed their avoided cost rates in this docket, the North Carolina Sustainable Energy Association ("NCSEA"), the Public Staff – North Carolina Utilities Commission ("Public Staff") and the Renewable Energy Group ("REG") (collectively, the "Intervenors") raised questions about the reasonableness of the CT cost estimates reflected in the B&M and S&L studies and in DEC's and DEP's avoided cost rates. The Intervenors suggested that the CT cost estimates underlying the Utilities' avoided capacity rates are too low.

In light of the questions raised regarding the CT costs used in their avoided capacity rates, the Utilities sought out independent sources of information to assess the validity of CT cost data upon which they relied. To that end, the Utilities reviewed current installed CT cost data published by the Energy Information Administration ("EIA"), the Electric Power Research Institute ("EPRI"), and the Brattle Group. The Company extensively discussed how this independent industry cost data supports the reasonableness of the installed CT cost used in developing the Utilities' avoided cost rates in Section III.B. of our Joint Reply Comments. Limited adjustments were needed to put the data on a comparable basis with the CT cost data used in the Utilities' avoided cost rates. Specifically, an adjustment was made to reflect the fact that avoided costs were based on the average cost of a CT at a four-unit site. The EIA data was for a single-unit site, EPRI presented data for a single-unit site and three-unit site and the Brattle Group data was for a two-unit site. An adjustment was also made to bring the Brattle Group data back to 2012 dollars because the Brattle Group's estimate was for 2015 overnight installed costs. As Section III.B. of our Joint Reply Comments describes, the cost estimates produced by EIA, EPRI, and the Brattle Group are within 7% of the cost data used by the Utilities in this case.

In addition, the Utilities looked to the 2012 *Gas Turbine World Handbook* (*"2012 GTW Handbook")*. Although the *2012 GTW Handbook* includes only CT equipment cost, the information published by *Gas Turbine World* also aligns with the S&L and B&M studies and, if anything, suggests that a lower CT cost could be justified. *Gas Turbine World* publishes cost estimates of CT equipment, as opposed to total CT project costs. According to the *2012 GTW* Handbook, the balance of the installation costs can be 60-100% of the equipment cost. The Utilities, therefore, increased *Gas Turbine World's* equipment cost estimate for a GE 7FA.05 by 100% and applied that cost to a four-unit configuration, which produced an installed cost that was actually 16% ***lower*** than the installed costs used by the Utilities in their avoided cost rate filings.

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In summary, the Utilities considered the B&M Study, the S&L study, as well as validation from contemporaneous, independently developed industry information from EIA, EPRI, the Brattle Group, and *Gas Turbine World*. All of this information from those highly respected sources led to the same conclusion – the CT cost data that DEC and DEP used to develop their avoided cost rates is reasonable, appropriately reflects the expected cost of building such units, and in no way understates the Utilities' avoided costs.

Q. SUBSEQUENT TO THE FILING OF JOINT REPLY COMMENTS, HAVE THE UTILITIES TAKEN ANY FURTHER STEPS TO VERIFY THE CT COST DATA USED IN THE DEVELOPMENT OF THEIR AVOIDED COST RATE FILINGS?

A. Yes. Given the debate over CT costs used in the Utilities' avoided cost rates, the Utilities engaged Black and Veatch ("B&V") to conduct a third independent estimate of the cost to construct a four-unit simple cycle GE7FA.05 facility in North Carolina. B&V is a well-known engineering, procurement and construction firm within the energy industry. B&V's results will be presented independently in the testimony of Theodore Pintcke, Vice President of Project Development with B&V. While Mr. Pintcke's testimony speaks for itself, his conclusions further support the reasonableness of the CT costs used by the Utilities to develop their avoided capacity rates.

III. SPECIFIC CONCERNS REGARDING THE INSTALLED CT COSTS UNDERLYING THE UTILITIES' AVOIDED CAPACITY RATES

Q. YOU MENTIONED IN YOUR PREVIOUS RESPONSE THAT THE INTERVENORS HAVE RAISED QUESTIONS CONCERNING THE INSTALLED CT COSTS USED BY THE UTILITIES IN CALCULATING THEIR AVOIDED CAPACITY RATES. CAN YOU SUMMARIZE THEIR CONCERNS AS YOU UNDERSTAND THEM?

A. I have reviewed the filings made by the Intervenors in this docket, and based on that review, my understanding is that the Intervenors believe that the Utilities should be required to use higher installed CT costs, which would translate into higher avoided capacity rates to be paid to QFs.

Generally stated, the Intervenors have not argued that the installed CT costs used by the Utilities are out of line with current market costs to build a CT. Rather, they have focused on the fact that the installed CT costs applied by the Utilities in the present case are lower than the CT costs used by the Utilities in previous proceedings, particularly previous avoided cost proceedings and the 2012 IRP proceeding. For whatever reason, those comments appear to take issue with the fact that the process of developing the Utilities' avoided cost rates (including the post-Merger collaboration between DEC and DEP) resulted in a reduction in the capacity component of the Utilities' avoided cost rates.

Q. HOW DO YOU RESPOND TO THE SUGGESTION THAT THE UTILITIES MADE DELIBERATE CHANGES IN THEIR AVOIDED COST CALCULATIONS IN ORDER TO LOWER THEIR AVOIDED COST RATES?

A. There is absolutely no merit to any such suggestion. In this case, as in every avoided cost proceeding, the Utilities have proposed avoided cost rates based on the best information available to them. Any suggestion that the Utilities engaged in a concerted effort to depress their avoided cost rates is misguided and is addressed in Section II of the Utilities' Joint Reply Comments and in the Direct Testimony of Kendal C. Bowman filed in this docket.

The facts demonstrate that the Utilities made numerous decisions in developing their avoided cost rates that, in fact, increased those rates. For example, DEP adopted DEC's higher projected gas prices, which resulted in a higher avoided energy cost rate than would have been produced by the lower gas price projections used in DEP's 2012 IRP. Similarly, neither DEC nor DEP incorporated the effect of their Joint Dispatch Agreement ("JDA"), which would have reduced the avoided energy costs for both Utilities.

Decisions of this type were not confined to the energy component of the proposed avoided cost rates. For example, as I explained above, DEP chose to base its avoided capacity cost on the averaged B&M study and S&L study cost of installing GE 7FA.05 CTs solely to ensure that it was using the best supported data available. DEC did so although the smaller Siemens 5000F has a lower installed cost on a $/kw basis.

A final example to rebut the assertions that the Utilities inappropriately attempted to push down their avoided cost rates is DEP's decision to use a 12.75% return on equity ("ROE") as an input to its avoided capacity rate calculation. At the time that DEP made its avoided cost filing, 12.75% was its then-currently approved ROE. DEP could have asserted that the 11.25% ROE requested in DEP's October 12, 2012, rate case application was the more appropriate ROE to use in determining DEP's avoided cost because its authorized ROE was not likely to be higher than 11.25% on a going forward basis. In fact, DEP's requested 11.25% ROE – a full 150 basis points below DEP's historical 12.75% ROE – had already been used as an input to DEP's projected CT costs in its 2012 IRP. If DEP had intended to push down its proposed avoided cost rates, it would have applied the lower ROE of 11.25% because using a lower cost of equity decreases the estimated cost to construct a new CT. However, DEP concluded that, while a projection of its likely ROE after its rate case was appropriate for long-term resource planning purposes, it should continue to apply its currently approved (albeit higher) ROE in calculating its avoided cost rates. As a result, DEP calculated its avoided capacity rates using of its then-current 12.75% ROE despite the virtual certainty that the Commission would soon approve new base rates for DEP based on a substantially lower ROE.

It should also be noted that since the filing of DEP's avoided cost rates, the Commission has issued an Order in DEP's aforementioned rate case approving a settlement that included a 10.2% ROE. Pursuant to this Order, DEP's rates are now designed to allow DEP to recover a ROE of 10.2%, which means that DEP's assumed cost of equity is also 10.2% - a full 255 basis points lower than the ROE that was used to calculate DEP's avoided capacity rates.

Q. IS DEP REQUESTING TO REVISE ITS AVOIDED COST RATES TO REFLECT ITS NEW AUTHORIZED ROE?

A. Despite the significant difference between DEP's current ROE of 10.2% and the 12.75% ROE used in its avoided cost calculations, DEP is not seeking to reduce its proposed avoided cost rates to reflect its lower, currently-approved ROE at this time. DEP believes that in the present case, the process is better served by following the approach of setting avoided cost rates based on the best information available when the avoided cost filing is made. This should further rebut any suggestion that the Utilities have any interest in artificially depressing their avoided cost rates. However, the Commission should take note that DEP's avoided capacity rates use an inflated ROE, and therefore, arguably overstate the capacity costs that DEP will avoid by purchasing power from QFs in the future. DEP requests that the Commission bear this factor in mind as it considers the requests of other parties to further increase DEP's avoided capacity costs.

Q. **HOW DO YOU RESPOND TO CONCERNS REGARDING THE DIFFERENCES BETWEEN THE INSTALLED CT COSTS USED IN THIS PROCEEDING AND THE INSTALLED CT COSTS USED IN PAST AVOIDED COST PROCEEDINGS?**

A. CT cost data developed in 2010 and earlier has little bearing on the current cost of constructing a CT. With the passage of time, technology advances and market conditions change. As a result, it is not surprising that there are differences between the CT costs used in previous biennial avoided cost proceedings and the CT costs used in the present case. More relevant to the avoided capacity rates proposed in this docket is the available contemporary and well-supported CT cost data. As I have described earlier in my testimony, the installed CT costs used in the Utilities avoided capacity rates is based on two current cost studies and further supported by several industry sources. Also, there have been prior biennial filings over the past decade that have had cost increases from one filing to the next of a greater magnitude than the current decrease. In those instances, no argument was made that changes from one filing to the next should be used as a measure of validation for the current filing. Consequently, the Utilities again emphasize for the Commission that references to past avoided cost filings cast no doubt on the reasonableness or accuracy of the installed CT costs used by the Utilities in this case.

Q. HOW DO YOU RESPOND TO CONCERNS REGARDING THE DIFFERENCES BETWEEN THE INSTALLED CT COSTS USED IN THIS PROCEEDING AND THE INSTALLED CT COSTS USED IN THE UTILITIES 2012 IRPS?

A. Based on the Intervenors' filed comments, it appears that their primary concern is that the installed CT costs used to set the Utilities' avoided capacity rates are lower than the CT costs that were used in developing the Utilities' 2012 IRPs. At the outset, it must be noted that, at least with regard to DEP, their premise is factually wrong. The installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** used in calculating DEP's avoided cost rates is actually higher than the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** average cost for a four-unit site (based on a weighted average rate of 205 MW per unit and other assumptions) used in DEP's 2012 IRP. This comparison was explained in detail in Section III.A. of the Utilities' Joint Reply Comments, and shows that when evaluated on a comparable basis, the CT costs used to develop DEP's avoided cost rates are higher than the CT costs used in DEP's 2012 IRP. In arguing to the contrary, the Intervenors appear to be making what is, in effect, an apples-to-oranges comparison. For example, in its Initial Statement, the Public Staff refers to an installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as the CT cost used in DEP's 2012 IRP. That figure, however, is derived from B&M's cost estimate for the first Siemens 5000F unit at a four-unit site. Consequently, it cannot be compared directly to the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] cost used by DEP for avoided cost purposes because that figure is the average cost of constructing all four units at a four-unit site. A more appropriate comparison would be to compare the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] cost of the first Siemens to the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] cost that B&M estimated for the first GE 7FA.05 at a four-unit site. Regardless, DEP unquestionably used higher CT costs in its avoided capacity rates than it used in its 2012 IRP.

With regard to DEC, it is accurate that the installed CT costs that DEC used to calculate its proposed avoided capacity rates were substantially lower than the CT costs it used in developing its 2012 IRP. As previously noted, DEC's avoided capacity rates assume installed CT cost of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] while DEC used installed CT cost of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in its 2012 IRP. That difference is explainable, however, and does not indicate any flaw or error in the development of DEC's avoided capacity rates.

Q. PLEASE EXPLAIN WHAT FACTORS CAUSED THIS SIGNIFICANT DIFFERENCE.

A. There are two factors – both of which are discussed extensively in Section IV of the Utilities' Joint Reply Comments – that account for almost all of the change in the estimated CT cost from DEC's 2012 IRP to its proposed avoided capacity rates: 1) the elimination of a $35 million spreadsheet error; and 2) the reduction of the contingency adder from approximately 30% (used in DEC's 2012 IRP) to 5%. When the CT cost from the S&L study is adjusted by removing the $35 million error and reducing the contingency adder to 5%, the result is an installed CT cost of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Comparing that figure to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** CT cost used in DEC's avoided cost calculation shows that the spreadsheet error and the excess contingency adder account for 90% of the difference between the CT cost used in DEC's IRP and the CT cost used in developing DEC's avoided cost rates.

Q. PLEASE EXPLAIN HOW THE "SPREADSHEET ERROR" OCCURRED.

A. The spreadsheet error resulted from DEC's inclusion of a separate line item for owner's cost in calculating the CT costs used in its 2012 IRP. As a result, the CT cost included in DEC's 2012 IRP inadvertently double-counted owner's cost, resulting in the mistaken addition of $35 million to the CT construction cost used in DEC's 2012 IRP. Correcting this mistake removed the excess $35 million from the construction cost.

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Q. PLEASE DESCRIBE THE IMPACT OF DEC'S DECISION TO CHANGE THE CONTINGENCY ADDER USED FOR DEVELOPING ITS CT COSTS.

A. DEC's reduction of the contingency adder is the more significant factor contributing to the difference between the CT costs in DEC's avoided capacity rates and its 2012 IRP. The effect of using a 5% contingency adder (compared to the much higher contingency adder used in DEC's 2012 IRP) reduced DEC's estimated CT construction costs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Although the change was significant, it was carefully considered based on operational experience and is appropriate.

Q. WITH REGARD TO THE CHANGE IN THE CONTINGENCY ADDER ADOPTED BY DEC, CAN YOU BEGIN BY DEFINING CONTINGENCY ADDER AND EXPLAINING ITS PURPOSE?

A. A contingency adder (or contingency allowance) is an amount added to a project cost estimate to account for uncertainties and risks. It is usually expressed as a percentage of the project cost estimate. For example, in this testimony, the contingency adders I have referred to are expressed as a percentage of the total project cost estimate, excluding AFUDC. One definition of contingency that I find useful for the present case is the one used by the EIA. EIA uses contingencies in its annual estimate of the cost of installing various types of electric generating facilities and describes the purpose of the contingency adders it uses as follows:

> A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

The Utilities noted this definition in Section IV.B. of their Joint Reply Comments, and provided the specific EIA reference in Attachment D to those Joint Reply Comments.

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.

Q. WHY DO YOU BELIEVE 5% IS THE BETTER CONTINGENCY ADDER FOR PURPOSES OF THE UTILITIES' AVOIDED CAPACITY RATES?

A. Simply put, a contingency adder of the magnitude used in DEC's 2012 IRP reflects a "worst case scenario" approach to estimating the cost of installing a new CT. Using a contingency adder of that size produces an installed CT cost that assumes virtually every risk and uncertainty would turn against the project.

Conversely, a 5% contingency adder is more indicative of an "expected case scenario" for projects such as the construction of conventional, simple-cycle CTs. Such projects involve well-understood and comparatively simple technologies. Thus, conventional CT construction projects are not prone to the kind of unforeseen risks and circumstances that would warrant a large contingency adder.

Q. **DO YOU HAVE ANY SUPPORT FOR YOUR CONCLUSION THAT A 5% CONTINGENCY ADDER REFLECTS AN "EXPECTED CASE SCENARIO" IN THE CONTEXT OF BUILDING A CONVENTIONAL CT?**

A. Yes. As extensively discussed in Section IV.A. of the Utilities' Joint Reply Comments, all of the Utilities' recent experience with constructing combustion turbine-based generation points to the same conclusion – large contingency adders are not warranted in estimating the cost of those types of projects.

Since 2009, DEP has completed three projects involving plants with combustion turbine technology – the Wayne County CT, the Smith combined cycle ("CC") plant, and the recently completed Lee CC. The original project estimate for those projects included contingency adders of 3-5%. Similarly, the initial cost estimate for DEP's current Sutton CC project includes a contingency adder of 5%. Moreover, of these four projects, only the Wayne County CT required any of its contingency. As shown on Confidential Exhibit C to the Utilities' Joint Reply Comments, finalized construction costs for the Wayne County CT were 1% less than DEP's initial project estimates, which means that it only used part of the contingency adder included in its initial project estimate. On the other hand, as Confidential Exhibit C shows, that the Smith CC, the Lee CC and the Sutton CC have been or are expected to be for substantially less than their initial project estimates, using none of their contingency.

DEC's recent experience combustion turbine technology projects is consistent with DEP's experience. In November 2011, a new combined cycle unit began commercial operation at DEC's Buck Combined Cycle Station and, in December 2011, DEC added a combined cycle unit to the Dan River Combined Cycle Station. The initial project estimates for both the New Dan River and Buck units contained contingency adders of 4%. As presented in Confidential Exhibit C to the Utilities Joint Reply Comments, the cost for DEC's new unit at Buck is projected to be within 1% of its initial cost estimate. Although this means that the Buck project consumed all of its 4% of contingency, it would have come in at budget if the contingency adder had been 5%. The Dan River unit, on the other hand, is projected to be completed at 8% below the initial project estimate, which means that it used none of its contingency. Thus, DEC's recent combustion turbine technology projects either required only a 5% contingency or used none of the contingency allowance included in the initial project estimate.

In sum, both DEC's and DEP's actual experience over the past five years in constructing six combustion turbine technology generation projects shows that a reasonable contingency adder is between 3% and 5%, and in most instances, DEC and DEP have been able to complete construction and achieve commercial operation using less contingency than projected or none at all. Indeed, the Utilities have found that little or no contingency adder is required even when constructing combined cycle facilities, which are more complex than the simple cycle CTs that serve as the basis for the Utilities' avoided capacity rates.

Q. **WAS THE UTILITIES' ACTUAL EXPERIENCE IN CONSTRUCTING COMBUSTION TURBINE-BASED GENERATION TAKEN INTO ACCOUNT IN MAKING THE DECISION TO USE A 5% CONTINGENCY ADDER IN CALCULATING DEC'S AVOIDED CAPACITY RATES?**

A. Yes, it was. As the EIA definition set forth earlier in my testimony suggests, in setting a reasonable contingency adder, it is important to consider real world experience in order to assess the risk of unforeseen events. This is precisely what DEC and DEP did in this case.

Q. **WERE THERE ANY OTHER FACTORS THAT INFLUENCED THE DECISION TO USE A 5% CONTINGENCY ADDER FOR THE CT COSTS REFLECTED IN DEC'S AVOIDED CAPCITY RATES?**

A. Yes. Another factor was that the "worst case scenario" approach to contingency, such as was applied in DEC's 2012 IRP, is not appropriate for purposes of setting avoided cost rates.

Q. WHY WOULD A "WORST CASE SCENARIO" APPROACH TO INSTALLED CT COSTS BE INAPPROPRIATE FOR AVOIDED COST PURPOSES?

A. Avoided cost rates have a direct impact on customers. Any cost that is added to a utility's avoided cost rates translates into higher payments to QFs, which ultimately are passed through to the utility's customers. Moreover, one of the fundamental tenets of PURPA is that the rates paid to QFs must not exceed the costs that a utility avoids by buying power from a QF. It follows that avoided capacity rates should reflect the capital costs that the utility reasonably expects to avoid if it purchases power from a QF rather than building its own generation. A "worst case scenario" approach to estimating the cost of building a CT simply cannot be squared with any of those principles. By definition, it produces avoided capacity rates far in excess of the capacity cost the Utilities could reasonably expect to avoid.

Even assuming that a "worst case scenario" approach to using contingency adders was appropriate in a planning context, it cannot be justified as a basis for setting avoided cost rates. In the case of planning utility generation, using a high contingency factor for planning purposes has no impact on customers because only the actual costs of the project (which may or may not include the full amount of the contingency) can be included in rates. This is consistent with the Utilities' experience with combustion turbine-based construction projects, which often do not even need the small contingency adders included in the initial project estimates. Conversely, for purposes of determining avoided costs, the entire contingency amount gets included in the avoided cost rates, effectively assuming that the entirety of the contingency adder would be consumed by the project. Thus, applying a "worst case scenario" approach to calculating installed CT costs for avoided cost purposes creates a two-fold problem. First, it assumes a high contingency adder that is inconsistent with the Utilities' actual experience. Second, it effectively assumes that all of the overstated contingency adder is consumed by the project, which is often not the case, thereby creating an avoided cost capacity rate in excess of the expected avoided cost.

In summary, given that every dollar of contingency included in CT cost estimates gets included in the avoided cost calculation and PURPA's clear directive that such costs shall not exceed the costs a utility avoids when purchasing power from a QF, it should be clear that avoided cost calculations must be grounded in reasonable expectations of what those costs would likely be. Applying an overly large contingency factor to estimate CT costs can only serve to overstate avoided capacity costs in direct contravention of the intent of PURPA.

Q. **APART FROM THE MATTERS THAT YOU HAVE ALREADY ADDRESSED, ARE THERE ANY OTHER ISSUES ASSOCIATED WITH THE INSTALLED CT COSTS ASSUMED IN THE UTILITIES' AVOIDED CAPACITY RATES THAT YOU WISH TO DISCUSS?**

A. Yes, there is one additional issue that I would like to address briefly relating to the installed CT costs - the Utilities' use of a 35-year useful life for CTs in calculating their avoided capacity rates.

Q. **WITH REGARD TO THE ASSUMED USEFUL LIFE OF CTS, PLEASE EXPLAIN HOW THAT FACTOR AFFECTS THE CT COSTS USED IN CALCULATING AVOIDED CAPACITY RATES.**

A. Under the peaker methodology, the capacity component of avoided costs is driven primarily by the cost to install a new CT. That cost is levelized over the CT's useful life in order to set the avoided capacity rates. Thus, a longer useful life provides a longer period of time over which to spread the capital costs of the CT, which translates to a lower annualized capital cost and lower avoided capacity rates. For example, assuming two CTs with identical construction costs and identical capacity ratings, if one CT is expected to operate for 20 years and the other is expected to operate for 40 years, the annual capital cost of the 40-year CT will in effect be lower because its capital costs will be spread over a longer time period. Similarly, for purposes of avoided cost rates, an assumption of a longer useful life for a CT translates to lower annual capital costs and lower avoided capacity rates, all other things being equal. A simple analogy would be two homes that cost the same amount, but one is financed over 15 years and the other over 30 years. The annual mortgage payments for the home financed over 30 years will be smaller than the mortgage payment for the home financed over 15 years.

Q. **YOU MENTIONED THAT THE UTILITIES ASSUMED A USEFUL CT LIFE OF 35 YEARS IN THEIR AVOIDED COST CALCULATIONS. HOW DOES THAT COMPARE WITH THE USEFUL LIFE ASSUMPTIONS THAT THE UTILITIES HAVE USED IN PREVIOUS AVOIDED COST RATE PROCEEDINGS AND IN THEIR 2012 IRPS?**

A. The use of a 35-year useful life represented a change for both DEC and DEP. In previous avoided cost rate filings and the 2012 IRP, DEC had typically used a 30-year useful life for CTs and DEP had applied a 25-year useful life.

Q. **WHY WAS THE ASSUMPTION REGARDING THE USEFUL LIFE OF CTS CHANGED FOR PURPOSES OF CALCULATING THE UTILITIES' AVOIDED COST RATES IN THIS PROCEEDING?**

A. As noted above, DEC and DEP historically applied different useful life assumptions for CTs in developing their respective avoided costs. Given the disparity in those assumptions, it was logical for the Utilities to reassess them as part of their collaborative avoided cost development process. As a result of that collaboration, both Utilities concluded that a 35-year useful life for CTs was more reasonable and both applied that assumption in calculating their proposed avoided cost rates.

Q. WHY IS 35 YEARS A MORE REASONABLE ASSUMPTION FOR THE USEFUL LIFE OF A CT THAN 30 YEARS OR 25 YEARS?

A. Avoided capacity rates should reflect the capital costs the purchasing utility actually avoids if it purchases power from a QF rather than generating the power itself. PURPA's directive that the rates paid shall not exceed the purchasing utility's avoided cost is intended to protect utility customers from bearing higher costs as a result of the utility's QF power purchases. It follows from these two principles that the best reference points for determining the useful life of a CT to be used in setting avoided cost rates are: 1) the actual operating lives of the utility's CT fleet; and 2) the CT useful life assumptions used in setting the utility's base rates. The actual operating lives of a utility's CTs are relevant in assessing the capacity cost assumed to be avoided by purchasing from a QF. The useful life assumptions used for ratemaking measures the avoided costs from the customers' perspective. In this case, both the actual operating lives of the Utilities' CT and the useful life assumptions used for setting the Utilities' rates support the use of a 35-year useful life in setting the Utilities' avoided cost rates.

First, the vast majority of the CTs on the Utilities' systems have operated or are expected to operate for 35 years or more. In other words, the Utilities' combined experience with building and operating dozens of CTs over four decades conclusively demonstrates that CTs have useful life expectancies well in excess of 30 years. If anything, the Utilities' actual experience could support a longer useful CT life than 35 years. It should be noted that both

DEC and DEP are using a 35-year useful life for CTs in developing their 2013 IRPs.

Second, as to the useful life assumptions applied in the Utilities' most recent rate cases, each of the Utilities independently completed updated depreciation studies in support of their proposed depreciation rates. DEP's most recent depreciation study uses a 40-year useful life for its CTs. In DEC's most recent depreciation study, the lifespan of a new CT was considered to be 35 to 40 years with an emphasis on 35 years based on utilization. Thus, in terms of how long a CT should be expected to operate ***and*** in terms of the cost customers bear for a CT in rate base, the Utilities could justify a useful life in the range of 35 to 40 years in setting avoided cost rates. In jointly selecting 35 years (which is at the low end of that range), the Utilities have again used a reasonable assumption in developing their avoided cost rates.

IV. PERFORMANCE ADJUSTMENT FACTOR FOR SOLAR AND WIND QFS

Q. WHAT IS THE PERFORMANCE ADJUSTMENT FACTOR AND HOW DOES IT WORK?

A. The Performance Adjustment Factor ("PAF") is a multiplier that is applied to the avoided capacity rates paid by the Utilities to QFs based upon the Utilities use of the peaker methodology to determine their avoided cost rates. Currently, the PAF applied to the avoided capacity rates for small hydro-electric QFs with no storage capacity is 2.0 and the PAF applied to the

Utilities' avoided capacity rates for all other QFs is 1.2. So, for example, if the avoided capacity rate is $0.05/kwh, applying a PAF of 2.0 would increase the rate to $0.10/kwh, doubling the amount paid to the QF for capacity.

Importantly, under the Utilities' avoided cost rate structures, QFs receive both an avoided energy payment and an avoided capacity payment. This reflects the assumption that purchasing power from a QF allows the Utilities to avoid both the variable cost of producing power (i.e., the energy costs) and the fixed cost of building power generation facilities (i.e., capacity costs). However, the capacity value of a QF purchase is necessarily dependent on the QF's ability to provide power during on peak periods.

Q. **CAN YOU ELABORATE ON HOW THE AVOIDED CAPACITY PAYMENT IS DESIGNED TO WORK?**

A. To illustrate, assume a utility projected a need to meet an additional 100 MWs of peak load. The utility could build 100 MWs of generating capacity to meet that need or it could purchase 100 MWs of capacity from others. However, in order for such a purchase to allow the utility to "avoid" the cost of building this capacity, the purchase has to be fully available during peak periods. If, for example, the utility purchased 100 MWs of generation that was only available during the middle of the night, the purchase would do nothing to serve the utility's peak load and the utility would still have to build the 100 MWs of capacity needed to serve the growth in its peak load. Simply stated, purchasing power from a QF only allows a utility to avoid a capacity need if and to the extent that the QF can provide power during on-peak periods.

Accordingly, QFs receive avoided capacity payments only for power provided during on-peak periods. This arrangement allows QFs that operate during on-peak periods to receive full credit for the capacity that they are providing. Conversely, a QF that cannot provide power during on-peak periods receives only energy payments, which properly reflects the fact that such QFs provide no capacity value.

Q. **WHY DO HYDROELECTRIC QFS RECEIVE A PAF OF 2.0, AS OPPOSED TO THE PAF OF 1.2 APPLIED TO OTHER QFS?**

A. My understanding is that the Commission concluded that a larger PAF was justifiable for small hydroelectric QFs because the North Carolina General Assembly had enacted a policy generally supporting the continued operation of the State's small hydroelectric facilities. The Commission concluded that such a policy provided a basis for giving small hydroelectric QFs an even greater subsidy than other QFs, including solar and wind QFs.

Q. **ARE THE UTILITIES CHALLENGING THE USE OF A 1.2 PAF FOR SOLAR AND WIND QFS AND A PAF OF 2.0 FOR SMALL HYDRO QFS IN THIS PROCEEDING?**

A. No, not in this proceeding. For purposes of the rates proposed by the Utilities in this proceeding, the Utilities are not challenging the Commission's long standing practice of allowing QFs the benefit of increased capacity payments through the application of a 1.2 PAF. However, the Utilities believe that the current policy on PAFs raises questions under PURPA and reserve the right to challenge that policy in future proceedings.

It should be noted that in many past proceedings DEC has presented evidence that the current level of PAFs are excessive and provide unwarranted windfalls to intermittent QFs. As DEC pointed out in previous avoided cost proceedings, in order for a QF to receive full capacity credit, the QF should operate with a comparable level of consistency and reliability as the capacity that it is supposedly allowing a utility to avoid. Thus, if a conventional CT is available 95% of the time during peak periods, a QF operating at a comparable rate during peak periods should be entitled to full capacity credit. In order to account for the fact that even the facilities that QFs are allowing a utility to avoid are not available 100% of the time, a PAF in the range of 1.05 could be justified. This would allow QFs that operate as reliably during peak periods as CTs a fair opportunity to receive full capacity credit even if they are subject to the occasional outages common to all types of generating facilities. Thus, the Utilities believe that the current PAFs require customers to bear the burden of capacity payments to these QFs that exceed the value of the capacity they provide.

Q. WHAT IS YOUR UNDERSTANDING OF THE POSITION OF THE OTHER PARTIES IN THIS CASE REGARDING THE PAF FOR SOLAR AND WIND QFS?

A. Based on my reading of the comments filed in this docket, my understanding is that REG wants the Commission to increase the PAF for solar and wind QFs from 1.2 to 2.0. Not surprisingly, NCSEA supports REG's proposed increase in the PAF for wind and solar. Finally, it appears that the Public

Staff believes REG's proposal to increase the PAF for solar QFs is worthy of consideration.

Q. HAVE THESE PARTIES PROVIDED COMPELLING JUSTIFICATION FOR INCREASING THE PAF FOR SOLAR AND WIND QFS FROM 1.2 TO 2.0?

A. No, not in my opinion. REG offered the following four justifications in support of increasing the PAF for solar and wind QFs: 1) the inability of solar and wind QFs to operate consistently and reliably during on-peak hours; 2) the increased PAF will somehow place solar and wind QFs on par with similar facilities built by the Utilities; 3) small hydroelectric QFs already receive a PAF of 2.0; and 4) Senate Bill 3 represents a state policy in favor of encouraging renewable resources. As previously addressed in Section IX of the Utilities Joint Reply Comments, DEC and DEP do not believe that any of the foregoing rationales actually support increasing the PAF subsidy to these facilities. I will discuss the first three of REG's justifications below. Ms. Bowman addresses REG's assertion that Senate Bill 3 supports an increased PAF in her testimony.

Q. IS THE INABILITY OF SOLAR AND WIND QFS TO OPERATE RELIABLY AND PREDICTABLY DURING ON-PEAK HOURS A LEGITIMATE REASON TO GRANT SOLAR AND WIND QFS A 2.0 PAF?

A. No, it is not. REG argues that because solar and wind QFs have no control over their energy sources and no storage capability that they should, in effect, receive double the rate for the capacity they are able to deliver during peak periods. Stated another way, REG posits that because solar and wind QFs are unable to operate reliably throughout the Utilities' daily peak periods, these QFs should be granted higher capacity rates so that they can receive capacity payments that are in line with the capacity payments that more reliable QFs receive. There are several serious flaws in REG's argument.

First, REG proceeds from the false premise that PURPA is designed to ensure that all QFs receive equivalent capacity payments irrespective of reliability or availability. Based on that faulty assumption, REG reasons that if a QF cannot operate often enough to receive the maximum amount of capacity payments, the capacity rates it receives should be increased to make up for the QFs operational shortcomings. That approach contradicts both the letter and intent of PURPA that a QF should be paid an amount commensurate with the costs that it actually allows a utility to avoid. It follows that capacity payments to a QF can only be justified if, and to the extent, a QF can operate during peak periods. Unquestionably, a 5 MW QF that can operate only 20-40% of the peak period provides less capacity value than a 5 MW QF that operates 90% of the peak period and the more reliable QF should receive more in capacity payments. To inflate capacity payments to a less reliable QF – merely because it is less reliable – only serves to force the utility to pay the QF more than the capacity value it receives to the detriment of the Utility's ratepayers.

Second, as REG concedes, solar and wind QFs are limited because they cannot control when the sun shines or when the wind blows and, thus, cannot control when they operate. As a result, not only are solar and wind QFs unlikely to run throughout the on-peak hours, they cannot predict during which hours they will operate. This lack of predictability and reliability further diminishes the capacity value of solar and wind generation. For that reason, the Utilities do not count the full amount of solar or wind capacity in their generation portfolios in calculating their capacity reserve margins. Instead, the Utilities recognize that solar facilities are intermittent in their nature. In fact, even on clear, summer days when solar generation runs, the output of solar facilities declines after 1 p.m. as utilities are ramping up to meet their late afternoon peak, which occurs at approximately 5 p.m. Accordingly, DEC and DEP only count 40% of the rated capacity of solar facilities in determining their system reserves. Stated another way, only 40% of a solar facility's rated capacity reliably provides reductions to a utility's future generation needs. The same general concepts hold true for wind resources with the exception that wind generally provides even less of its rated capacity during times of peak. In fact, the Utilities use only approximately 15% of a wind resources rated capacity when calculating the amount of traditional generation that can be avoided by a wind resource. The proposal to increase the PAF for solar and wind QFs ignores these operational limitations of solar and wind technologies.

Third, the entire underpinning of REG's argument is suspect. When stripped to its basics, REG's position is that the Commission should increase the capacity rates paid to solar and wind QFs to make up for their inherent operational limitations. This is far different than using the PAF as means to account for the occasional outages that all types of generation experience. Rather, this is an artificial increase in the rates paid to certain types of facilities to make up for the fact that they can only operate in a limited and unreliable fashion during peak periods, when utilities most need reliable capacity. Notably, REG presents no explanation or supporting evidence of why a 2.0 PAF is appropriate, as compared to a 1.7 PAF or 3.2 PAF. Thus, if REG's request is accepted, the logical extension of it would be that the worse a QF operates during peak times, the higher the PAF should be for that QF to make up for its operational deficiencies. Viewed in that light, REG's request for a 2.0 PAF for solar and wind QFs can be seen for what it is – an unwarranted windfall that has to be funded and borne entirely by the Utilities' customers.

The Utilities wish to make clear that their strong opposition to REG's PAF recommendation is not opposition to solar or wind technology or the Commission's historical encouragement of QFs in compliance with FERC's directive to provide them the Utilities' full avoided costs. Instead, our opposition is based on the recognition that PURPA was not intended – and does not allow – QFs to receive rates in excess of the Utilities' avoided costs.

Q. WHY DOES THE UTILITIES' ABILITY TO RECOVER THE COST OF INSTALLING THEIR OWN SOLAR AND WIND RESOURCES FAIL TO JUSTIFY AN INCREASE IN THE PAF FOR SOLAR AND WIND QFS?

A. Regulated utilities and independent QFs are subject to completely different regimes and regulations with respect to ratemaking and cost recovery. The argument that the Utilities recover the full capacity cost while the QF recovers only a portion of its capacity cost is simply not true, nor is it a valid comparison.

As discussed at length previously in my testimony, the Utilities use the peaker methodology for the purpose of setting avoided cost rates offered by DEC and DEP. Under this method, a QF receives avoided capacity payments based on the capital cost of a hypothetical new CT. Significantly, the payments that a QF receives have nothing to do with the cost it incurs to build its facility. As a result, a QF facility is free to earn a return on its capital without limit or regulation under this rate structure. Conversely, a utility is entitled only to charge rates set by the Commission, which are designed to allow the utility the opportunity to earn a Commission-established return on its invested capital.

To further illustrate this difference between ratemaking for a utility and avoided cost rates, consider the case of a utility building a solar facility. The utility would be allowed to charge its customers very little for fuel and operating expenses for such a solar facility because solar generation requires no fuel and has minimal operating expenses. The small amount that a utility could recover for operating expenses associated with a solar facility would be designed to allow the utility to only recover its expenses. Under the peaker methodology, a solar QF receives energy payments based on the purchasing utility's marginal cost of energy, which far exceeds the QF's operational expenses.

The foregoing highlights the conceptual and practical differences between traditional ratemaking and avoided cost rates. It shows that these two rate setting systems are so dissimilar that they cannot be compared directly and certainly indicates that a utility's opportunity to earn a Commission-fixed return does not justify raising the PAF for solar and wind QFs to 2.0. If anything, the empirical evidence suggests that the current avoided cost rate framework is more than sufficient to provide solar and wind QFs with the same thing that traditional ratemaking provides a utility – an opportunity to earn a fair return on investment. North Carolina is currently experiencing historic levels of QF interest, particularly from developers of solar QFs. Presumably, these developers have concluded that the State's current avoided cost structure, which applies a PAF of 1.2 to solar and wind QFs, provides them with an adequate opportunity to earn a reasonable return on their investment. From that perspective, QFs are already at least on par with the Utilities in terms of cost recovery and no further increase of the PAF is needed or warranted.

Q. **WHY DO THE UTILITIES BELIEVE THAT THE CURRENT USE OF A 2.0 PAF FOR SMALL HYDROELECTRIC QFS FAILS TO SUPPORT USING A 2.0 PAF FOR SOLAR AND WIND QFS?**

A. As previously discussed, the Commission has allowed a higher PAF for small hydroelectric QFs, but as I stated previously, the Commission did so taking into account the State's historical policy of supporting the operation of these types of facilities. In adopting this policy, the Commission was able to provide support to those facilities without imposing a significant burden on consumers. Only a limited amount of run-of-river hydroelectric generation is possible in North Carolina, which effectively caps the potential impact to customers of increasing the avoided capacity payments made to small hydro-electric QFs. The same cannot be said of other intermittent facilities, particularly solar facilities.

Q. **PLEASE SUMMARIZE YOUR CONCLUSIONS AS TO THE SUGGESTION THAT THE PAF FOR SOLAR AND WIND QFS SHOULD BE INCREASED TO 2.0?**

A. The policy of providing a PAF of 2.0 for small hydroelectric QFs and a PAF of 1.2 for solar and wind QFs has been in place in North Carolina for many years, and as stated above, the Utilities are not challenging that policy here. Nevertheless, the Utilities firmly believe that raising the PAF for solar and wind QFs to 2.0 is unjustified and inconsistent with the concept that rates paid to QFs should not exceed the cost that a utility avoids by purchasing power from such QFs. The Utilities, therefore, urge the Commission to reject the request to increase the PAF for solar and wind QFs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MR. SOMERS: And I would note for the record and for the court reporter's benefit that Mr. Snider's direct testimony contains confidential information at page 20 through 22 and pages 31 through 34, and we would ask that it be marked as such in the Commission's record and treated as confidential.

BY MR. SOMERS:

Q Mr. Snider, have you prepared a statement in support of the settlement that has already been accepted into the record by the Commission?

A I have.

Q And as I was noting earlier on the record, there is a confidential number in there. I would ask that you please read your settlement statement but not read that confidential number.

A Certainly. (Summary read into the record.)

DUKE ENERGY PROGRESS, INC.

DUKE ENERGY CAROLINAS, LLC.

DOCKET NO. E-100, SUB 136

GLEN SNIDER'S SETTLEMENT SUPPORT STATEMENT

The purpose of my summary is to support the Stipulation Agreement entered into among Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), the Public Staff, and Renewable Energy Group and to provide a brief overview of the settlement of installed CT costs contained in the Stipulation. Pursuant to the Stipulation, DEC and DEP will both use **[Begin Confidential]** **[End Confidential]** as the installed CT cost in calculating their respective avoided cost rates. The Utilities believe 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. As with the other components of the Stipulation discussed previously by Ms. Bowman, the Utilities ask that the Commission approve the Stipulation in its entirety.

This concludes my statement.

Q. And Mr. Snider, since the time that this statement was copied, did North Carolina Sustainable Energy Association also join in the stipulation as to the CT costs?

A They did, and I would add that to my statement.

Q Thank you. Have you also prepared a summary of your direct testimony?

A I have.

Q Would you please give that to the Commission?

A The purpose of my testimony is to support the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc.'s ("DEP") (collectively, the "Utilities" or the "Companies") proposed avoided cost rates. I discuss the collaborative effort between DEC and DEP after the merger which resulted in changes in certain aspects of how they calculated their avoided cost rates, improving the Utilities' avoided cost processes and resulting in better supported and more appropriate avoided cost rates. This cooperation between the Utilities was one of the significant benefits envisioned by the merger. Contrary to the suggestions by some parties, it resulted in several decisions that actually increased the Utilities' proposed avoided cost rates. However, in comparison to past rate filings, the

Utilities' avoided cost rates generally have declined due to declining natural gas prices and declining cost per kW of simple cycle turbines.

My testimony also discusses the installed CT costs used by the Utilities in developing their respective avoided cost rates as well as in their 2012 IRPs. These costs were based on independent cost studies commissioned separately by DEP and DEC from two leading engineering firms. In addition, after the Utilities filed their avoided cost rates in this docket, the Utilities sought out a third independent source of information for additional validation The Utilities engaged Black and Veatch to conduct this independent estimate of the cost to construct a four-unit simple cycle facility in North Carolina. Those results are presented independently in the testimony of Theodore Pintcke, Vice President of Project Development for Black and Veatch.

As a result of the post-merger collaboration, the installed CT cost used in calculating DEP's avoided cost rates is higher than the value used in DEP's 2012 IRP, but the installed CT costs that DEC used to calculate its proposed avoided cost [sic] rates were substantially lower than the CT costs it used in developing DEC's 2012 IRP. That difference does not indicate any flaw or error in the development of DEC's avoided capacity rates, but instead, represents reasonable common assumptions regarding such items as useful life and level of contingency. DEC and DEP have direct experience in constructing and operating CTs, and the contingency adder and useful life used by the Utilities directly reflect that actual experience.

I also discuss REG's proposal that the PAF of solar and wind QFs increase from 1.2 to 2.0. REG argues that because solar and wind QFs have no control over their energy sources and no storage capability, they should, in effect, receive double the capacity rate for the capacity they are able to deliver during peak periods. The Utilities' strong opposition to REG's PAF recommendation is not in opposition to solar or wind technology nor the Commission's historical encouragement of QFs in compliance with FERC's directive to provide them the Utilities' full avoided costs. Its opposition is based on the recognition that PURPA was not intended -- and does not allow -- QFs to receive rates in excess of the Utilities' avoided costs. The Utilities urge the Commission to reject the request for an increase in the PAF for solar and wind QFs.

This concludes the summary of my direct testimony.

Q **Thank you, Mr. Snider.**

MR. SOMERS: Madam Chair, at this time based upon the settlement of the parties, Mr. Snider is available for cross-examination.

COMMISSIONER BROWN-BLAND: All right. Do we have cross-examination of this witness? Mr. Youth.

CROSS EXAMINATION BY MR. YOUTH:

Q **Good afternoon, Mr. Snider.**

A Good afternoon, Mr. Youth.

Q **In the summary you just read, I believe it says "its opposition." This is on line 14 of page 2. Does that "its" refer to the plural utilities --**

A Yes, it does.

Q **-- in the previous sentence? So is it fair to say the Utilities' opposition to an increased PAF is based on a recognition that PURPA was not intended and does not allow QFs to receive rates in excess of the Utilities' avoided costs?**

A That is correct.

Q **And so would you agree that the Utilities' opposition to an increased PAF is based upon an assumption that an increased PAF results in payments to**

QFs that are in excess of the Utilities' avoided costs?

A Yes. It's based on the assumption that if you increase the PAF you would have a rate that would result in a cost that is more than is actually avoided but for that QF coming into fruition.

Q And if that is an incorrect assumption, the Utilities' opposition could -- the Utilities would have to re-evaluate their opposition; is that correct?

MR. SOMERS: Objection. Assumes facts not in evidence.

MR. YOUTH: I'm unclear which facts I'm asking be assumed into evidence. If --

MR. SOMERS: That's my objection.

COMMISSIONER BROWN-BLAND: Rephrase the question or move on.

BY MR. YOUTH:

Q The Utilities' opposition is based on an assumption -- and I'm going to be very pointed -- that a 2.0 PAF for solar would result in payments to solar QFs that is in excess of the Utilities' avoided costs. I think we've established that, correct?

A Yes, we have.

Q And I'm asking you if that assumption is incorrect, fundamentally incorrect, that it does not

result in payments in excess of avoided costs, would that cause you, Mr. Snider, to re-evaluate your opposition to an increased PAF?

A If, after applying a 2.0 PAF, it could be demonstrated that the resulting rates paid to the solar provider or any QF provider were justified based on the costs the Utilities would, but for that facility, have otherwise avoided -- so after the allocation of the PAF, the resulting dollars equated to the cost that could truly be avoided, then we would yes, rethink.

Q So that was a long answer; it's late in the day. Long answer for me. Is it correct, then, that if the assumption is bad it would merit re-evaluation? And I'm not presupposing what the outcome would be. You indicated the outcome might -- I changed it to --

A If the assumption was bad, then the assumption would be not in the PAF but more in the hours or what was ascribed to, as you pointed out, the size of your spoon. I never really have thought that the PAF should be used in the manner that's being proposed. So I wouldn't readdress the PAF; I would probably address the other factors that went into that capacity payment. I'm not supporting a 2.0 PAF even if that assumption was -- was bad.

MR. YOUTH: Commissioner Brown-Bland, I would ask that what I've handed to the witness and up to the Commissioners be marked for identification as NCSEA Public Snider Cross Exhibit Number 1.

COMMISSIONER BROWN-BLAND: Let it be so identified.

(Whereupon, NCSEA Public Snider Cross-Examination Exhibit 1 was marked for identification.)

BY MR. YOUTH:

Q **Mr. Snider, I'd like to ask you a few questions about natural gas hedging costs. If you take a look at pages 1 and 2 of the exhibit, the cross exhibit, these are Progress and Duke responses to NCSEA data requests, correct?**

A Yes, they are.

Q **And on page 1, Progress states that it has not included natural gas hedging costs into its proposed rates; is that correct?**

A That is correct.

Q **And on page 2, does it indicate that Duke did not factor any natural gas hedging costs into the proposed rates also?**

A That is correct.

Q Now, I'll ask you to flip through pages 3 through 22 of the cross exhibit. These pages contain the recent sworn testimony of Sasha Weintraub on behalf of Duke Energy Progress in its 2013 fuel rider proceeding together with a cross exhibit that he refers to in that testimony. Subject to check, is that correct?

A That appears to be correct, subject to check.

Q If you turn to page 11 of the cross exhibit at transcript line 11, Mr. Weintraub was asked if he would look at page 3 of an exhibit, and he was asked if the blue line on the exhibit represented in round numbers the additional cost to Progress' rate payers associated with Progress' financial hedging for each of the last few test periods; is that correct?

A Subject to check.

Q And he responded yes; is that correct?

A Yes, he did.

Q So now I'll ask you to turn to page 21 of the cross exhibit. And you'll note the number 3 right above the page number 21. Subject to check, would you agree that this was the graph Mr. Weintraub was looking at?

A Subject to check.

Q And it shows that the additional cost to rate payers for Progress' financial hedging was roughly 39 million in the 2010 test period; $51 million in the 2011 test period; and $70 million in the 2012 test period, correct?

A That is correct.

Q Now, if you'll turn back to page 14 of the cross exhibit? And I'm now looking at lines 15 forward. Mr. Weintraub did say at the hearing that he expects hedging losses to be coming down, but he conceded that it wasn't going to go from $70 million to zero immediately, correct?

A I believe that's correct, what he says on this page.

Q He states at the bottom of page 14 of the cross exhibit, "I would expect by 2014 you should start seeing this come back down. I'm sorry, 2014 and 2015 you should start seeing this come back down to that zero." Is that correct?

A Correct.

Q So he doesn't say it will be zero in 2014 or 2015; he says it should start heading towards zero, correct?

A Correct.

Q And that is the expectation. But these are natural gas prices we're talking about, and there are no guarantees, correct?

A That is correct.

Q Except to say it's probably a pretty good bet that Progress' customers will continue to bear some hedging losses in the next two years at least, correct?

A That is correct.

Q Now, Duke has not entered into financial hedges to this point, correct?

A I am not aware whether they have or not. I've just stipulated to what Mr. Weintraub has said.

Q And let me be clear. This is Duke Energy Carolinas I'm talking about.

A Subject to check.

Q If you turn to page 24 of the cross exhibit? Maybe if you turn to page 23 first. If you agree, subject to check, that pages 23 and 24 of the cross exhibit are an excerpt from this Commission's order approving fuel charge adjustment in Docket E-7, Sub 1033?

A I accept that.

Q And if you turn to page 24 of the cross exhibit at the arrow, in response to Duke Energy Carolinas' increasing consumption of natural gas, the Commission has ordered Duke Energy Carolinas to file a natural gas hedging strategy by the end of the year; is that correct?

MR. SOMERS: Objection. Misstates the document.

COMMISSIONER BROWN-BLAND: Excuse me, Mr. Somers. Repeat, please?

MR. SOMERS: That's not what it says.

BY MR. YOUTH:

Q **Mr. Snider, would you read paragraph 4 on page 24 of the cross exhibit?**

A "The Duke Energy Carolinas shall file an updated fuel procurement practices report in Docket E?100, Sub 147 that includes a natural gas hedging strategy no later than December 31, 2013."

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: All right. Is there further cross examination? Ms. Mitchell?

CROSS EXAMINATION BY MS. MITCHELL:

Q **Good afternoon, Mr. Snider. Charlotte Mitchell on behalf of the Renewable Energy Group.**

A Good afternoon, Ms. Mitchell.

Q **Just a few questions for you. Mr. Snider, is it the Company's position that an Option B approach such as the one agreed to by the Company in the settlement with the Public Staff is a reasonable compromise of the parties' respective positions in the docket?**

A It is.

Q Were you in the room at the beginning of this hearing when Commissioner Brown-Bland called us to order and counsel for the parties were taking care of preliminary matters and counsel for Dominion indicated to the Commission that the Renewable Energy Group has joined the Public Staff's settlement with Dominion which includes an Option B?

A I was in the room. I don't recall that. I'm sorry.

MS. MITCHELL: Okay. No further questions.

COMMISSIONER BROWN-BLAND: Ms. Ottenweller?

MS. OTTENWELLER: Thank you.

CROSS EXAMINATION BY MS. OTTENWELLER:

Q Good afternoon, Mr. Snider.

A Good afternoon.

Q I want to pick up where I left off with Ms. Bowman discussing -- do you remember the hypothetical that I posed for her?

A I do.

Q Okay, great. So we got to the point where she stated that even for a store with several megawatts of solar on its roof, most of the power would be consumed at or near the distributed generation source. Do you

remember that?

A I believe I remember her saying it, yes.

Q Okay. So my question for you is neither utility includes distribution line losses in its calculation of avoided costs, correct?

A Correct.

Q So if most of the power is being consumed near the distributed generation source, can you explain why neither utility includes distribution line losses in its avoided costs?

A I'll do my best. We're not talking about in this proceeding rooftop solar behind the meter. We're talking 5 megawatts and under that can be connected to either the distribution or the transmission system. You are not in this proceeding asking for even solar. It's not a solar array; it's a QF array hooked up to the distribution system.

So if you are to put a QF generator on your distribution system, that QF generation still has to flow to the load somewhere on that system and so that it's still incurring those distribution losses to move -- if I put a 400 or 4 megawatt QF facility on that distribution circuit, it's got to flow over that distribution circuit to serve the businesses and homes in that circuit. And so it still incurs a distribution line loss, but it is credited for not going onto the transmission system, which in some cases it can but we ignore that for the -- you know, for the benefit of the QF in this proceeding and just assume it stays consumed on the distribution circuit.

Q So your testimony is that the situation that I posed in this hypothetical, that type of facility would have all of the distribution line losses that other non-solar facilities would have? It seems like that was what you just said. I just wanted to clarify.

A Depending on where it is. Again, it's not -- it's not location specific. But yes, I'm saying it would incur distribution line losses.

Q Okay. Just to make sure I understand what you're saying, it would incur all of the distribution line losses that are being currently attributed to it in the Company's avoided cost rates.

A I believe the Company's avoided cost distribution rates reflect what losses would be incurred. I -- I don't -- I'm not the -- I don't have the study in front of me or the details behind it. But yes, I think what we proposed are -- are based on what those line loss rates are and what would be incurred by a distribution connected QF facility.

Q Okay?

MS. OTTENWELLER: Madam Chair, may we approach the witness with an exhibit?

COMMISSIONER BROWN-BLAND: Yes.

MS. OTTENWELLER: Okay. Thank you.

COMMISSIONER BROWN-BLAND: Madam Chair, I would ask that these two exhibits that I am handing out would be marked for identification as SACE Snider Cross-Examination Exhibits 1 and 2 with the supplement that's being handed out now being Exhibit 2.

COMMISSIONER BROWN-BLAND: Okay. The two-page exhibit --

MS. OTTENWELLER: That would be Exhibit 1.

COMMISSIONER BROWN-BLAND: -- will be marked as SACE --

MS. OTTENWELLER: SACE Snider Cross-Examination Exhibit Number 1.

COMMISSIONER BROWN-BLAND: Let it be so identified. And the supplemental response, which is one page, will be identified as SACE Snider Cross-Examination Exhibit 2.

(Whereupon, SACE Snider Cross-Examination Exhibits 1 and 2 were marked for identification.)

MS. OTTENWELLER: Thank you.

BY MS. OTTENWELLER:

Q Mr. Snider, does this appear to be a response and a supplemental response provided by DEC and DEP to a data request by SACE?

A Yes, it does.

Q And would you accept, subject to check, that that's what it is?

A Yes, I would.

Q Okay. Thank you. DEC and DEP's avoided cost rates incorporate transmission line loss rates, and DEC also identified a small additional credit related to transmission interconnection; is that right?

A Can you point me to that, please?

Q The transmission interconnection credit? I believe that it's in the Company schedules. But subject to check?

A Subject to check.

Q Okay. If you could refer to the supplemental exhibit that I handed out, Exhibit 2, question 1(c)? I'm going to ask you some questions about the Utilities' response to that question. Duke transmission line loss rates are assigned for on-peak and off-peak hours, correct?

A They are.

Q And here Duke agrees that line losses vary not only by load or demand but also based on operating conditions?

A They do.

Q And operating conditions could include changes in temperature or weather patterns?

A I believe they can.

Q Okay. Would you agree that a utility's distribution line losses are generally larger than its transmission line losses?

A I would agree.

Q And not only are they larger, but the variation from hour to hour across the year would be greater for distribution line losses than transmission line losses?

A I'm sorry. I'm not -- I don't know that information.

Q Okay. That's fine. Has Duke done any studies -- and by Duke I mean DEP or -- yeah, thank you -- done any studies to determine if solar power in particular would benefit from a load weighted estimate of distribution and transmission line losses?

A Not to my knowledge.

Q Okay.

MS. OTTENWELLER: Thank you. No further questions.

COMMISSIONER BROWN-BLAND: Okay. Mr. Dodge, I take it you have none?

MR. DODGE: No questions.

COMMISSIONER BROWN-BLAND: Is there redirect?

MR. SOMERS: Yes. Thank you, Madam Chair.

REDIRECT EXAMINATION BY MR. SOMERS:

Q Mr. Snider, you were asked some questions by Mr. Youth about gas hedging practices, or more specifically about what Duke Energy Carolinas witness Weintraub testified to in this year's fuel proceeding. Do you recall that line of questioning?

A I do.

Q Let me ask you something relevant to avoided costs. Were hedging costs included in the Company's proposed avoided cost rates in this proceeding?

A They were not.

Q Why not?

A Hedging costs, first of all, are -- are some costs. You're looking at incrementally what's happening. So hedging costs -- we only hedge, as I understand the hedging program, a very small percent of our natural guess. When you look at what's happening on the margin, none of that gas is hedged. Furthermore, what hedging does is it locks in costs two or three years out based on what the costs are expected to be. A gain or loss as described by Mr. Weintraub is relative to what happened when you get to that period.

The QF rates are very much developed in the same way so the same things that produced the hedging losses were also producing QF rates that were higher based on an expectation of those very same gas prices that when you got there, those prices never materialized. So the equivalent of a hedging loss would be a QF loss.

All the QFs we signed up in the same period we were signing up those gas hedges would also be being paid today based on the expectation that gas had rose instead of dropped. So the same thing that created a hedging loss created a QF loss. And we don't include either of those in the calculation of our rate.

MR. SOMERS: Thank you. No further questions.

COMMISSIONER BROWN-BLAND: Is there any cross-examination on the confidential material?

(No response.)

COMMISSIONER BROWN-BLAND: I don't see that there is any. Is there questions from the Commission?

I'll call on Commissioner Rabon.

EXAMINATION BY COMMISSIONER RABON:

Q Good afternoon, Mr. Snider.

A Good afternoon.

Q You were in the room when I was asking my question of Ms. Bowman a little earlier, correct?

A I was.

Q Okay. Do you have any information for us on -- in your experience how much of what is put in the queue actually comes online?

A It's difficult to project that only in that this queue has risen so fast. I mean just a couple of years go we only had 30 or 40 megawatts in the queue compared to a couple of thousand. It's my understanding that of the -- the few hundred that came on last year, we already have 100 in service so we are seeing a -- an amount of them coming into fruition. My professional expertise would say that as an estimate somewhere 50 percent plus or minus. But again, with a very big band around that number depending on the circumstances.

Q Okay. So does the Company have any numbers on those figures that you're aware of?

A We have some numbers that I could submit as a late-filed exhibit that show exactly how much has come to fruition to date --

Q **That would be -- that would be nice.**

A -- and -- and give you some more information on that.

A Okay.

COMMISSIONER RABON: Thank you very much.

COMMISSIONER BROWN-BLAND: Chairman Finley.

EXAMINATION BY CHAIRMAN FINLEY:

Q **Mr. Snider, can you tell me since 2007 how many contracts either DEC or PEC have entered into with new hydro facilities to purchase the electric output from those facilities?**

A To my knowledge, I don't know of any. But I would have to say that subject to check, Chairman Finley.

Q **Do you know whether or not there have been hydro owners that at one point you acquired the electric generation from those facilities and you have discontinued purchasing that output?**

A I'm not familiar with that piece of information. I apologize.

Q **Okay. To one extent, environmental groups are in favor of hydroelectric facilities because of no emissions, right?**

A Correct.

Q But then again, there are other environmental groups that disfavor using hydroelectric facilities to generate power, fish and wildlife people for example; is that right?

A That has been my experience?

Q Are you familiar with efforts that have been undertaken, for example, to take small obstructions out of streams because of the concern for the fish and wildlife?

A Yes, I have heard of those.

Q All right. And I guess with respect to solar generated power again you have some environmental groups that are not in favor of wind generation because of the birds and bats and that type of thing?

A Correct.

Q What about for solar? Is there any -- are you aware of any environmental groups that are worried about the effects of solar on the environment or other environmental concerns?

A The only concern I have seen raised in -- in just general reading has been about the -- the amount of land that is -- that is consumed to -- to put up large-scale solar facilities.

Q And you see some adjoining landowners concerned

about the impact that that would have on their property values and that type?

A Yes. That's what I was referring to.

CHAIRMAN FINLEY: All right. That's all I have. Thanks.

COMMISSIONER BROWN-BLAND: Mr. Snider, I have one for you.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Does DEC now contend that the 2.0 PAF for hydro violates PURPA because it allows for excess payments or payments in excess of avoided costs?

A Commissioner, it's my understanding that the small hydro was done before Senate Bill 3 in the absence of any incentives and with legislation at the time that -- that directed the state to encourage that. I -- I don't have an opinion. We're supporting the maintain -- in this proceeding we're supporting maintaining the 2.0, but I -- I don't want to --

Q But you don't know whether or not the Company views it as a violation of PURPA?

A I don't know.

Q Okay.

COMMISSIONER BROWN-BLAND: I would call on Commissioner Beatty.

EXAMINATION BY COMMISSIONER BEATTY:

Q My question may be confidential. If you can answer it -- did you hear the question I asked Ms. Bowman when we cleared the room earlier?

A Yes.

Q Are you able -- without answering just that question, but would you be able to expound on her answer any if I were to ask you that question?

A I can expound on, I think, what has been said to publicly, which is the stipulation represents about an 8 percent increase before the application of the PAF for the DEC capacity rate and about a 14 percent increase in the capacity rate for the -- as filed for DEP. If you look at the range of issues that parties to this proceeding had filed with respect to whether it was contingency, useful life, unit ratings, two -- two units versus four units, vintage of the data being used, et cetera, the range of those variables in their totality was in far greater excess than the 8 and 14 percent.

And so I would agree with Ms. Bowman that while the Utilities would have thought that that is definitely on the upper end, upper range that we thought was just and reasonable and would otherwise be avoided but for the QF, the parties to this may have thought that that was on the lower end. But we did find common ground on a number that we both thought was just and reasonable given that percentage change in the filed rates.

Q Would you be able to provide any more of an answer if it were confidential and we cleared the room?

A I might be able to give you when I spoke of those -- those individual variables some of the percentages that were being discussed and what the impact would have been variable by variable to -- to show you that in that totality, you know, we were looking at -- at numbers.

COMMISSIONER BEATTY: I think I'd like to get his full answer.

COMMISSIONER BROWN-BLAND: All right. Before we clear the room, is there any other -- Chairman has a non-confidential question.

CHAIRMAN FINLEY: Just one follow-up that I failed to ask Mr. --

EXAMINATION BY CHAIRMAN FINLEY:

Q Mr. Snider, are you familiar with the LaCapra study that was done preliminarily to the passage of Senate Bill 3?

A Loosely, yes. I remember that study had been done.

Q Do you have a recollection of what that study said about the projection of taking advantage of Senate Bill 3 to promote hydroelectric generation? Yeah, hydroelectric generation. Projections that were made about what Senate Bill 3 might --

A I'm sorry, Commissioner. I do not remember exactly with respect to hydro how much LaCapra had -- had forecasted to come online as a result of Senate Bill 3.

Q Do you know the extent to which those projections have been met since 2007, then?

A I would expect that they have not since we have not added hardly any hydro --

Q Okay.

A -- to our rate base.

COMMISSIONER BROWN-BLAND: Okay. Ladies and gentleman, some of you will get another chance for a little exercise. If you would -- if you've not signed onto the nondisclosure agreement, if you would please exit the room at this time.

Counsel for Duke, I will again call on you to let me now when the room is satisfactory.

(Pause.)

COMMISSIONER BROWN-BLAND: Ms. Fentress, are we in agreement on those who remain?

MR. SOMERS: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Oh, sorry, Mr. Somers. Okay. Commissioner Beatty.

(Because of the proprietary nature of the testimony contained on pages 261 to 263, it was filed under seal.)

(Testimony on the open record resumed.)

COMMISSIONER BROWN-BLAND: All right. Now, are there questions on Commission's questions, particularly those non-confidential portions that I neglected to ask about a moment ago?

MR. YOUTH: I will try to ask a few questions.

COMMISSIONER BROWN-BLAND: All right. Mr. Youth.

CROSS EXAMINATION BY MR. YOUTH:

Q Mr. Snider, I think in response to the question you indicated that the settled upon numbers increased the capacity rates that Duke and Progress are asking the Commission to approve at this point; is that correct?

A They are. Yes, that is correct.

Q And I -- I just want to clarify, if I can, if I'm understanding things correctly, while those settled upon rates indicate an increase from what was originally proposed November of last year, are those rates still lower than the 2010 approved rates?

A Yes, they are.

Q The next thing I'll ask, I think you were asked by Commissioner Rabon about the queue and how much comes online. Do you recall that line of questioning?

A I did.

Q And I think you indicated that your best estimate was around 50 percent.

A Let me say plus or minus 20.

Q What is or what are the Company's experience with projects that are seeking to move forward under the 2010 -- or excuse me, the 2012 proposed rates? Are you still seeing a 50 percent likelihood of moving from contract to installation plus or minus 20 percent or is that lower?

A I don't have that information directly in front of me. I can say we still have a lot of interest coming in with the 2012 filings; that I can tell you.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: Further questions on Commission's questions? Ms. Mitchell.

MS. MITCHELL: Just a few questions, Mr. Snider.

CROSS EXAMINATION BY MS. MITCHELL:

Q I'm just going to continue along the line that -- that Mr. Youth was asking you. With respect to the 50 percent number, I think I just heard you say 50 percent plus or minus 20; is that correct?

A Yeah, so a wide range of 30 to 70 percent. And

I'm hedging my bets intentionally. Really, clarifying my answer was this queue has grown rapidly since the tax incentives have come on -- into fruition and into play and Senate -- you couple that with Senate Bill 3. We've seen over just the last couple of years, you know, and really just in the last year a tremendous increase in our queue. So we don't have a long history to say how much of it will come to fruition. You now, we've had a much smaller amount in years preceding that.

Q **And for those projects in your queue, how -- how many -- for how many of those projects in your queue have you received a payment on the interconnection agreement?**

A I don't have that number in front of me.

Q **Okay. Would you be -- Mr. Snider, would you be willing to provide that information in a late-filed exhibit?**

WITNESS: (To Mr. Somers) Is that something we're allowed to provide?

MR. SOMERS: What's the basis for this request?

MS. MITCHELL: I'm just trying to determine how many of -- where these projects are that he's referencing that are in the interconnect queue.

MR. SOMERS: We've already agreed in response to Commissioner Rabon's request for a late-filed exhibit to prepare information on the number of projects that we've seen in the queue and the number have come to fruition and that's what we'll do.

MS. MITCHELL: And will that information -- will that information that you provide in response to Commissioner Rabon's request include those projects for which an interconnect payment has been received by the Company?

MR. SOMERS: If the Commission wants us to, we will.

COMMISSIONER BROWN-BLAND: Do you -- do you have further questions right now?

MS. MITCHELL: Just one more question. What information does the Company plan to provide in response to Commissioner Rabon's question?

MR. SOMERS: Well, I don't know that I wrote it down word for word, but we'll provide whatever she asked for; which again, I took to mean -- and please correct me if I'm wrong -- a list of how many projects have come to fruition to date. But I'm sure the transcript would explain specifically what she asked for, and that's what we'll do.

COMMISSIONER BROWN-BLAND: Let me intervene at the moment. Your response was would the Commission like to have that information on payment of the interconnections, and we would like you to include that in the late-filed exhibit, please.

MR. SOMERS: We'll be glad to.

MS. MITCHELL: Commissioner Brown-Bland, I have just one more question. And I'm sorry; I was actually -- I was looking at Duke's counsel when I asked the question, and I should have been looking at Mr. Snider because my question was directed at Mr. Snider as he's the one that indicated the 50 percent number based on his experience. I'm just curious as to what information Mr. Snider was -- was envisioning or -- or contemplating when he responded to the Commissioner's question.

A Again, we have limited experience with the current queue, and I was expanding upon that with my experience with commercial contracts in general, that you have many requests, whether it's QF power or whether it's traditional gas-fired generation, that expressed interest does not mean that it's fully going to come to fruition. And so I was just saying there's a broad range in -- and especially in the context of -- of this proceeding and the amount of -- the rapid growth. It's -- it's too early to predict, and that's why I gave such a large range.

Q **I understand. I understand your response to that question. My question was what information are you going to provide to the Commission to support that range.**

A I think my counsel just answered, which is what we're going to provide is -- and that was not the question that the Chair had asked. It was can you show us where you currently are with all of these customers in the queue. And so what we plan to provide is who's expressed interest and what stage of the process they're in. And I don't know what form or fact that exhibit will take yet.

MS. MITCHELL: Nothing further.

MS. OTTENWELLER: Just one question.

COMMISSIONER BROWN-BLAND: Ms. Ottenweller.

CROSS EXAMINATION BY MS. OTTENWELLER:

Q **Mr. Snider, have any of the environmental or clean energy groups that have intervened in this docket opposed hydro, solar, or wind projects that you're aware of?**

A Not the ones that have intervened in this group, no.

MS. OTTENWELLER: Okay. Thank you.

COMMISSIONER BROWN-BLAND: Further questions on

Commission's questions? Mr. Somers.

MR. SOMERS: I do. Thank you, Madam Chair.

REDIRECT EXAMINATION BY MR. SOMERS:

Q **Mr. Snider, you were asked a question by Commissioner Brown-Bland as to essentially whether the Companies contend that the 2.0 PAF violates PURPA. Do you recall a question along those lines?**

A Yes, I do.

Q **As I heard your answer, you testified that the Company -- your testimony was supportive of maintaining the 2.0?**

A Yes, it is.

Q **Is that what you meant to say?**

A The 2.0 for small hydro facilities as currently outlined in the -- in the last filing in this filing.

Q **And what is the Company's position as to the application of a 2.0 PAF for non-hydro QF facilities?**

A I think at this point in time, the Company's position is that is not consistent with PURPA and would be outside of the intent and the letter of PURPA.

Q **And you're not -- you're not a lawyer, are you?**

A No, but I did stay at the Holiday Inn Express.

Q **And you do have a boss who's been known to over -- or to object to objections of her counsel, aren't you?**

A Yes, I do.

Q But in all seriousness, the legal issues as to whether or not what the Companies view as to whether or not the PAF does or does not violate PURPA, is that a legal argument the Company will make in its post-hearing submissions?

A I believe it will.

Q Okay.

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

COMMISSIONER BROWN-BLAND: All right. There's no further questions at this time for this witness. I'll entertain your motions.

MS. OTTENWELLER: I would ask that SACE's Snider Cross-Examination Exhibits 1 and 2 be admitted at this time.

COMMISSIONER BROWN-BLAND: They will be admitted without objection.

(Whereupon, SACE Snider Cross-Examination Exhibits 1 and 2 were admitted into evidence.)

MR. YOUTH: I would ask that NCSEA's cross exhibits also be admitted.

COMMISSIONER BROWN-BLAND: Cross exhibit -- I believe that's one cross exhibit?

MR. YOUTH: Yes.

COMMISSIONER BROWN-BLAND: NCSEA Public Snider Cross-Examination Exhibit 1 will be received into evidence.

(Whereupon, NCSEA Public Snider Cross-Examination Exhibit 1 was admitted into evidence.)

MR. SOMERS: Unless there's nothing further, we would ask that -- well, not be excused but let him sit down and he'll come back for rebuttal at the appropriate time.

COMMISSIONER BROWN-BLAND: You may step down, Mr. Snider.

WITNESS: Thank you, Commissioners.

(Witness is excused.)

COMMISSIONER BROWN-BLAND: At this time, I'm going to take a brief five-minute break, and I ask the counsel to please approach. We'll go off the record.

(WHEREUPON, THERE WAS A SHORT RECESS.)

COMMISSIONER BROWN-BLAND: All right. We'll come back on the record. I believe it's -- Mr. Somers?

MR. SOMERS: I have one question just to clarify. During Chairman Finley's questions of -- to Mr. Snider, he asked two questions that Mr. Snider was unable to fully answer related to how many contracts the Companies have entered into since 2007 with new hydroelectric facilities and how many existing hydroelectric facilities that had QF contracts have had those contracts terminated since then. I just wanted to inquire if the Commissioner would like late-filed exhibits answering those questions more completely.

COMMISSIONER BROWN-BLAND: Yes, that would please the Commission.

MR. SOMERS: Thank you.

COMMISSIONER BROWN-BLAND: All right. I believe Duke has now completed its portion of the direct?

MS. FENTRESS: Of the direct. Yes, Madam Chair.

COMMISSIONER BROWN-BLAND: And we will move on to Dominion. So Ms. Kells?

MS. KELLS: Dominion would like to call Mr. Robert Trexler, please.

ROBERT J. TREXLER; Being first duly sworn, testified as follows:

DIRECT EXAMINATION BY MS. KELLS:

Q **Good afternoon, Mr. Trexler. Would you please state your full name and business address?**

A My name is Robert J. Trexler. My business address is 701 East Cary Street, Richmond, Virginia 23219.

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

A I'm employed by Dominion in the position of director of regulatory.

Q Did you cause to be prefiled in this docket on August 9, 2013 the direct testimony of Robert J. Trexler on behalf of Dominion North Carolina Power consisting of six typed pages of questions and answers and an Appendix A, which is qualifications?

A Yes.

Q Was that document prepared by you or under your supervision?

A Yes.

Q Do you have any corrections to that document?

A Yes, I do. On page 1, line 14 of my direct testimony Roman numeral VI should be a Roman numeral V.

Q And other than that correction, would your answers to the questions in that testimony be the same if you were asked those questions today?

A Yes.

Q And are they true and correct to the best of your knowledge?

A Yes.

MS. KELLS: And Commissioner, I move that the prefiled direct testimony of Mr. Trexler be copied into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: Very well. The prefiled direct testimony of Robert J. Trexler consisting of six pages filed on August 9, 2013 with one appendix will be received into evidence as if given directly from the witness stand. And I believe that testimony is non-confidential.

MS. KELLS: That is correct. Thank you.

(Whereupon, the prefiled direct testimony of Robert J. Trexler, as corrected, and Appendix A was copied into the record as if given orally from the stand.)

DIRECT 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 5000 Dominion Boulevard, Glen Allen, Virginia 23060. My current position is Director of Power Contracts for Dominion North Carolina Power ("DNCP" or the "Company"). My responsibilities include 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. What is the purpose of your testimony in this proceeding?

A. I will describe the background of DNCP's involvement in this proceeding to date and the scope of the testimony provided by the Company's other witness, Mr. Bruce E. Petrie.

Q. Have you filed other documents or comments 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, and have participated in responding to data requests of other parties to this proceeding. I incorporate by reference these documents and other comments submitted by the Company in this docket.

Q. **What is the origin of DNCP's involvement in this proceeding?**

A. This proceeding was established on June 18, 2012 by the Commission's *Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing*. That order directed DNCP to file a set of proposed rates for purchases from qualifying facilities ("QFs") no larger than five MW, showing all calculations for determining the proposed rates, including inflation rates and discount rates used. It also directed the filing of proposed standard forms of contract between DNCP and QFs, and a description of any differences between the proposed standard forms of contract and the currently approved standard forms of contract, and the reasons for the differences.

In addition, the Commission's previous biennial *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* issued on July 27, 2011 in Docket No. E-100, Sub 127 ("2010 Biennial Order") directed DNCP to file in this current biennial proceeding "long-term levelized capacity payments and energy payments calculated pursuant to the DRR method based on long-term levelized generation mixes with adjustable fuel prices for five-year, ten-year and 15-year periods..." for eligible QFs, 2010 Biennial Order at 23, as well as "proposed fixed long-term levelized avoided energy rates for QFs entitled to standard contracts." *Id.* at 25. The 2010 Biennial Order also continued the Commission's past practice of allowing DNCP to offer QFs the alternative to enter into Schedule 19-LMP with avoided cost prices based on PJM market clearing prices, subject to certain conditions, and required the Company to provide a comparison of the DRR pricing method and the PJM market pricing method. *Id.* at 24.

Q. How did DNCP respond to these directives?

A. The Company filed with the Commission a comparison of calculations of avoided cost payments under its Schedule 19-LMP and Schedule 19-DRR on July 12, 2012. On August 23, 2012, the Company filed its 2011-2012 annual status report of DNCP's activities regarding cogeneration and small power production facilities.

On November 1, 2012, as corrected on November 5, 2012, the Company filed its Comments, Exhibits and Avoided Cost Schedules ("DNCP Avoided Cost Filing"). In the DNCP Avoided Cost Filing, DNCP proposed to establish a new rate schedule, Schedule 19-FP, which would be available to all new standard rate QFs (those QFs that enter into a contract with DNCP after January 1, 2013). Schedule 19-FP would offer QFs fixed long-term energy rates, as well as the other standard rate options (such as "as available" energy payments), and would also introduce seasonal on- and off-peak hours, which the Company believes better reflect its customers' actual peaks during the year, and payments for capacity during on-peak hours only. As the Company explained in the DNCP Avoided Cost Filing, if the Commission approves Schedule 19-FP, DNCP proposes to close Schedule 19-DRR except for QFs with a currently effective contract under that rate schedule. The Company also explained other changes it proposed to make to its standard rate schedules, and its intention to continue to offer Schedule 19-LMP as an alternative available to eligible QFs. In addition, the Company proposed to change the method it uses to develop avoided cost capacity rates for its standard QF rate tariffs. In lieu of using PJM capacity auction clearing prices in the short term and blending to capacity price forecasts in the long term, the Company calculated avoided capacity costs for this biennial proceeding using the "peaker" method long held by the Commission to be a reasonable method for these calculations. Finally, the Company described its policy regarding the availability of standard rate schedules for QFs based on whether they begin delivery of power during the biennial period.

On January 25, 2013 and July 18, 2013, the Company filed updated comparisons of calculations of avoided cost payments under its Schedule 19-LMP and Schedule 19-DRR. On March 28, 2013, DNCP filed its Reply Comments to the Initial Statement of the Public Staff and to the Initial Comments of the Renewable Energy Group ("REG") that were submitted on February 7, 2013, in response to the filings of DNCP and the other utilities in this proceeding.

Q. Why is DNCP submitting this testimony now?

A. Also on March 28, 2013, the North Carolina Sustainable Energy Association ("NCSEA") filed a Motion for Consideration of Need for an Evidentiary Hearing in this proceeding, asking the Commission to consider scheduling an evidentiary hearing in this proceeding in order to address certain issues. The motion also asked that if the Commission scheduled a hearing, that it issue subpoenas for certain witnesses, and that it direct that Duke Energy Carolinas, LLC and DNCP's proposed fixed long-term avoided cost rates go into effect on a temporary basis subject to true-up based upon a final order in this proceeding.

In addition, the Reply Comments filed by the Public Staff on March 28, 2013 requested that the Commission schedule an evidentiary hearing in order to consider certain issues discussed in that filing.

On April 8, 2013, in response to the Commission's April 1, 2013 order asking for comments on the NCSEA motion, DNCP filed comments arguing that NCSEA and the Public Staff had not raised any material issues of fact that would warrant a hearing, and that the Commission had sufficient evidence in the record as it stands, with the addition of parties' proposed orders, to make determinations on the issues raised without an evidentiary hearing.

On June 6, 2013, the Commission issued an order granting NCSEA's motion and setting for hearing the issues raised by REG's February 7 comments and by NCSEA and the Public Staff, including, but not limited to, the appropriate performance adjustment factor ("PAF") for solar QFs, the appropriate methodology by which to calculate avoided cost rates based on CT capacity costs, and the appropriate CT useful life. The Commission also noted the additional issues of the use of average CT costs and the appropriate level of consistency between Integrated Resource Planning inputs and assumptions and the inputs and assumptions used to calculate proposed avoided cost rates. As amended by its rescheduling order issued July 1, 2013, the Commission directed DNCP and the other utilities to submit direct testimony by August 9, 2013. The Company is submitting my testimony and that of Mr. Petrie in response to this directive.

Q. Which issues set for hearing are addressed by Mr. Petrie's testimony?

A. Mr. Petrie addresses those issues set for hearing by the Commission that are relevant to DNCP. Specifically, he describes the methodology used by the Company to calculate the avoided capacity cost rates for its proposed Schedule 19-FP rate schedule and discusses the major assumptions used by DNCP for the CT included in its analysis of avoided costs. As part of that discussion, Mr. Petrie addresses why the Company does not include land costs in its estimated installed CT costs and why it uses costs associated with a brownfield site rather than a greenfield site in that calculation for this proceeding. Mr. Petrie also addresses the PAF used by DNCP for its avoided capacity rate calculations and discusses other issues related to the PAF.

Q. Does Mr. Petrie's testimony address the other issues that are the subject of this hearing as specified by the Commission in its June 6 order?

A. No, the other issues set for hearing do not directly pertain to DNCP and so the Company takes no position on those issues at this time, subject to issues being raised in other parties' direct testimony that the Company may address in its rebuttal testimony.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF ROBERT J. TREXLER

I am the Director of Power Contracts for Virginia Electric and Power Company in Richmond, VA. 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, which oversees both the administration and operational aspects of the Wholesale sales and NUG power purchase contracts.

BY MS. KELLS:

Q **Mr. Trexler, do you have with you a summary of your direct testimony?**

A Yes, I do.

Q **Would you provide that for me?**

A Yes. (Summary read into the record.)

Trexler Summary of Direct Testimony

My name is Robert Trexler, and I am Director of Regulation for Dominion North Carolina Power. My direct testimony in this case describes the background of Dominion's involvement in the case to date, and explains the scope of the testimony provided by the Company's other witness here today, Mr. Bruce E. Petrie. As I state in my testimony, in Dominion's November 1, 2012 filing of its Comments, Exhibits and Avoided Cost Schedules, the Company proposed to establish a new avoided cost rate schedule, Schedule 19-FP. Proposed Schedule 19-FP introduced seasonal on- and off-peak hours, which the Company believes better reflect its customers' actual peaks during the year, and payments for capacity produced during on-peak hours only. If the Commission approves Schedule 19-FP, Dominion proposes to close out its existing Schedule 19-DRR, except for QFs with currently effective contracts under that tariff. The Company also proposes to continue to offer Schedule 19-LMP as an alternative to eligible QFs. Finally, Dominion proposed to change the method it uses to develop avoided cost capacity rates for standard QF rate tariffs, by adopting the peaker method long held by the Commission to be a reasonable method for calculating avoided costs.

This concludes my summary of my direct testimony.

MS. KELLS: Mr. Trexler is available for cross.

COMMISSIONER BROWN-BLAND: All right. Cross-examination for this witness?

MR. YOUTH: I've got a few questions, Mr. Trexler.

COMMISSIONER BROWN-BLAND: Mr. Youth.

CROSS EXAMINATION BY MR. YOUTH:

Q Mr. Trexler, does Dominion North Carolina Power have solar in its North Carolina rate base?

A I do not have knowledge that it does. I -- I do not believe it does.

Q Would Mr. Petrie know the answer to that question?

A He might.

Q How -- how might I secure an answer in this proceeding to that question?

MS. KELLS: I believe Mr. Petrie probably would probably --

MR. YOUTH: I'll reserve the rest of my questions for Mr. Petrie.

COMMISSIONER BEATTY: No questions. Thank you.

COMMISSIONER BROWN-BLAND: No cross-examination? No redirect, I take it. Any questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: Okay. Subject to the testimony of Mr. Petrie, is that something that could be provided the answer to whether there's solar in Dominion's North Carolina rate base in a late-filed exhibit?

MS. KELLS: Yes.

COMMISSIONER BROWN-BLAND: Then we'll wait, subject to seeing if Mr. Petrie can answer that question. Okay. It appears there's no questions, further questions for this witness. Ms. Kells was true to her word. This witness is free to step down.

(Witness is excused.)

MS. KELLS: Thank you. We'd like next to call Mr. Bruce Petrie.

BRUCE E. PETRIE; Being first duly sworn,
testified as follows:

DIRECT EXAMINATION BY MS. KELLS:

Q Mr. Petrie, will you please state your full name and business address?

A My name is Bruce Petrie. My business address is 5000 Dominion Boulevard, Glen Allen, Virginia.

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

A I'm employed by Dominion North Carolina Power, and my position is manager of generation system planning.

Q Did you cause to be prefiled in this docket on August 9, 2013, a public version of the direct testimony of Bruce E. Petrie on behalf of Dominion North Carolina Power consisting of 22 typed pages of questions and answers, an Appendix A with your qualifications, and a confidential version of the same direct testimony?

A I did.

Q Was that document prepared by you or under your supervision?

A It was.

Q Do you have any corrections to that document?

A No.

Q Would your answers to the questions in that testimony be the same if you were asked those questions today?

A Yes.

Q And are they true and correct to the best of your knowledge?

A Yes.

MS. KELLS: Commissioner, I move that the public -- that Mr. Petrie's prefiled direct testimony be copied into the record as if given orally from the stand

and would like the confidential version to be maintained, those portions that are confidential.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed, and the public version of the direct testimony of Bruce E. Petrie consisting of 22 pages filed August 9th shall be admitted into evidence and the confidential version shall also be admitted and maintained as confidential.

(Whereupon, the public version of the prefiled direct testimony of Bruce E. Petrie and Appendix A was copied into the record as if given orally from the stand. The proprietary version of the testimony has been filed under seal.)

DIRECT TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 136
PUBLIC 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. What is the purpose of your testimony in this proceeding?

A. I will describe the methodology that was used to calculate the avoided capacity cost rates for DNCP's proposed Schedule 19-FP rate schedule filed in this docket. As part of this discussion, I will also address the performance adjustment factor ("PAF") issues that have been raised in this proceeding.

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, and have participated in responding to data requests of other parties to this proceeding.

Q. What methodology did the Company use to calculate avoided capacity costs for Schedule 19-FP?

A. The Company used the construction costs and fixed operating and maintenance costs of a combustion turbine ("CT") to determine its avoided capacity cost. In the context of the Commission's biennial avoided cost proceedings this methodology is commonly referred to as the "peaker method." Under the peaker method, the development of the capacity rates starts with the estimated construction cost and annual fixed costs of a CT, in millions of dollars. From these capital expenditures, the annual revenue requirements, including financing costs, for the new CT are calculated. The annual revenue requirements are then converted to an economic carrying charge ("ECC") rate in millions of dollars per year. The ECC rate escalates annually at an assumed rate of inflation. For rate schedules such as Schedule 19-FP, which provide for capacity payments during on-peak periods only, the annual costs (in millions of dollars) are then converted to the appropriate $/kWh capacity rates. The last step in implementing the peaker methodology as adopted in North Carolina is to adjust the $/kWh capacity rates by the Commission-prescribed PAF.

Q. Please describe the major assumptions used by the Company for the CT included in its analysis.

A. The CT used by the Company in its analysis is a two-unit addition at an existing Company owned site and is assumed to be operational in 2013. The CT is 400 MW (summer rating) in size, with a nominal installed cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** plus annual costs related to fixed O&M and natural gas pipeline firm transportation costs, with a book life of 36 years. The long term inflation rate was assumed to be 1.84% per year.

Q. Why did the Company select a 400 MW size for the CT?

A. The 400 MW size was selected based on the Company's 2012 Integrated Resource Plan filed with the Commission on August 31, 2012 in Docket No. E-100, Sub 137 (the "2012 IRP").

Q. Were the other inputs and assumptions used in the Company's avoided cost analysis for this proceeding also consistent with the inputs and assumptions in the Company's 2012 IRP?

A. Yes.

Q. What was the basis for the assumed in-service date for the CT?

A. The in-service date of the CT was assumed to be January 1, 2013, because the proposed Schedule 19-FP tariff is available to any QF that would become operational during the biennial period January 2013 through December 2014.

Q. What is the basis for the nominal installed costs of the CT?

A. The CT's nominal installed cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was based on the installed costs of a CT contained in the 2012 IRP. Because the CT costs in the 2012 IRP were stated in 2016 dollars, to calculate avoided capacity costs for this proceeding, the Company de-escalated the CT capital costs from 2016 dollars to 2013 dollars using the assumed long-term inflation rate of 1.84% per year.

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Q. Does the Company's estimate of the installed costs of the CT include land costs?

A. No. As the Company explained in its March 28, 2013, Reply Comments of Dominion North Carolina Power in this proceeding ("*DNCP Reply Comments*"), 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. *See DNCP Reply Comments* at pages 4-5. Because the Company would not incur or avoid any land costs for the CT, the avoided land costs are $0.

Q. Did not the Commission in Docket No. E-100, Sub 87 hold that DNCP was required to include land costs in its calculation of capacity credits?

A. Yes, but only in the circumstances of that proceeding. In Docket No. E-100, Sub 87, DNCP used the projected capital cost of the Ladysmith CT units 1-2 for its avoided capacity calculations. The Public Staff pointed out that the Company's estimates did not include the cost of land, and the Company agreed to add the cost of land because the Ladysmith site was a greenfield site (i.e., the Company would have to purchase land for the generating units). However, as the Commission noted in its order in that proceeding, the Company did not agree that inclusion of land costs was always appropriate:

> 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).

Because the Company had agreed to the Public Staff's request to include land costs in that proceeding, 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).

In short, the Commission did not hold in Docket No. E-100, Sub 87, and the Company did not concede, that land costs should be included in avoided costs estimates based on installation of new capacity at a brownfield site, when in fact no such costs would be incurred or avoided.

Q. Would the inclusion of land 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 cost rates 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). As discussed above, because the Company would not incur or avoid any land costs associated with the CT on the brownfield sites, the avoided land costs are $0. Requiring the Company's ratepayers to bear costs that are not in fact avoided is not just and reasonable, and 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. **Has the Company prepared a comparison of the CT capital costs at a brownfield site excluding land cost and the CT capital costs at a brownfield site including land costs?**

A. No, because there are no land costs associated with installation of a CT on a brownfield site. However, in response to a Public Staff data request, the Company did calculate the capital costs of a CT installed at a greenfield site.

Q. **How do the capital costs for a CT at a brownfield site and at a greenfield site differ?**

A comparison of the difference between the capital costs of a CT installed at a brownfield site (which, as explained above, is what the Company would do) and a CT installed at a greenfield site, which the Company does not plan to do in the 15-year planning horizon of the 2012 IRP, is set out below.

Nominal installed cost of CT

	$/kW 2016$	1 + Inflation rate	$/kW 2013$
Brownfield	[BEGIN CONFIDENTIAL] $[redacted] [END CONFIDENTIAL]	1.0184	[BEGIN CONFIDENTIAL] $[redacted] [END CONFIDENTIAL]
Greenfield	[BEGIN CONFIDENTIAL] $[redacted] [END CONFIDENTIAL]	1.0184	[BEGIN CONFIDENTIAL] $[redacted] [END CONFIDENTIAL]

Q. Why does the chart show amounts stated in both 2016 dollars and 2013 dollars?

A. As discussed above, the Company's CT capital cost estimate was based on the cost estimates of the 2012 IRP. Because the CT costs in the 2012 IRP were stated in 2016 dollars, to calculate avoided capacity costs for this proceeding, the Company de-escalated the CT capital costs from 2016 dollars to 2013 dollars using the assumed long-term inflation rate of 1.84% per year.

Q. What is the difference in brownfield and greenfield CT capital cost estimates?

A. In 2013 dollars, the capital cost for a CT installed at a greenfield site is $43/kW higher (approximately 6.9%) than the capital costs for a CT installed at a brownfield site.

Q. How much would the Company's avoided capacity rates increase if the capital costs of a greenfield installation were utilized?

A. The table below shows the increase in capacity rates that would result if greenfield CT costs are used to calculate the Company's avoided capacity costs. The rates based on a greenfield CT are 12.2% higher than rates based on a brownfield CT. Because the Company does not plan to install CTs on a greenfield site, the Company believes that such amounts would result in the ratepayer bearing and the Company paying costs in excess of its avoided costs in violation of PURPA.

<u>Run of river QFs (PAF 2.0)</u>

FIXED RATES ¢/kWh (2013$)			
Brownfield Costs Rates (from Schedule 19-FP)	5-Year	10-Year	15-Year
On-Peak Summer	5.895	6.095	6.263
On-Peak Non-Summer	3.930	4.063	4.175
Greenfield Costs			
On-Peak Summer	6.631	6.841	7.027
On-Peak Non-Summer	4.421	4.560	4.685
Increased ¢/kWh using Greenfield Costs			
On-Peak Summer	0.736	0.746	0.764
On-Peak Non-Summer	0.491	0.497	0.51

<u>All other QFs (PAF 1.2)</u>

FIXED RATES ¢/kWh (2013$)			
Brownfield Cost	5-Year	10-Year	15-Year
On-Peak Summer	3.537	3.657	3.758
On-Peak Non-Summer	2.358	2.438	2.505
Greenfield Costs			
On-Peak Summer	3.979	4.105	4.216
On-Peak Non-Summer	2.653	2.736	2.811
Increased ¢/kWh using Greenfield Costs			
On-Peak Summer	0.442	0.448	0.458
On-Peak Non-Summer	0.295	0.298	0.306

Q. **What Performance Adjustment Factor ("PAF") did the Company use for its avoided capacity rate calculations for Schedule 19-FP?**

A. In compliance with long-standing Commission precedent, the Company used a PAF of 2.0 for hydro projects with no storage capability and no other generation ("run-of-river" QFs), and a PAF of 1.2 for all other QFs eligible for Schedule 19-FP.

Q. **Have other parties to this proceeding recommended a change to Commission practice as to the PAF?**

A. The Renewable Energy Group ("REG") proposes that the tariff capacity rates for wind and solar projects be based on a PAF of 2.0. *See Renewable Energy Group's Initial Comments* at 10 (Feb. 7, 2013) ("*REG Initial Comments*"). The Public Staff, while not expressing a definitive position on the PAF issue in its filings in this proceeding, has stated that it would be appropriate for the Commission to address the need for a solar-related PAF in an evidentiary hearing. *See Public Staff Reply Comments* at 13 (Mar. 28, 2013). The North Carolina Sustainable Energy Association ("NCSEA") supported the REG position. *See NCSEA Comments* at 39 (Feb. 7, 2013).

Q. **What is the basis for REG's position?**

A. REG relies primarily on language from the Commission's order in Docket No. E-100, Sub. 106, where the Commission stated that:

> [t]he 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 the run-of-river hydro generating facilities included in the rate base of the State's utilities, which are able to recover the full costs of these facilities. With respect to solar and wind QFs, however, this comparison has no relevance, because the State's utilities have no solar or wind facilities in rate base. On the other hand, the Commission agrees that solar and wind QFs, like run-of-river facilities, have no control over their energy source. This is a legitimate argument for treating them in the same manner as run-of-river hydro QFs.

In the Matter of Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2006, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 20 (Dec. 19, 2007) ("2006 Biennial Order") (cited by *REG Initial Comments* at 7-8).

REG argues that solar and wind QFs, like run-of-river facilities, have no control over their energy sources, and no storage capability, and therefore should also receive a PAF of 2.0. *See REG Initial Comments* at 8. REG further argues that a PAF of 2.0 for wind and solar QFs should be imposed because utilities recover their full capacity cost for utility units regardless of when their facilities produce power. *See id.* at 9. Finally, REG claims that FERC's 2010 and 2011 decisions regarding the avoided cost regime in California support the increase in the PAF to 2.0 for wind and solar QFs. *See id.* at 9-10 (citing *California Public Utilities Commission*, 132 FERC ¶ 61,047, *order granting clarification and dismissing reh'g,* 133 FERC ¶ 61,059 (2010), *order denying reh'g,* 134 FERC ¶ 61, 044 (2011) ("*CPUC*")).

In its reply comments, the Public Staff summarized the REG position and noted that in Docket No. E-100, Sub 106, the Commission observed that the passage of Senate Bill 3 ("SB 3") created a renewable energy and efficiency portfolio standard ("REPS") and "established strong state policy support for renewable energy sources . . . ." *Public Staff Reply Comments* at 11. The Public Staff also stated that FERC's *CPUC* decisions are relevant given the requirements of SB 3. *Id.* at 13.

Q. **Does the Company agree that the PAF for solar and/or wind QFs should be increased to 2.0?**

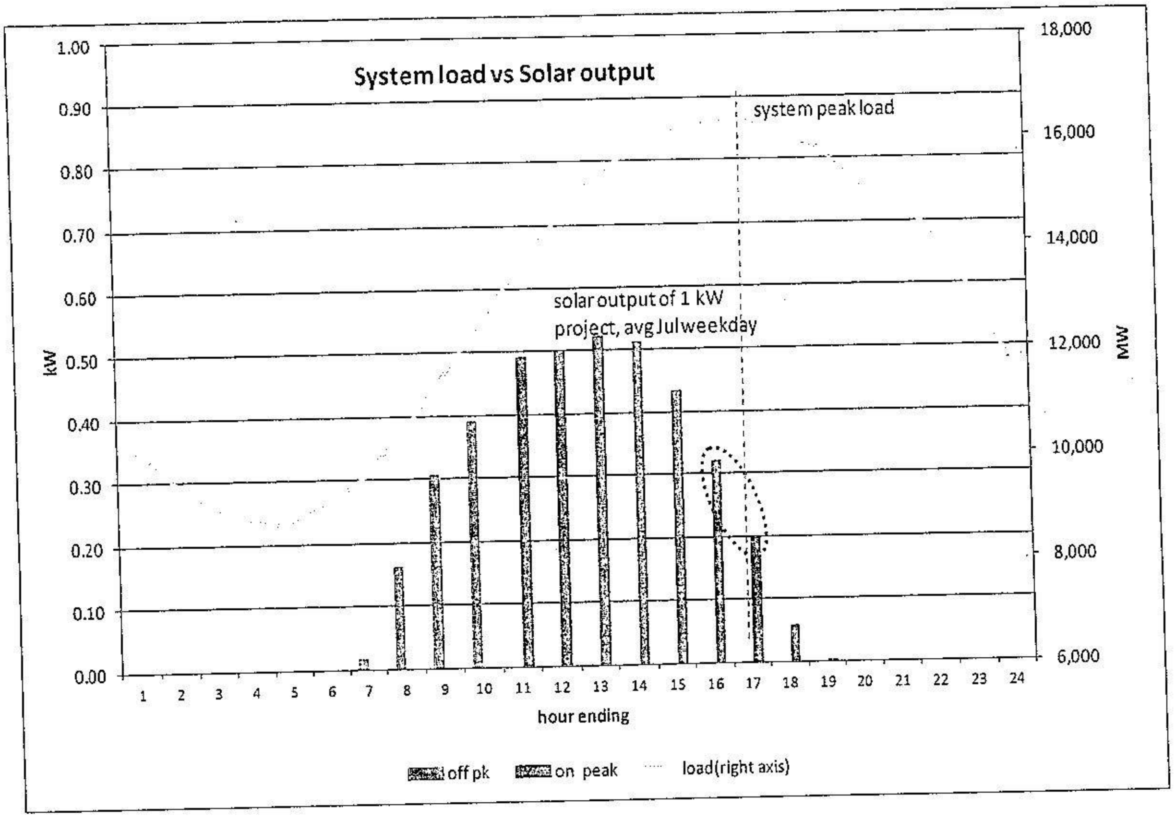
A. No. First, there is no logical reason to pay a premium capacity rate to new renewable resources that are not likely to generate reliably at the time of the Company's system peak load. Second, the rate treatment of generating units in the Company's rate base is irrelevant to the determination of avoided costs. Third, SB 3 does not justify the arbitrary increase in the PAF for solar and wind QFs. Finally, FERC's holdings in the *CPUC* provide no guidance on the PAF issue in this proceeding because of the significant differences between California's implementation of PURPA and that of this Commission.

Further, if the Commission determines that a re-examination of its current PAF policy is needed, such an inquiry should include all QFs, including run-of-river hydro QFs, and should be based on an in-depth examination of the likely avoided capacity costs based on the actual operational and capacity characteristics of these types of facilities. The appropriate PAF should reflect both the availability and capability during the tariff defined on-peak hours, and also both the availability and capability of the QF resource at the time of the utility's system peak load. The Company does not believe that there is sufficient evidence in the record of this proceeding to make such a determination, and rather than further prolonging this proceeding, and the attendant uncertainty for both QFs and the Company, the issue should be examined in a separate proceeding or workshop.

Q. Why is a PAF of 2.0 for a solar QF inappropriate?

A. In one sense, solar generation is attractive because it can produce energy during sunny daytime hours when the aggregate customer demand is high. However, a utility plans for capacity additions based on its forecasted annual system peak load. It is well known that DNCP's annual system peak load typically occurs sometime around 4 or 5 p.m. (hours ending 1600 and 1700 on the graph below) on a summer weekday. At that particular time, a solar QF, on average, is likely to produce only 20 to 40 percent of its maximum potential output.

The graph below illustrates the timing misalignment, and the point that the solar generation is only partially effective in allowing the utility to avoid the construction of new CT capacity.



Because of this mis-alignment and considering that solar panels are not functionally equivalent to a dispatchable CT, basing the capacity rate for solar QFs on the full cost of the peaker, plus requiring a PAF of 2.0, would result in the solar QF being paid for capacity that is not avoided by the Company. In recognition that capacity has value only to the extent that a generator can reliably operate during the critical summer peak hours, the PJM capacity market, for example, gives new solar resources a capacity credit of only 38% of their installed MW value. Under this approach, it would take 1,053 MW of new solar capacity for the utility to avoid having to build a new 400 MW CT plant. Stated in terms of the peaker method calculation, which uses the full cost of a peaker, a PAF of 1.2 recognizes this timing misalignment and results in a closer representation of DNCP's avoided cost.

Q. Why is a PAF of 2.0 for a wind QF inappropriate?

A. At the time of the system annual peak load, the expected generation from a 1 MW wind unit would be even less than the expected solar generation from a similarly sized unit. Wind potential is very site specific, but on average, at the time of the system peak load, a wind QF is likely to produce only 10 to 20 percent of its maximum potential output. Again, as an example, the PJM capacity market recognizes this disconnect by giving new wind resources capacity credit for only 13% of their installed MW value. As with solar QFs, paying a wind QF the full cost of the peaker plus requiring a PAF of 2.0 would result in overpayment to the QF for the capacity that is actually avoided. Also as with solar QFs, in light of the timing misalignment between system peak load and likely wind output and stated in terms of the peaker method calculation, which uses the full cost of a peaker, a PAF of 1.2 results in a closer representation of DNCP's avoided cost.

Q. What is the additional burden on ratepayers if the Commission orders a PAF of 2.0 for solar and wind QFs?

A. Adjusting the PAF from 1.2 to 2.0 for wind and solar QFs would increase the capacity rates to those QFs by approximately 66% - an increase that will be borne by customers – with no corresponding additional benefit to the Company or those customers. Specifically, this adjustment to the PAF would result in these customers bearing the burden of the Company paying a capacity rate to these QFs that exceeds its avoided capacity cost rate.

Q. Is the inclusion of solar or wind generating facilities in a utility's rate base relevant to the appropriate PAF for solar or wind QFs?

A. No. In this proceeding the Commission is determining the avoided costs of the Company pursuant to PURPA. Avoided costs under PURPA are not determined by reference to the retail rate base of an electric utility, but instead are "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).

Likewise, in this proceeding the Commission is not determining the avoided costs of an individual solar or wind facility and the "Commission has never indicated that the calculation of incremental costs which the utility would have to incur but for a purchase from a particular QF should be based upon the same type of generating unit that that particular QF is proposing . . . ." *In the Matter of Economic Power & Steam Generation, LLC,* Order on Arbitration at 6, Docket No. SP-467, Sub 1 (June 18, 2010).

The fact that a utility is able to recover the full costs of generating units included in its rate base that may not run at a 100% capacity factor is not relevant to the calculation of avoided costs. Unlike a QF, a utility must build sufficient generation to meet its system peak load and reserve requirements, in order to plan for load forecasting uncertainty and generator unplanned outages, including unavailability of QFs under contract to the Company.

Q. Does SB 3 justify the increase of the PAF for solar and wind QFs to 2.0?

A. No. Among other things, SB 3 established a REPS for North Carolina. *See* N.C. Gen. Stat. § 62-2(a)(10). The requirements of the REPS are specified in N.C. Gen. Stat. § 62-133.8, which requires that certain percentages of utilities' retail sales be met through renewable resources. *See* N.C. Gen. Stat. § 62-133.8(b)(1). In addition, beginning in 2018, at least two-tenths of a percent of the total electric power in kWh sold to retail customers by utilities must be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities that use solar hot water, solar absorption cooling, solar dehumidification, solar thermally driven refrigeration and solar industrial process heat. *See* N.C. Gen. Stat. § 62-133.8(d).

However, and notably, SB 3 does not mandate a rate for purchases from renewable energy facilities. Instead, it simply provides that if a utility is required to pay more than avoided costs to purchase power from such facilities in order to satisfy REPS requirements, the utility is entitled to recover these excess costs, to the extent they were reasonable and prudently incurred. *See* N.C. Gen. Stat. § 62-133.8(h). The absence of any directive on rates in SB 3 is in stark contrast to N.C. Gen. Stat. § 62-156, which as the Commission stated in Docket No. E-100, Sub 106, formed a basis, in part, for the imposition of a PAF of 2.0 for run-of river QFs. *See 2006 Biennial Order* at 20. That statute directed the Commission to encourage long-term contracts to increase the economic feasibility of hydro QFs and specifically spoke to the determination of avoided costs for hydro QFs. *See* N.C. Gen. Stat. § 62-156.

Q. Are there other incentives to the development of renewable resources?

A. It is my understanding that there are state and federal tax incentives to encourage the development of renewable resources. Also, renewable generators produce renewable energy certificates ("RECs") that can be sold into the market.

Q. Has the REPS and other aspects of SB 3 and other state and federal incentives in fact encouraged the development of renewable resources in North Carolina?

A. Yes. According to NCSEA, North Carolina's clean energy sector has grown substantially since the enactment of SB 3. As of September 2012, the clean energy sector accounts for over 15,200 full-time equivalent employees and in 2012 "conservatively generated over $3.7 billion dollars in North Carolina gross revenue . . . ." *NCSEA Comments* at 2. Small power producers accounted for $100 million in private investment in North Carolina in tax year 2011. *See id.* at 2-3. Further, according to NCSEA, over 1100 North Carolina companies were actively conducting business in the clean energy sector in 2012, and North Carolina clean energy companies accounted for over 1400 offices in 86 counties in North Carolina. *See* NCSEA *2012 North Carolina Clean Energy Industries Census* at 2, 4 (the full census is available on NCSEA's website at http://energync.org/).

Q. In light of this record, is an additional subsidy to solar and wind QFs in the form of an increased PAF necessary to encourage their development?

A. No. It appears that the multiple layers of governmental incentives are already providing sufficient encouragement to those QFs and other forms of renewable resources.

Q. Do FERC's decisions in the *CPUC* cases provide any guidance as to whether a PAF of 2.0 is appropriate for solar and wind QFs?

A. Because of the differences between the avoided cost regime in North Carolina and the avoided cost regime in California on which the *CPUC* decisions were based, the Company does not believe that FERC's *CPUC* decisions provide meaningful guidance on the PAF issue in this case.

The *CPUC* case arose out of the set of California laws and regulations that essentially limited the pool of new supply options available to its utilities to combined cycle gas turbines, renewable energy, other non-carbon emitting resources and combined heat and power (CHP) facilities. *See California Public Utilities Commission,* Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 at P 10 (2010) ("*CPUC Clarification Order*"). As part of that effort, California legislators passed a law requiring California utilities to offer to enter into ten-year contracts with CHPs that met certain more stringent efficiency and emission standards, at prices set by the CPUC. *See id.* at P 4. Originally, the requirement was to have applied to purchases from all CHPs, but FERC held that the CPUC could not set wholesale rates for purchases from non-QF CHPs. *See id.* at P 5. The question for FERC in the *CPUC*

Clarification Order was whether PURPA allowed the CPUC to create a multi-tiered avoided cost rate structure that calculated estimated avoided prices for purchases from CHP QFs discretely from estimated avoided cost prices for purchases from other QFs. *See id.* at PP 19-20.

FERC held that a multi-tiered avoided cost structure that takes into account a state imposed obligation that utilities purchase energy from particular sources for a long duration could be consistent with PURPA. *See id.* at P 26. FERC explained that, because in "determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration," the CPUC could account for actual procurement requirements and resulting costs imposed on utilities in California. *See id.* For example, it determined that "'if a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural gas-fired unit, for example, would not be a source 'able to sell' to that utility for the specified renewable resources segment of the utility's energy needs, and thus would not be relevant to determining avoided costs for that segment of the utility's energy needs.'" *Id.* at P 27.

Thus, under the *CPUC Clarification Order,* if a state required that a utility purchase 10 percent of its energy needs from solar facilities, the state could also determine the avoided costs for that 10 percent segment based on the avoided costs of such facilities (i.e., the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from solar QFs, such utility would generate itself or purchase from other sources).

This Commission, however, has not adopted a multi-tiered avoided cost regime where the avoided costs of solar QF or wind QFs are calculated separately (i.e., without regard to and excluding the costs of a CT) for purposes of a resource-type set aside. Nor is there any evidence in the record of this proceeding that would support the Commission's creation of such segmented avoided costs rates. Further, in addition to the time associated with gathering such evidence, adoption of such a multi-tiered approach would require careful consideration of a number of issues, which would further prolong this proceeding. For example, once a utility has satisfied its procurement requirement for a specified energy source (e.g., solar), the Company believes that the utility would have no further capacity needs for solar resources and therefore no obligation to purchase any further capacity from solar QFs. The utility would, of course, retain its PURPA obligation to purchase energy from solar QFs.

In summary, due to the distinction between the context of the CPUC case and the PURPA implementation approach in North Carolina, the Company believes that the *CPUC* decisions do not provide any meaningful guidance on the issues in this proceeding. Further, even were the Commission to decide that it is appropriate to adopt a multi-tiered avoided cost regime, there is no evidence in the record to support such an approach being adopted in this proceeding.

Q. **Are there any adjustments that the Commission should consider in this proceeding relating to the PAF?**

Yes, the Company believes that the Commission should impose an annual maximum or "cap" on capacity payments resulting from the application of a PAF in order to avoid the real possibility of payments to QFs in excess of the Company's avoided costs.

The method of calculating hourly capacity rates is based on the annual total avoided cost for a peaker, which is converted to a levelized on-peak hourly ¢/kWh rate by application of the on-peak hours for each day, the capacity factor or PAF, and a discount rate. This method allows a QF to receive the full annual capacity payment available for a year if the QF produces 100% of its dependable capacity during 83.3% or 50% (equivalent to a PAF of 1.2 and 2.0 respectively) of the total on-peak hours in the calendar year. If a QF produces 100% of its dependable capacity for greater than 83% or 50%, as applicable, of the on-peak hours, the QF could earn more than 100% of full capacity payments.

The Company's proposed capacity payment cap would be calculated as follows: in any calendar year, the maximum annual capacity payments made to the QF would be no greater than the dependable or contracted capacity, multiplied by the annual capacity on-peak hours, and further multiplied by the applicable average on-peak capacity price (in cents per kilowatt-hour) divided by the applicable PAF (i.e., by 1.2 for a PAF of 1.2 or 2.0 for a PAF of 2.0). In the beginning and ending year of the QF's contract term, the hours referenced above would be prorated.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

APPENDIX A

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 direct testimony?

A Yes, I do.

Q Would you please provide that summary now?

A (Summary read into the record.)

Petrie Summary of Direct Testimony

Good morning, my name is Bruce Petrie, and I am the Manager of Generation System Planning for Dominion North Carolina Power.

In my direct testimony filed in this case, I describe the methodology used to calculate the avoided capacity cost rates for Dominion's proposed Schedule 19-FP rate schedule filed in this docket. I also address the performance adjustment factor, or PAF, issues that have been raised in this proceeding.

As my direct testimony explains, for the first time in its North Carolina biennial avoided cost filings, the Company in this case has proposed to use the "peaker method" to determine its avoided costs and arrive at its proposed capacity rates. The inputs and assumptions on which Dominion based its CT cost calculations are consistent with those supporting the installed cost of a CT included in Dominion's 2012 IRP. Consistent with the installation of such a CT on a Company-owned site, also as reflected in the IRP, Dominion did not include land or other "greenfield" costs in its CT cost calculation, because the avoided land costs for that CT are zero.

My direct testimony also addresses the PAF issue that has been raised in this case. In short, Dominion does not support a PAF of 2.0 for QFs other than run-of-river facilities, including for solar and wind QFs, for several reasons.

First, there is a timing misalignment between the time of a solar facility's greatest output and the time of the utility's greatest load demands, such that a solar facility is only partially effective in allowing Dominion to avoid constructing new CT capacity. Due to this mismatch, paying solar and wind QFs a capacity rate based on the full avoided cost of a peaker unit, plus a PAF of 2.0, would result in Dominion overpaying these QFs by paying them for capacity that Dominion is not avoiding.

Second, despite intervenors' assertions, the rate treatment of generating units in the Company's rate base is a separate issue from the determination of avoided costs. Unlike QFs, Dominion is required by law to plan for capacity additions to meet its load. Dominion's recovery of the costs of its own capacity resources is a separate issue from the appropriate PAF for certain QFs.

Third, Senate Bill 3 does not justify an increase in the PAF for solar and wind QFs. The law does not mandate a rate for purchases from renewable energy facilities. In addition, based on the Company's observations, there appears to be strong interest and support for QF development in this state already, such that a 2.0 PAF for solar and wind QFs is not necessary and not justified, especially in light of the fact that it would result in payments to solar and wind QFs in excess of Dominion's avoided costs.

Finally, the CPUC cases raised in other parties' testimony do not support the imposition of a PAF of 2.0 for wind and solar facilities. The avoided cost regime in California on which those decisions are based is not the same regime that governs the Company here. North Carolina currently does not provide for the separate calculation of avoided costs for different types of QFs, and there is no evidence in the record in this proceeding to support the adoption of such an approach.

As I discuss in my direct testimony, while Dominion does not support an increased PAF for solar and wind QFs, it does believe that an annual maximum or "cap" on capacity payments resulting from the application of a PAF would be appropriate to avoid the possibility that a QF could earn more than 100% of full capacity payments, and thus exceed the Company's avoided costs.

However, in general, if in response to the intervenors' arguments made here, the Commission does determine that a re-examination of its current PAF policy is needed, Dominion believes as I state in my direct testimony that that inquiry should consider all types of QFs, including run-of-river hydro QFs, and should be undertaken in a separate, more general proceeding or workshop, rather than prolong this proceeding.

This concludes my summary of my direct testimony, thank you.

MS. KELLS: He is available for cross.

COMMISSIONER BROWN-BLAND: All right. So we will recess at this time and come back at 9 o'clock in the morning and begin cross-examination of this witness. When we start back you, Mr. Petrie, can just take your place at the witness stand.

All right. So until tomorrow morning at 9:00.

(Whereupon, hearing adjourned.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

CERTIFICATE

I, Cynthia W. Rice, 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 11th day of November, 2013.

Cynthia W. Rice

Cynthia W. Rice, Court Reporter
Notary Public No. 200602400090