PLACE: Dobbs Building, Raleigh, North Carolina

DATE: April 20, 2017

DOCKET NO.: E-100, Sub 148

TIME IN SESSION: 9:36 A.M. TO 12:32 P.M.

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

Commissioner ToNola D. Brown-Bland

Commissioner Don M. Bailey

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Lyons Gray

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2016

VOLUME 6

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P R O C E E D I N G S

CHAIRMAN FINLEY: All right. Ms. Mitchell, you have a motion?

MS. MITCHELL: Mr. Chairman, Charlotte Mitchell, counsel for NCSEA. After consultation with the parties of the proceeding, I would like to make a motion requesting that the Commission excuse NCSEA Witness Strunk's appearance in the hearing. All parties have indicated that they waive their right to cross examine this witness.

CHAIRMAN FINLEY: All right. Without objection, that motion is allowed.

MS. MITCHELL: Thank you, sir. And at this time I'd ask that his prefiled direct testimony consisting of 16 pages and four exhibits be accepted into evidence.

CHAIRMAN FINLEY: Without objection, his testimony consisting of 16 pages is copied into the record as though given orally from the stand, and his exhibits are marked for identification as premarked in the filing and accepted into evidence.

(Whereupon, the prefiled direct testimony of Kurt G. Strunk was copied into the record as if given orally from the stand.)

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

DIRECT TESTIMONY

OF

KURT G. STRUNK

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kurt G. Strunk. My business address is 1166 Avenue of the Americas, New York, New York 10036.

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

A. I am employed as a Director of National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its principal offices in a number of major U.S. and European cities. NERA's experts have advised on power sector development since the firm's founding in 1961. We have been influential in major initiatives such as marginal cost pricing for electric utilities, sector restructuring and the competitive procurement of power supply.

Q. PLEASE DISCUSS YOUR PROFESSIONAL BACKGROUND.

A. I have over twenty years of professional experience working as an economist in the power sector. My practice at NERA focuses on financial matters of energy firms. I frequently serve as an expert on the requirements of investors with regard to committing capital to energy sector investments. My work in matters relating to power generation is extensive and includes resource planning, asset and contract valuation, and competitive bidding. I have worked on dozens of assignments related to power contracting and generation development.

My current curriculum vitae, which more fully details my educational, consulting and testifying experience, is provided in Exhibit 1 to this testimony.

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

A. No, I have not.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY COMMISSIONS IN OTHER JURISDICTIONS?

A. Yes. I frequently serve as an expert in matters before state and federal regulatory commissions. I have presented expert evidence in matters before the Hawai'i Public Utilities Commission, the Maryland Public Service Commission, the Massachusetts Energy Facilities Siting Board, the Nevada Public Utilities Commission, the Ohio Public Utilities Commission, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, as well as the Federal Energy Regulatory Commission and the National Energy Board of Canada.

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

A. The purpose of my testimony is to evaluate whether reduction in term from fifteen years to ten years and proposed two-year energy pricing resets for the

Commission-approved standard power purchase agreement ("PPA") rates and contract terms available to qualifying facilities (the "Standard Offer") proposed by Duke Energy Carolinas, LLC, Duke Energy Progress, LLC (collectively, "Duke") and Dominion North Carolina Power ("Dominion"), (collectively, the "Utilities") will compromise the ability of new Qualifying Facilities ("QFs")[1] to secure reasonable terms for the long-term financing necessary to enable construction of those facilities.

Q. WHAT DATA AND INFORMATION HAVE YOU RELIED UPON FOR THE DEVELOPMENT OF YOUR TESTIMONY?

A. Exhibit 2 identifies the documents I relied upon in forming the opinions presented in my testimony. These opinions are also based on my experience working on matters related to the development of new power generation facilities in various jurisdictions.

Q. WHAT HAVE THE UTILITIES PROPOSED SPECIFICALLY RELATED TO THE STANDARD OFFER?

A. Ms. Bowman, witness for Duke, explains that Duke is proposing significant changes to the Standard Offer available to QFs. Specifically, Ms. Bowman's direct testimony identifies the following changes, among others:

---

1 By Qualifying Facilities, I mean new power generation facilities that meet the requirements of the Public Utility Regulatory Policies Act ("PURPA"), as implemented by the Federal Energy Regulatory Commission.

- Reducing the eligibility limit for the Standard Offer from 5 megawatts ("MW") to 1 MW for non-hydroelectric generators;
- Transitioning to a single, 10-year PPA with fixed, levelized capacity rates and energy rates that are adjusted every two (2) years;
- Amending Duke's Terms and Conditions to include circumstance that requires action by the Companies to comply with NERC and SERC regulations as an "an emergency condition;"
- Amending the Companies' standard PPAs to ensure that the Commission's eligibility threshold for the Standard Offer is not evaded by subsequent transfers of standard PPAs to a partner or affiliate of a developer of another QF of the same energy resource located within one-half mile.

Similarly, Mr. Gaskill, witness for Dominion, has proposed the following:

- Reducing the eligibility limit for the Standard Offer from five MW to one MW; and
- Reducing the term of the PPA from 15 years to 10 years.

Q. DOES YOUR TESTIMONY ADDRESS ALL OF DUKE'S AND DOMINION'S PROPOSED CHANGES?

A. No. My testimony addresses the proposed changes that are likely to have the greatest effect on the ability of QFs to have a reasonable opportunity to attract capital from potential investors. These are: 1) the reduction of the

PPA term to ten years; and 2) the adjustment of avoided energy rates every two (2) years.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that these proposed changes will not provide QFs with a reasonable opportunity to attract capital from potential investors. As I explain below, these changes will compress the recovery of capital investment in long-lived generation assets into too short a period to allow QFs to attract capital on reasonable terms.

Q. QUALIFYING FACILITIES ARE A TYPE OF INDEPENDENT POWER PRODUCER. PLEASE PROVIDE BACKGROUND ON THE BUSINESS MODEL FOR INDEPENDENT POWER PRODUCERS.

A. In states like North Carolina that have not elected to open their markets to retail competition and where wholesale competition is in most locations not facilitated by an organized wholesale market,[2] the business model for independent power production facilities relies on forward contracting. Independent power producers derive revenue and cash flow from the sale of energy and capacity to integrated utilities, which then sell bundled electricity service to final customers. These independent power producers typically

[2] Policy makers in the United States have pursued two types of market opening: 1) the introduction of retail competition; and 2) the enabling of greater wholesale competition through the implementation of organized competitive wholesale markets. In this case, I am referring both to the lack of a competitive retail market and to the lack of an organized and easily accessible wholesale market in much of the state of North Carolina.

must obtain long-term contracts to secure financing and to ensure that the independent power producers are not subject to "holdup"[3] of these highly relationship-specific investments. The holdup problem occurs when large capital investments are made to support a specific trading relationship, and then one party to that relationship acts opportunistically to usurp the other party's trading value.

Under long-term contracts used by independent power producers, the local utility typically is the purchaser of the electrical output. Holdup, in this context, would be opportunistic behavior by the purchasing utility (for example, to lower the price or to impose other unfavorable terms) after the investment has been made and the independent power producer no longer has negotiating leverage because there are no practical alternative buyers of its output. While QFs are entitled to avoided cost pricing, the pricing to which the QF will be entitled subsequent to the term of the PPA is not knowable at the time a QF makes its initial investment decision. The viability of new QFs, therefore, depends on the price and non-price terms of the PPAs that govern sales of output from those facilities and are entered into before investors commit capital to the business. Fixed pricing[4] committed for long contract durations – sufficient to provide a reasonable

[3] See: Williamson, O. 1979, Transactions-cost economics: the governance of contractual relations. *Journal of Law and Economics* 22, 233–62, "Credible Commitments: Using Hostages to Support Exchange," *American Economic Review*, September 1983, 73, 519-40, and *The Economic Institutions of Capitalism*, New York: Free Press, 1985. See also: Coase, R. 1937. The nature of the firm. *Economica* 4, 386–405.

[4] By fixed pricing, I am referring to prices that are fixed in nominal terms or prices that are fixed in real terms with period adjustments for inflation.

amortization of sunk investment costs for a long-lived asset – has traditionally underpinned the financing of new independent power production facilities.

Q. WHAT FEATURES DISTINGUISH A FINANCEABLE PROJECT FROM A NON-FINANCEABLE ONE?

A. There is no bright line differentiating a financeable project from a non-financeable one. Getting a new power project financed with reasonable quantities of debt tends to hinge on factors such as the amount of equity committed, the interest rates paid, payback periods and other terms required by lenders, as well as the lenders' perceptions of risk in extending credit to the project.

Q. WHAT TRADE-OFFS EXIST AMONG THE VARIOUS PARAMETERS AFFECTING QF DEVELOPMENT?

A. The most important trade-off among the parameters affecting QF development is between the PPA duration and the price at which a QF will have a reasonable opportunity to attract capital from potential investors. Reducing the PPA duration will increase the price at which a QF must sell in order to be able to attract financing, all else equal. If the price at which a QF must sell is in excess of the rate that reflects the utility's then avoided cost, then the QF will not be developed.

Q. **CAN QFS SET THE PRICE AT WHICH THEY MAKE SALES TO THE UTILITIES?**

A. No. QFs are price takers. They receive avoided cost pricing from utilities. They cannot choose the price at which they sell. However, they can choose whether they develop new facilities, and they will do that based on the price they require in order to be viable (*i.e.*, have a reasonable opportunity to attract capital from potential investors). This price is in turn based upon their costs.

Reducing the PPA term and including 2-year energy price resets raises the $/kWh price that a QF requires to be viable for two reasons: 1) the QF's cost of capital will increase as its investors bear more risk; and 2) as a practical matter, investors will seek shorter amortization periods for capital investments, which in turn translate to higher short-term cash flow requirements.

Hence, reducing the term of the PPA increases the near-term costs for the QF, decreases the possibility that those costs could be recovered under avoided cost pricing, and reduces the likelihood that the QF will be developed.

This could easily be the case <u>not</u> because a QF is more expensive relative to alternative resource options when compared on an apples-to-apples basis (*e.g.*, levelized $/kWh cost over the facilities' useful life), but rather because the institutional and market framework for QFs operating in North Carolina includes PPA terms that are too short to allow reasonable access to capital.

Q. WHY DOES REDUCING THE TERM OF THE PPA MEAN THAT QFS WILL NEED TO RECEIVE HIGHER PER KWH PRICES?

A. The shorter PPA gives the QF less time to recover its capital investment. The compression of the capital repayment schedule, in turn, pushes up the price that the QFs must be paid in order to be solvent in the years over which the PPA applies and debt would typically be serviced.

Q. BUT THE INVESTORS IN QUALIFYING FACILITIES MUST RECOGNIZE THE RESIDUAL VALUE OF THE FACILITY BEYOND THE PPA TERM. DO THEY NOT?

A. Equity investors may count on a certain amount of residual value after the PPA term. But that does not mean that they will be willing to accept a large share of unrecovered capital at the end of the PPA. Forcing too much of the capital recovery into an uncertain post-PPA term will undermine the attractiveness of the investment opportunity to equity investors.

Q. HOW WILL LENDERS VIEW PPA ENERGY PRICING THAT RESETS EVERY TWO YEARS?

A. Lenders typically rely upon fixed pricing for assurance that the project will be in a position to service its debt. Lenders evaluate various credit metrics that depend on the projected cash flows, which in turn are driven by revenue, based upon the projected output of the generating facility and the fixed prices for the electrical output. The proposed reduction of the time period over which fixed rates apply will lead to lenders to view the effective PPA coverage period as only two years, even though Duke is proposing a ten-year PPA term. Lenders will significantly discount the revenues available beyond that two-year period. Because of the discounting of revenues beyond the second year, it is unlikely that project debt could be obtained in reasonable quantities for terms longer than two (2) years. In contrast, if the energy pricing were fixed for the entire period of the PPA term, that level of discounting would not occur and higher debt levels could be used to finance the project.

Q. CAN THE QF DEVELOPER SOLVE SOME OF THESE PROBLEMS BY CONTRIBUTING MORE EQUITY?

A. In principle, the developer could contribute more equity. At the extreme end of the spectrum, the developer could contribute the entirety of funds needed to construct the facility. In practice, however, it is unlikely that the project sponsor or other equity investors would be willing to provide equity in such large quantities required to make the project viable in such a context. Equity investors in power projects are often capital constrained and seek to employ debt leverage as part of attractive financial structures and to be able to offer lower prices. From their perspective, the equity investors will be taking on all of the risks of the project but the return available to do so would be lower than the expected return on the traditional structure with long-term debt. While the unleveraged equity investment carries less financial risk, all else equal, it may not offer a return high enough to make the project attractive to an equity provider. This is accentuated by the fact that an equity investor would require higher returns, all things equal, with two-year PPA energy price resets as compared to energy prices fixed for the term of a PPA. Equity investors, like lenders as discussed above, would view the two-year resets as adding significant risk to the cash flows from the investment. This in turn would drive up the cost of financing.

Q. YOU MENTIONED COMPRESSION OF THE CAPITAL REPAYMENT PERIOD FOR QFS WITH SHORTER-TERM PPAS. FOR COMPARISON PURPOSES, WHAT CAPITAL REPAYMENT SCHEDULES DOES DUKE USE FOR ITS REGULATED GENERATION ASSETS?

A. For several out-of-state solar projects, Duke has relied upon a useful life of 30 years with a corresponding depreciation rate of 3.33 percent.[5] For a

[5] Joint Stipulation and Settlement Agreement, Cause No. 44734. Indiana Utility Regulatory Commission, dated April 15, 2016; Petition For Approval Of Depreciation Rates For Solar Photovoltaic Generating Units, Duke Energy Florida, LLC, Florida Public Service Commission Docket No. 160017-EI. January 11, 2016.

OFFICIAL COPY May 05 2017

recent combined heat and power project in North Carolina, Duke sought approval of a useful life of 35 years.[6] For coal facilities subject to regulation by this Commission, I understand Duke uses a 60-year useful life, and a 40-year useful life for natural gas facilities subject to regulation by the Commission.[7]

The point here is that Duke itself uses relatively long capital recovery periods for its long-lived generation assets, yet is proposing changes that reduce capital recovery periods for QFs to unreasonably short periods given the useful lives of such generating assets.

Q. WHAT DO YOU MAKE OF THE UTILITIES' PROPOSAL TO LOWER THE PROJECT SIZE TO WHICH THE STANDARD OFFER PPA WILL BE AVAILABLE?

A. My expectation is that the smaller facilities are those that naturally have more difficulties in obtaining financing. This is why, for example, one sometimes observes pools of small projects being financed together as a group. The reduction in eligibility threshold for the Standard Offer should be expected to further challenge the financing prospects for QFs.

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6 Application of Duke Energy Progress, LLC for Certificate of Public Convenience and Necessity to Construct 21 MW Combined Heat and Power Facility at Duke University, N.C.U.C. Docket No. E-7, Sub 1122, October 17, 2016.

7 Christopher J. Ayers, Executive Director, NCUC Public Staff, Ratemaking Presentation, available at: http://epic.uncc.edu/sites/epic.uncc.edu/files/media/Ratemaking%20presentation%20EPIC.pdf.

Q. IS YOUR ANALYSIS LIMITED TO SOLAR QFS?

A. No. My analysis is not limited to solar QFs. While each technology has its own economics, the principles I have outlined above are general and not specific to a given type of generating technology.

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE EFFECTS OF THE PROPOSED PPA CHANGES?

A. Yes, I prepared Exhibit 3 and Exhibit 4 to illustrate my analysis. Exhibit 3 depicts how the Utilities' proposals will shift more risk to QFs and shorten the time period during which they can expect a stable revenue stream, thereby compromising their ability to obtain financing on reasonable terms. Exhibit 4 provides an illustration of how the Utilities' proposals will change the economics of a QF investment relative to a forecasted avoided cost rate. Together, these exhibits show how the proposed changes to the terms and conditions of the Standard Offer will unreasonably limit QFs' access to capital

Q. PLEASE EXPLAIN EXHIBIT 3 IN MORE DETAIL.

A. Exhibit 3 visually depicts two of the proposed changes to the Standard Offer that are before this Commission. For a hypothetical facility with a 30-year useful life, Exhibit 3 shows the revenue streams that would be available to QFs under several PPA constructs. For the existing Standard Offer PPA construct, investors can count on contracted revenues for 15 years to support investments in new facilities. Reducing the PPA term from 15 years to 10 years reduces by one third the period during which investors can count on stable revenues. Grafting onto a 10-year PPA the proposed two-year energy price reset leads to a situation where lenders and equity investors will only be able to count on two (2) years of known energy revenues during the facility's 30-year useful life. All energy revenues after the second year will be regarded by lenders and equity sponsors as risky and will be discounted accordingly.

Q. WHAT DOES EXHIBIT 4 ILLUSTRATE?

A. Exhibit 4 extends the concepts advanced in my testimony and highlighted in Exhibit 3. Using hypothetical assumptions for a new QF—including the unit size, construction cost, debt and equity ratios, tax depreciation schedule, applicable tax rates, inflation, and costs of capital—I estimate the annual revenue requirement that would be necessary for a QF to cover its fixed capital investment costs. Using the unit's capacity factor, I then calculate the levelized cost of energy over the term of the Standard Offer PPA necessary to recover fixed capital investment costs. First, I make the levelized cost calculation assuming the existing 15-year term available to QFs. Second, I make the levelized cost calculation using the 10-year term proposed by the Utilities. Third, I calculate the levelized cost with both the 10-year term and two-year energy price resets. As these figures are illustrative, and not intended to represent actual QF costs, I present them on a relative basis as compared to the per kWh revenue requirement under the *status quo* Standard Offer. This analysis shows that decreasing the Standard Offer PPA term and implementing two-year energy price resets will increase the revenue requirement of QFs, all else equal. The higher revenue requirement calculated for the shorter PPA term reflects compressed recovery of capital investment, while the higher revenue requirement calculated for the PPA with two-year energy price resets reflects increased price uncertainty and greater discounting of expected revenues.

Q. WHAT IS THE DIFFERENCE BETWEEN THE FIRST AND SECOND CHART IN <u>EXHIBIT 4</u>?

A. <u>Exhibit 4</u> contains two charts because I illustrate the QF economics using two scenarios: in the first, no residual value is attributed to the post-PPA term (first chart); in the second, a residual value equal to 30 percent of the initial facility investment is attributed to the post-PPA term (second chart). While many QF investors will be unwilling to count on 30 percent of the capital recovery occurring after the term of the initial PPA, I present this scenario to illustrate that the Utilities' proposals could also render infeasible QFs that are willing to accept high levels of equity investment risk.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, Strunk Exhibits 1 through 4 were identified as premarked and admitted into evidence.)

CHAIRMAN FINLEY: Anything else?

(No response.)

CHAIRMAN FINLEY: All right. I think the Dominion Panel is available for cross examination.

BRUCE E. PETRIE AND J. SCOTT GASKILL;

Having been previously sworn,
Testified as follows:

CROSS EXAMINATION BY MS. MITCHELL:

Q Good morning, Mr. Petrie. Charlotte Mitchell.

A (Petrie) Good morning.

Q How are you this morning?

A I'm good. Thank you.

Q Mr. Petrie, I'm going to start with your direct testimony.

A Okay.

Q On page 2, line 19, through page 3, line 4, you discuss in general Dominion's commitments to solar QF developers in service in its -- in its service territory and the fact that Dominion is overpaying for -- for the power received from those QFs at this time; is that correct?

A That's right.

Q Okay. And you specifically state that this amount exceeds Dominion's avoided cost for energy and capacity by $381 million; is that correct?

A I'm looking at page 3, "...this amount significantly exceeds the current and projected market value of these contracts by approximately $381 million..."

Q Okay. Thank you.

A Yeah.

Q Mr. Petrie, will you explain just very briefly how you calculated the $381 million?

A Sure. On page -- on page 5 of my direct testimony there's a graph that shows the prices that we -- that we contracted under in Sub 136 and 140. So in the 136 contracts, those -- the all-in price is approximately $72 per megawatt hour, and for the Sub 140 rates it's about $61 a megawatt hour. The yellow line shows our current estimate of avoided cost, so what it is, it's the forward price of electricity on peak, plus -- plus the estimated capacity value. In Year 3 -- in Year 4 you can see the bump up in the curve, so we added an estimate of capacity value. So the way the $381 million is calculated, it's the year by year -- each year

I calculated the difference in price between the QF contracted price, minus the estimate avoided cost, times the production volumes from the QF for that year, and sum that up over the -- over the 15 years.

Q Okay. Thank you. And -- and to be clear, the 381 million represents overpayment to QFs that are in service, as well as QFs for which a legally enforceable obligation has been established?

A Correct.

Q Okay.

A It's the ones online, plus the ones we expect to come online --

Q Okay.

A -- for the -- for the total of 680 megawatts or so.

Q Okay. Thank you. Turning to page 14 of your direct testimony, on line 3 you make the point that Dominion's 2016 IRP which was filed in April of 2016 shows the first capacity need occurring in 2022; is that correct?

A That's right.

Q Okay. And that -- you go on to testify that using the updated load forecast for PJM as of December 2016, the need for incremental capacity is pushed to

2024; is that correct?

A It's not PJM's forecast; it's our internal load forecast. So in the 2016 IRP, when you look at that, the first resource need is in 2022. Using the updated load forecast just to give people a general direction of where the load forecast is going and economic activity, the resource need is -- is pushed out then to 2024, but it's the Company's internal load forecast, not -- I think you said PJM.

Q I did.

A Yeah.

Q Thank you for clarifying that. And then -- and then turning to page 15 on lines 1 through 3, you then testify that using the most recent PJM load forecast which is dated twenty seven -- January 2017, that forecast indicates that a capacity need does not arise until 2026; is that correct?

A That -- that's correct.

Q So that's using a PJM load forecast, then?

A Looking at the PJM load forecast.

Q Okay. Can you explain the difference between the internal load forecast and PJM load forecast?

A I'm -- I'm the user of the load forecast. I'm not the load forecasting expert. I don't -- I can't really say that -- that I'm qualified to explain even at a high level what -- what those differences are. Those types of issues get aired out in the IRP hearing with the -- with the load forecasting expert.

Q Okay. Understood. Can you tell me at a very general level, are those two forecasts usually significantly different? Are they similar? I understand that you are not the expert on this issue, but just do you have a general sense of the difference between the internal forecast and the PJM forecast?

A They're -- well, they're never the same. There's always -- there's always some amount of differences. My recollection is that historically the -- no, I can't even say that. I was going to make a characterization of which one was higher than the other, but I -- I don't even -- I don't want to speculate on that.

Q Okay. Thank you. Okay. Mr. Petrie, just quickly turning to page 26 of your rebuttal testimony, lines 22 through 29, you testify that there is "...historical precedent for the utility to pay zero for capacity during the front years of the contract..." Is that correct?

A That's right.

Q And you cite to the 1994, 1996, and 1998 biennial avoided cost proceedings as instances in which the Commission has recognized that no capacity credit should be included in the capacity rates where there are -- where no capacity costs are avoided; is that correct?

A That's right.

Q Okay. Do you recall, Mr. Petrie, whether for the purposes of the 1994, 1996, and 1998 biennial avoided cost proceedings Dominion used the peaker methodology when calculating its avoided cost?

A Yes. We'd just adopted the peaker method in 2012, in that docket, so back in the mid '90s, in '94, 1996, and 1998, we would have been using the differential revenue requirement method.

Q Okay. Thank you.

A I would like to add, though, that even under that method, that it really shouldn't matter whether -- which method you use, whether it's DRR or the peaker method. If you don't have a need for capacity, there -- we shouldn't have to pay for the capacity in the years that there's not a demonstrated need.

Q Okay. Thank you, Mr. Petrie. Sticking with your rebuttal testimony, Mr. Petrie, is it an accurate characterization to say that you criticize NCSEA Witness

Dr. Ben Johnson's benchmarking comparisons, where he compares the cost of various types of generating technology to the avoided cost rates that the Utilities have been paying in recent years to QFs?
A Yes. I mention that on page 7.
Q Okay. And do you agree, Mr. Petrie, that the objective of PURPA and its implementing regulations is to leave the ratepayer indifferent as to whether the Utility purchases power from a QF or generates power on its own or purchases power elsewhere?
A That's -- that's my understanding of what the words say.
Q Okay. And do you agree that there are three methods that have historically been relied upon or used for calculating avoided cost, which are the peaker method, the proxy method, and DRR which you've just described?
A Yeah. I agree with that.
Q Okay. And do you agree that each of these methods is intended to answer the same question, which is what are the Utility's avoided cost?
A I agree with that, yeah. It's three different methods, all for the same purpose, how to -- how to get a reasonable estimate of what the future avoided cost might

be.

Q Okay. Thank you. And do you recall whether Dr. Johnson recommends that the Commission adopt the proxy method for purposes of calculating avoided cost in North Carolina?

A I think he said he doesn't -- I think he said he's proposing -- he's not proposing to adopt the proxy method. I think that's what he said.

Q Okay. Thank you. And do you agree that this Commission has recognized in past orders that when applying the peaker method, the cost of a hypothetical CT, together with the marginal system running cost, should equal the cost of any generating plant, including a baseload plant?

A Yeah. That's what -- that's the way we've been looking at it.

Q Okay. Thank you. Okay. Mr. Petrie, looking at page 18 of your rebuttal testimony, on page 18 you testify that Dominion's proposal is "...to move more QFs towards non-standard contracts by reducing the size threshold for the standard offer..." Is that correct?

A Which -- which line is that at?

Q I'm sorry. I'm -- it's page 18 of your direct testimony. I'm sorry, Mr. Petrie.

Well, let me restate the question. In general, is Dominion proposing to reduce the standard offer from 5 megawatts to 1 megawatt?

A Yes.

Q And in general, is Dominion -- Dominion's justification for doing so to be in a position of negotiating contracts with QFs as opposed to providing QFs a standardized contract?

A By -- well, by dropping -- I'm not sure if I'm the right person to answer that or you are (indicating Mr. Gaskill). By dropping the size threshold to 1 megawatt, we're -- what we're -- the goal is to help improve some of these price staleness issues that we've had so that by having more of the larger -- or the negotiated contracts, at least the pricing would be more up to date and less stale than what we've seen for the standard offer contracts. I don't know if that answers your question or not.

Q It answers my question. And hasn't Dominion also proposed to adjust rates for larger QFs based on the location of those QFs?

A For the larger QFs?

Q Yes.

A Yes.

Q Okay. And is it true that rates for larger QFs would also be based on avoided cost data that is closer in time to the legally enforceable obligation for such QF?

A That's -- that's the goal.

Q Okay. Mr. Petrie, is it true that Dominion hasn't proposed a specific method for adjusting rates paid to larger QFs for the location of that QF?

A Not a specific -- not specific details about how -- about that pricing.

Q Okay. Thank you. So Mr. Petrie, just following up on that question, is Dominion asking the Commission for discretion in developing the methods by which rates for large QFs will be calculated?

A Well, yeah. The pricing for the larger QFs would be -- it would be more up to date than the pricing would be as of the LEO date. We would look at other particulars as far as that unique -- as far as that location goes, what the LMPs would be at that location. We would look at the amount of load at that location, whether -- whether there is -- how much load there is to offset at that location, and that would -- that would weigh into, for instance, the PAF. I don't know if you want to say anything else about that (to Mr. Gaskill)?

A (Gaskill) Yeah. I would just add a couple of things. So -- so there's kind of two main components here when we're talking about locational for the large QFs. One is the LMP. So what we've proposed here and for the standard contracts is an average of the LMPs across -- across the North Carolina service territory, and we looked at a three-year historical average relative to the DOM zone. So I think that process would stay the same for large QFs except that it would be -- instead of an average across the territory, it would be looking at the node where they're actually interconnecting, but I think we've got -- there's ample historical data, publically available PJM website, so I think that would be the metric we would use for the LMP adjustment.

In terms of the line losses, we can look at that -- the characteristics of that specific line, that circuit, to look at where they're interconnecting on that circuit. I think there was a discovery response, I believe, to Public Staff from our -- from our distribution side as far as how those studies would be done. You look at, you know, a model with and without that QF generation on there and you can estimate the differences in line losses. So we would use studies like that to estimate what the avoided line losses are on that particular QF interconnection.

Q Okay.

A So I think had we proposed a specific, probably not, but I think it would be consistent with what -- what we're offering, the calculation in the standard contract but for that specific location.

Q Okay. Mr. Gaskill -- Mr. Petrie, I have nothing further for you. Mr. Gaskill, I'll go ahead and start with you --

A Sure.

Q -- and just following up on the question that you just responded to. So is it Dominion's proposal, then, that the methodologies for large QFs and small QFs would be consistent other than as you've just testified, which is that the LMPs for the larger QFs would be specific to the node?

A Yeah. I mean, there's different -- I mean, the rates we calculate for the large QFs are still based on the peaker method, so on and so forth, so...

Q So they would -- so the methodology would be consistent other than as you've just testified?

A Yes.

Q Okay. Thank you. Okay. Mr. Gaskill, I have an exhibit I'd like to share with you.

MS. MITCHELL: And just in the interest of -- yes, sir. And in the interest of moving forward, Mr. Chairman, I shared this exhibit with Mr. Gaskill and his counsel in advance, but I'd like to have this exhibit marked as NCSEA DNCP Cross Exhibit 1.

CHAIRMAN FINLEY: It shall be so marked.

(Whereupon, NCSEA DNCP Cross Exhibit 1 was marked for identification.)

Q So Mr. Gaskill, in your testimony you present several different numbers related to levels of QF development in North Carolina, specifically solar QF development in North Carolina; is that correct?

A (Gaskill) Yes, ma'am.

Q And in the interest of clarifying how much solar QF capacity is installed and how much may be installed in the future, I want to walk through these numbers with you now. I've passed out an exhibit which -- which I developed using the queue report that Dominion filed in Docket No. E-100, Sub 101A in February of this year. And my understanding is that this represents your interconnection queue, Dominion's interconnection queue, as of January 30th, 2017?

A Yes. That's my understanding.

Q Okay. And just so the record is clear, I have sorted this spreadsheet, the interconnection report, by Status Description, which is the column on the far right, such that we see all of the projects that are indicated as being canceled, then all of the projects that are being -- that are indicated as being connected, and then all of the projects for which an Interconnection Agreement has been executed, and then those projects which I understand to be under study. And then also to the right of the Status Description column I have provided a total capacity number for each of those Status Description categories.

A Okay. Can I just clarify one thing, I mean, just before we go into this? So --

Q Sure.

A So this does come from our interconnection department, you know, the wires have -- due to the, you know, FERC separation of Code of Conduct? You know, so these aren't my numbers, but --

Q Understood.

A -- but yeah.

Q Thank you for the clarification. Understood. Okay. So on your direct testimony, pages 8 and 9, you explain that Dominion has entered into 72 PPAs representing 500 megawatts of solar capacity; is that correct?

A That's correct. And to date, that is 76 PPAs with 721.

Q 721 megawatts?

A That's right.

Q As of today?

A Yeah.

Q Okay. Thank you.

A Or as of yesterday.

Q Okay.

A It changes every day.

Q Thank you. And you indicate that approximately 350 megawatts have commenced operation; is that correct?

A Yes, as of -- I think that number is now 380 or so.

Q Okay. And that 150 megawatts are under various stages of development, correct?

A That's correct.

Q And by various stages of development, do you mean that these QFs have executed an Interconnection Agreement?

A That's certainly one -- one piece of it. And when I say -- I was speaking more broadly. They're getting their permitting, they're getting their

Interconnection Agreement, they're under various stages, so they haven't actually come online --

Q Oh.

A -- but they could be at various -- various places in --

Q Okay.

A -- bringing that project to fruition.

Q Okay. So they could have an Interconnection Agreement or not; is that a fair characterization?

A Yeah. Could be, yes.

Q Okay. And then on page 9, Mr. Gaskill, line 2, you testify that there are approximately 1,000 megawatts of solar capacity in various stages in the North Carolina distribution queue; is that correct?

A That's correct.

Q Okay. So looking at Figure 2 of your testimony on page 9, Figure 2 depicts that there are 435 megawatts of solar capacity that's operational; is that correct?

A That is correct.

Q And so looking at -- back at the queue report, which is the -- the cross examination exhibit I've handed you, the queue report indicates that there are 435 megawatts that are operational. So can you explain where the additional 90 megawatts comes from?

A Yeah. So to -- I think you stated the queue report shows 345.

Q Okay.

A The -- my Figure 2 shows 435. I believe -- so, again, these are the -- from the interconnection. So Figure 2, I also got those numbers from them. I believe the difference, subject to check, is that there's 90 megawatts that are actually in the PJM queue, but are being -- they're still connecting at distribution level. So I think that's where the other 90 megawatts are. So they're still connecting on our distribution lines, but they're in the whole--- they're going to be selling to wholesale, as opposed to QF selling to us.

And I think that's consistent because if you add your -- in looking at the interconnection queue, the 345 plus the 173 there below, or 174, so that's 519. That's right on top of the number that we have executed PPAs when I said 521. So my best guess is that through your numbers or the -- not your numbers, the interconnection queue numbers, 345 plus 174, those are in the state queue, meaning they're primarily QFs, probably all QFs, whereas the other 90 are in the wholesale queue, but still being connected at distribution.

Q Okay.

A I believe that's the difference.

Q Okay. Thank you. Okay, Mr. Gaskill, Figure 2 also represents or depicts that there are 363 megawatts of solar capacity in the study phase. And looking back at the exhibit, for those projects that are -- for which the status description is indicated as Project A, Project B or Subordinate, are those projects that are in the study phase?

A I'm not -- I'm not sure how the characterization would cross between these numbers.

Q Okay.

A My guess, there may be different -- again, there may be some numbers in that 363 that are in the wholesale queue, maybe that could be the difference. I'm not entirely sure.

Q Okay. And just to be clear, the wholesale queue, are those QFs that will sell into wholesale, as opposed to selling to DNCP?

A That's correct.

Q Okay.

A But they would still be connected at distribution level or they can also be at transmission level. And that's -- if you look at -- on page 9, my Footnote 1, I note that there's another 1,800 megawatts of active projects in the PJM queue. That would be at transmission level.

Q Okay. Thank you. So just to be -- just to be clear, there -- if a project is interconnected with Dominion at the distribution level, it can still sell into PJM at wholesale?

A If it's a non-QF. If there are QFs selling to us, they're obviously not making a wholesale sale.

Q Understood.

A But they have access to the wholesale market, whether they're at distribution or transmission level and are in our territory.

Q Okay. And so some of the numbers in your testimony reflect QFs that are interconnected at distribution level, but that are selling into PJM?

A Some of those. The majority are QFs, but --

Q Okay.

A -- but there are some.

Q Okay. Thank you. Mr. Gaskill, in terms of state jurisdictional solar QFs, so QFs that are selling to DNCP, would you agree that the queue report indicates that there are seven large QFs? So by large QF, I mean a QF that's in excess of 5 megawatts?

A That are already completed or just total?

Q Yes. That are connected, that are identified as connected.

MS. KELLS: Counsel, can you direct him to -- there's a lot of lines on here.

MS. MITCHELL: Yes.

Q So for those -- for those projects that are identified as being connected on the exhibit --

A Right.

Q -- would you agree, subject to check, that seven of those projects are greater than 5 megawatts?

A That appears correct, yes.

Q And that the remaining projects would be 5 megawatts or smaller?

A Yeah. Most of them right at 5.0.

Q Okay. And do you -- Mr. Gaskill, do you know generally or roughly how many of those QFs are owned by Duke Energy?

A Of those seven?

Q Of the state jurisdictional QFs identified as being connected.

A Duke Energy Renewables --

Q Yes, sir.

A -- their merchant arm. I don't know how many are connected or how many are still under status. I believe roughly 15 or so.

Q Okay. Thank you.

A Eighteen, maybe, somewhere in there.

Q Okay. Thank you.

CHAIRMAN FINLEY: Did you say 15 or 18?

MR. GASKILL: Yeah. I think it's 18, actually.

Q Okay.

A And I don't know how many of those are operational or still under development.

Q Understood. Thank you. Okay. Mr. Gaskill, turning to page 13 of your direct testimony --

A I'm sorry. What page?

Q Page 13, lines 12 through 16. Generally, you testify that "...the prior avoided cost rates approved by the Commission have" -- exceeded -- "have succeeded in encouraging QF development." Is that correct?

A Yes.

Q And you go on to testify that encouragement has come at a cost to Dominion's customers; is that a --

A Yeah.

Q -- fair characterization?

A That's what my testimony says.

Q Okay. And then on page 30 of your direct testimony, lines 8 through 19, you testify in general that the consequence of a mismatch between market energy costs and locked in avoided cost contract rates is that Dominion and its customers are overpaying under these contracts?

A Yeah. What the -- the point I'm making here, and if you refer to the question in line 5, how do shorter contracts mitigate customer risk, and so that's -- that's the point of the proposal we're making to shorten the standard offer contract when you go from a 15-year to a 10-year term, you're -- we still have an obligation to purchase after the end of that contract, but you have a more frequent reset of avoided cost pricing so it ensures that that overpayment or underpayment stays in line with the actual avoided cost.

Q Okay. Understood. Thank you. As I -- as I understand Dominion's position, as stated in your testimony, because fuel prices and power prices have declined since the rates that Dominion is currently paying to QFs were established, those contracts are an uneconomic burden to your customers; is that a fair characterization?

A They're a burden in the sense that we are paying more for those contracts than the cost that we're actually avoiding. We could get that energy and capacity cheaper at current market prices.

Q Okay. Understood. So using the logic underlying this position, couldn't the argument be made that any generation that's built based on forecasts that change subsequent to the -- the date on which the investment decision is made could be an uneconomic burden to customers?

A It could be, but the difference is when we go in to build, whether it's, you know, a CPCN proceeding, we're running price sensitivities, we're looking at various cases and we're -- we're looking at -- obviously, we have an obligation to meet energy and capacity needs going forward so you look at that. So you have to build or purchase something, and we do. We don't have a choice. I mean, we have to -- have to build or buy something. So what you're doing is looking at what is the least cost plan to do that taking into account fuel diversity and a host of other factors, but -- so when we make an investment decision and it is approved by the Commission, we're doing so at a price that's below avoided cost, I mean, below our projected market price, or else you wouldn't build.

Q Understood. But isn't it true that conditions can change, that fuel forecasts that were in effect at the time the decision is made could change?

A Yes. Forecasts do change, yes.

Q And I'm -- and I want to be clear, I'm not -- I'm distinguishing between -- I'm not asking you about prudence. I'm just asking you about simple, you know, weather economics.

A Right.

Q Okay. Okay. Just a few more, Mr. Gaskill. And you've actually already answered these questions so I have nothing further.

CROSS EXAMINATION BY MR. STEIN:

Q Good morning, Mr. Gaskill. Peter Stein for Southern Alliance for Clean Energy.

A Good morning.

Q Just a few questions for you this morning. Mr. Gaskill, in your testimony you discuss Dominion's proposal to eliminate the 3 percent line loss adder for QFs that sell their output under the standard offer contract, correct?

A Yes, sir.

Q And the Company's proposal is based on your assertion that with -- higher penetrations of solar backflow is taking place on a greater number of circuits; is that correct?

A Yeah. What line -- what page and line number, just so I can refer?

Q Sure. At page 22 of your direct testimony. And the section of this discussion begins on page 20.

A Right. So -- so what I'm saying, so we've reached a point where on the majority of the circuits where QFs are actually interconnecting there -- there either is or will be reverse flow on that circuit. So avoided line losses occur when -- when you have a distribution level QF and it's actually avoiding having to transmit generation from the -- from essentially planned generation across the transmission line through the transformer to the load, they can avoid that. But if it's not actually serving the load on that circuit, it's reverse flowing, then line losses are no longer avoided and, in fact, in many cases, can be -- can add to line losses.

Q Okay. But that doesn't mean that in the future there will never be line loss reductions associated with future QFs; is that correct?

A For the foreseeable future, I -- you know, there would have to be a lot of load growth in a pretty short amount of time for QFs interconnecting in this docket to actually be avoiding line losses. I don't foresee that happening.

Q But they -- they won't be zero; is that a fair characterization?

A I think on average they would be zero or even contributing to more line losses.

Q Okay. In your testimony has the Company measured those line losses or quantified that?

A Which line losses?

Q Current line losses for -- for QFs on the grid.

A So it obviously varies by line, by QF --

Q Okay.

A -- depending on the load conditions of that circuit. So we're saying it's -- on average, across the -- across the territory here there would be no more line losses avoided.

Q Thank you. Over the past two years has -- has the Company quantified line losses associated with QFs in times when backflow was and was not occurring?

A I know there are some studies going on. There's a solar partnership program study where they are looking at QFs that are specifically put on high loaded circuit and low loaded circuit. I'm not -- I'm not intimately involved in that study. I'm generally familiar, but -- so I know there are studies going on.

Q Okay.

MR. STEIN: Mr. Chairman, I have a document that I'd like to share with the witness.

CHAIRMAN FINLEY: Go right ahead. You may approach.

Q Mr. Gaskill, just let me know when you've had a moment to review.

A Okay.

Q Okay.

MS. KELLS: And, counsel, I just want to make clear this was a different Dominion personnel's discovery response, so Mr. Gaskill can answer to the extent he's able.

MR. STEIN: Understood. Thank you.

Q Mr. Gaskill, in the question itself, third line down reads, "Has Dominion quantified system losses associated with QFs in its North Carolina territory during times when backflow was and was not occurring over the past two years?" And the Company's response was, "No." Is that correct?

A Right, with -- with an explanation bullet.

Q Thank you. And Mr. Gaskill, looking at your direct testimony again, you describe that the Company could calculate line losses for QFs that are negotiating a contract; is that right? And I can refer you to page 22, lines 15 through 19, that it is, in fact, possible to calculate the specific line losses avoided by a specific QF. Is that a fair characterization?

A It says the Company may calculate a specific loss percentage, either positive or negative, depending on each project specific interconnection location.

Q Okay. So it would be possible for future QFs taking service -- or I'm sorry -- selling their output through the standard offer, it would be possible for the Company to calculate the line losses, any line loss avoidance caused by those future QFs, correct?

A Well, for the -- and you referred to the standard offer instead of the negotiated?

Q For either. For any QF.

A Well -- well, for the -- I think it would be possible, certainly, for the non-standard offer when we're looking at that specific QF, I mean for the standard offer because it's one contract that's available to -- to everyone, you know, then what we're trying to do is come up with kind of what is the average line loss across the service territory. And that's where we've arrived at -- it could actually be positive, but we propose zero.

Q Okay. But that's not based on a specific quantification; is that correct?

A That -- that's right, because it can't be QF specific when we're talking about the standard offer.

Q Okay. Thank you, Mr. Gaskill.

CROSS EXAMINATION BY MS. BOWEN:

Q Mr. Petrie, I have some questions for you. I'm Lauren Bowen here on behalf of Southern Alliance for Clean Energy. Good morning.

A (Mr. Petrie) Good morning.

Q Mr. Petrie, does the Company enter into contracts for capacity outside of QF agreements?

A Occasionally.

Q And the Company recently had a capacity need related to the deactivation of the Roanoke Valley Power facility from PJM on March 1st of 2017; is that correct?

A That's my understanding, yeah.

Q And the Company has been filling some of that need through short-term capacity purchases in the PJM market; is that correct?

A Yeah. Mr. Gaskill's going to help me out here.

A (Mr. Gaskill) Right. So that Roanoke contract falls under my -- under the power contract. So, yeah, that -- so that was a contract, that unit, a contract went through mid-year 2019. It had been committed into the PJM auction, the capacity performance marker, restructuring that contract, so they deactivated that unit and we had to procure replacement capacity, capacity performance, capacity through the end of the -- what it was committed to in PJM.

Q And that was through 2019, if I remember correctly?

A Through the PJM delivery year, which would have -- it was committed in PJM through May 31, 2019.

Q Okay. Thank you. And -- and then the Company is self-supplying the rest of that capacity; is that right?

A A portion of it, yes.

Q Okay. Thank you. Back to Mr. Petrie, I believe this is for you. The Company has several solar photovoltaic generators in its rate base; is that correct?

A (Mr. Petrie) That's right.

Q And that includes Scott 1 Solar, Whitehouse Solar and Woodland Solar, if you recall?

A Correct. Yeah.

Q Okay. And what is the depreciation length for those projects that are in rate base?

A I believe it's 35 years.

Q Mr. Petrie, how many contracts does Dominion have with 5 megawatt and smaller QFs that are less than 15 years?

A I think that's -- Mr. Gaskill's going to...

A (Mr. Gaskill) Please repeat your question.

Q Sure. For QF contracts, how many contracts does Dominion have with 5 megawatt and smaller QFs that are less than 15 years?

A We have a handful that are on the Schedule 19 LMP which doesn't -- which basically doesn't have a -- have a fixed price at all. The remaining would be in 15 year.

Q Okay.

MS. BOWEN: If I may, I'd like to share a document with opposing counsel and the witness.

Q Have you had a chance to review the document?

A Yes.

Q Thank you. And does this appear to be a SACE data response -- excuse me -- a Dominion data response to Southern Alliance for Clean Energy, Data Response 2-27? The question presented is on page 35 of initial comments, "Dominion states that it has signed six solar QF contracts for generators sized 12 to 20 megawatts."

However, for -- the question goes on to ask, "For facilities or generators sized below 5 megawatts or under 1 megawatt, how many 10-year solar QF contracts has Dominion entered into?" And would you mind please just reading the response to those questions below?

A Yeah. "All of the QFs eligible for the standard contract have chosen a 15-year term."

Q Okay. Thank you. That's all I have on that exhibit -- or excuse me -- on that document.

Mr. Petrie, I think back to you again.

A (Petrie) Okay.

Q Mr. Petrie, Dominion engages in joint system planning between North Carolina and Virginia; is that correct?

A That's true.

Q And so that would include Dominion's generation and transmission planning, and that's done on a systemwide basis?

A Right. We do our generation planning for the system as a whole.

Q Okay. Thank you. And then Mr. Petrie, in terms of avoided energy calculations for this proceeding, did Dominion calculate avoided energy using a production cost model?

A Yes. We use the PROMOD model.

Q And did Dominion model the -- with QF scenario to include a 100 megawatt generator with a zero production cost?

A We do.

Q Okay. And then did Dominion's model include that 100 megawatt generator having any outages?

A Yes. That -- in the -- so when we do the avoided energy cost, we run two -- two cases through PROMOD. There's a without case and then we -- we make one change. We add a block of 100 megawatt energy to the case to see -- and then look at the -- how much the production cost goes down by adding that block of free energy. The block of energy that we add is -- it's got an 85 percent availability and the -- it's -- the 15 percent unavailability is spread evenly throughout the year.

Q Spread evenly throughout the year. And so that means all hours of the year; is that right?

A Yes.

Q And so would that include both -- it's all hours of the year, so that would include both off-peak and on-peak hours?

A Yup. Yes.

Q Thank you, Mr. Petrie. And in response to a data request from Southern Alliance for Clean Energy, which I can show you if you need it, but I'd just like to read a clip from that, and let me know if that is accurate and if you'd like to see it.

MS. KELLS: Yes. Could we see it, please? Thank you.

Q Let me know once you've had a chance to look at that. And I can direct you -- I'm only going to ask about G, the response G at the very bottom.

A Right. Okay.

Q Okay. Mr. Petrie, just if you would, please read the response in G.

A "Since no generator is expected to achieve 100 percent availability, the 85 percent availability is representative of a baseload unit. In other words, 15 percent is a reasonable allowance for the unavailability of a baseload generating unit. The 15 percent unavailability is spread evenly across all hours of the year."

Q Thank you, Mr. Petrie.

MS. BOWEN: I have no further questions.

CROSS EXAMINATION BY MS. HARROD:

Q Good morning, Mr. Petrie and Mr. Gaskill.

Jennifer Harrod on behalf of the Attorney General's Office.

A (Gaskill) Good morning.

A (Petrie) Good morning.

Q I think this question is for Mr. Petrie, but tell me if I'm wrong. I'd like to ask about the LMP, the locational marginal price.

A (Petrie) Depends on -- well, yeah. Ask the question and we'll decide who's going to answer.

Q Oh, that's fine. That's fine. Absolutely. I'll ask and you answer. I'd like to know -- Mr. Gaskill testified on page 23, line 5 --

A (Gaskill) We're in the direct?

Q In the direct, correct. "PJM calculates the locational marginal price that reflects the value of energy at each specific node on the grid." My question is how is that calculated? Does that represent actual sales?

A It's representative -- that's a -- that's a -- how long do you have? How LMPs are calculated. It's representative of the marginal price to serve an incremental load at that location. So if you were to add, say, 1 megawatt of load at that location, what take into -- taking into account congestion on the system and marginal losses, real time, what generator in PJM is available, the cheapest generator available, to serve load at that location.

Q Okay. Who are the users of that information? Is that for wholesale sales or who...

A Anybody that's a participant in PJM would use that.

Q Okay.

A So our load is bid in every day into PJM. So we're buying our load at the LMP price, and our generators are selling into PJM and receiving revenue at the LMP.

Q Okay. So somebody in PJM who wants to buy energy in the Dominion zone, the locations in North Carolina are cheaper?

A The LMPs in that part of the DOM zone are lower.

Q I made an assumption. What does DOM zone mean?

A So DOM zone is -- so PJM obviously is 11 different states. It's a big area. So they break it up into transmission zones, so the DOM zone or the Dominion zone.

Q Okay.

A It's not all of Dominion. There are -- ODEC and NCEMC are a part of that, but it's primarily the Virginia and North Carolina piece of PJM.

Q Okay. So on page 23, line 11, you state that LMPs in the Company's service territory have been consistently lower than prices for DOM zone as a whole.

A Right. So the prices in the North Carolina portion of, you know, our service territory tend to be -- and that's where Mr. Petrie is about four and a half percent lower than if you take a weighted -- load weighted average across all of the zone.

Q Okay. And the phraseology there says "consistently lower." Over what time period was that?

A We looked at the last three years --

Q Okay.

A -- on average.

Q So then turning to Figure 3 in Mr. Petrie's testimony, which is on page 10, this figure shows LMPs at six locations, and you said that it was put together using locations that have QF nearby. And just looking at those numbers, I see that the numbers -- the North Carolina locations are 3.5 percent lower in the calendar 2014, they're 4.5 percent lower in calendar 2015, and they're 5.2 percent lower in calendar '16. And my question is, is that -- do you have an explanation for why it's lower and why it keeps getting lower as a percentage value?

A (Petrie) No. I'm not -- I don't think you can really glean anything from that trend. It's some years -- some years the percentage difference is going to be higher, some lower, but what we were trying to demonstrate here is that for the past three years -- well, since early 2014, the LMPs in the North Carolina area have been consistently lower than the DOM zone as a whole.

Q Is that because of greater solar penetration in North Carolina?

A That could certainly be a contributing factor to it.

Q Okay. So -- well, what other factors could contribute to it?

A They -- what -- the LMPs, they give a relative indication of generation versus load in that area. So if there is -- with low LMPs, it generally means there's -- it can mean that there's more generation than load, and we think that's what -- that's part of what's driving these LMPs lower is the existence of these generators on those lines.

A (Gaskill) Yeah. I mean, I would just add, I mean, you look back in the 2014, it's, you know, three and a half percent lower on peak. There wasn't a whole lot of solar generation in the -- in 2014. It's kind of evolved. So it could play a part in it, but it's primarily just congestion on the system and being able to -- the difference between the supply and demand where we have a load in Northern Virginia, Hampton Roads area, that -- versus -- it's supply and demand in the marginal cost at different places.

Q Okay. I have a question for, I believe, Mr. Gaskill referencing page 32, line 11 of your direct testimony. It actually starts at line 11, sorry. While in theory -- and this is talking about -- well, let me just read it. "While in theory the overpayment in the early years of the contract will be negated by the underpayment in the later years, this disparity creates a significant risk for customers that the QF will not perform during the later 'underpayment' portion of the contract." I wanted to ask you about that -- the second part of that sentence, the risk of the QF not performing.

A Okay.

Q Now, is that -- would that be a violation of the PPA for the QF not to perform?

A Not necessarily. If you have degradation of your solar panels over time or you have inverters go out and they don't replace it, there's nothing in the PPA that would be a violation of that. There's no output guarantees or anything like that.

Q Okay. Has that actually happened?

A Well, all of the solar QFs right now under the standard long term, they're all in those front years where you're overpaying, so I would say there's not enough track record here to understand whether that will or won't happen.

Q Okay. And just so I make sure I understand, once the QF facility has been built and it's entered into a PPA with the Company and its sort of fixed costs are sunk, it has every -- am I correct that it has every financial incentive to perform the contract?

A Well, again, if something -- say you're Year 10 of the contract, the inverters go out, panels degradation, it may be -- because we've got a levelized price and those payments are now below market, it may be that there isn't a financial incentive to actually keep -- you know, maintain the unit. So I'm not sure I can answer that.

Q Okay. Well, that's a fair answer. And so one more question, then. Is there another customer for that service? I mean, can they go out and shop it to the highest bidder or must they sell it to Dominion?

A There's a wholesale market. They can get a wholesale market participation agreement and sell it into PJM, yes.

Q Okay. And Mr. Petrie, I would just like to clarify something that you said when Ms. Mitchell was asking you questions about the calculation of the overpayments as Dominion calculates those. And, sorry, I don't recall what page of your testimony it was, but she asked you -- and I just want to make sure I understand. So she asked you is that estimation based on the QFs that are under LEO or based on what Dominion expects, and you said yes, and so I just want to make sure, does every QF under LEO actually come online and provide energy?

A (Petrie) The megawatts that I included, it includes the contract signed under the Sub 136 docket --

Q Uh-huh.

A -- and the 140 docket, so it includes facilities that are already online and ones that are expected to come online.

Q And when you say "expected," does that mean by your own projections or because they have an LEO?

A I believe it's because they already have the

LEO.

Q Okay. And in your experience does every facility come online that has an LEO?

A No. I can't speak to that.

A (Gaskill) Yeah. I mean, the intent of this is the overmarket payments that we are obligated to pay, so whether they come -- they have an LEO, so we have an obligation to purchase their power if they come to fruition. I would agree with you that not every project that has an LEO ultimately gets built, which gets back to our discussions on the LEO and what should or should not constitute an LEO.

Q Okay. Yes. And then just one more question. I would like to understand what the difference is between the standard contract and the negotiated contracts for Dominion. I don't know -- were you all in the hearing room to hear Duke's testimony?

A (Nods affirmatively.)

Q So does Dominion have a standard offer, a standard opening offer, for its negotiated contracts?

A We do, and I would say that's evolved a little bit in -- just to add a little more flavor to that, so obviously there's -- we've got 12 current contracts that are non-standard contracts.

Q Okay.
A Those probably encompass, I want to say, four or five different developers. So obviously some developers have, you know, multiple contracts. So we have a standard opening offer, we do that, but then I think as we've evolved and negotiated with various developers, I'd say we sort of have a, like I say, a standard contract with that developer, if that makes sense. So we kind of work through a lot of the pain points and we've come to an agreement. So then when they come back to a, hey, I've got another non-negotiated, non-standard contract -- so it's sort of a non-standard, standard offer to that particular QF.
Q Okay. What are the lengths of those negotiated contracts?
A They vary.
Q What's the shortest?
A Ten.
Q What's the longest?
A Fifteen.
Q If Dominion -- if the Commission agrees to lower the standard contract to 1 megawatt, will you continue to offer 10-year negotiated contracts to QFs?
A That would -- for now, that's what we are

offering. I mean, I can't say what -- in the future we'd look at conditions where the market is. For right now, that's what our -- that's what our initial offer is to a new QF.

Q Okay. And other than what you've already -- what the two of you have already testified to today, are there other significant differences between the negotiated contracts and the standard offer contract?

A I mean, similar to what -- I believe it was Mr. Freeman yesterday testified to, you know, the -- and maybe Mr. Snider -- I mean, the actual calculation of the rates are still based on the peaker method, same input, same basic methodology. We do a non-levelized instead of levelized pricing. There's, you know, a handful of things like that, but in terms of the actual calculation of the rates, it's not really a different process.

Q I'm sorry. I don't -- when you say non-levelized versus levelized, I don't know what you mean by that.

A Okay. So turn to maybe page 33 of my direct testimony. So there's a Figure 7 there, is -- so you see like the blue line in this example is the annual year-by-year avoided cost rates. I believe this is the energy rates. So under the standard offer, we levelize that, so we would give them -- like that red line, that's a 15-year example. So we levelize that over time. Under the negotiated, non-standard, we typically do an annual, so it's more like the blue line.

Q Every year you reset the avoided cost?

A No. It's calculated up front.

Q Okay, okay, okay. Oh, okay.

A Just the rates change every year --

Q Okay, okay.

A -- in the contract.

Q I understand. I do understand. Okay. Thank you very much.

A And that's because on the larger -- so that way you don't have that overpayment in the early years. It better correlates to your actual avoided cost year to year.

Q I do understand. Okay. Thank you very much.

A So my point is there are some differences but -- in the standard and negotiated.

CHAIRMAN FINLEY: Mr. Dodge?

MR. DODGE: Thank you.

CROSS EXAMINATION BY MR. DODGE:

Q Good morning, Mr. Petrie and Mr. Gaskill.

A (Petrie) Good morning.

Q Tim Dodge with the Public Staff. Actually, Ms. Bowen covered several of the topics that I had planned to ask questions on so I only have a few questions. Mr. Petrie, most of them are going to be directed to you.

And, again, Mr. Petrie, in your capacity at Dominion you are in charge of system planning, the IRP process?

A (Petrie) I'm not in charge of the IRP process. I'm Manager of Generation System Planning.

Q Okay. And while -- you may have indicated earlier you don't make the forecast, but you rely on those in that IRP process, in the planning process?

A That's right.

Q And those are done on a systemwide basis, not just a North Carolina or Virginia basis?

A That's right. And in our modeling we use the system -- system load forecast.

Q Do you have the November 15th, 2016, filing with you there?

A Yes.

Q Could you turn to page 5 of that filing, the Figure 1?

A Okay.

Q And just to be clear, on this chart it shows the QF solar development and the various stages, and Ms. Mitchell went through some of those various stages earlier with you, but the line that's indicated the average on-peak load on that line, that's the average on-peak load for Dominion's North Carolina service territory; is that correct?

A That's right.

Q Okay.

MR. DODGE: Chairman Finley, I have a cross examination exhibit I'd like to distribute.

CHAIRMAN FINLEY: We shall mark this exhibit as Public Staff Gaskill Cross Examination Exhibit Number 1.

(Whereupon, Public Staff Gaskill Cross Examination Exhibit 1 was marked for identification.)

Q And I apologize. Actually, this is labeled for Mr. Gaskill. I was questioning Mr. Petrie, but Mr. Gaskill, you actually are the person who signed the top of this data request as preparing the response?

A (Gaskill) I did, yes.

Q Okay. And subject to check -- or would you confirm that this is a response from Dominion North Carolina Power to a data request from the Public Staff regarding this Figure 1 in the November 15th filing?

A Yes, it is.

Q And in this chart or in this question we asked Dominion to provide a revised Figure 1 using QF generation for Dominion's system, not just the North Carolina portion, along with Dominion's system average on-peak load?

A Yes.

Q And if you turn to the second page, which is the attachment to that response, this shows those same levels of solar generation and the various status, and then the top dash line that's labeled Average On-Peak DOM LSE Load, that's the basis that you would use for system planning; is that correct?

A (Petrie) Yes. That's right.

Q All right. Now, in your -- Mr. Petrie, back to you. In your direct and in your rebuttal testimony, specifically on page 25 of your rebuttal testimony -- I'll give you a moment to turn there.

A Okay.

Q In that section on page 25 you note that Dominion should not be required to pay QFs for capacity during the duration of a standard offer contract based on the assumption that no additional intermittent generation in Northeastern North Carolina will be -- will not allow the Company to avoid or defer future capacity needs; is that correct?

A That's right.

Q Okay. And then you continued on to state that in the alternative, if the Commission declined to accept that position, that Dominion would agree with the Public Staff's conclusion which is in line with Duke's position that it's acceptable, includes zeros in the calculation and capacity rates for the years where the Company's IRP does not show capacity need; is that correct?

A Yes. I'm looking at line 6 here, yeah, so I think that's what you just said, that our -- "DNCP's position remains that no capacity should be paid to QFs in the Company's service area for the duration of the standard offer contract. However, should the Commission decline to accept the Company's proposal not to pay capacity, then, yes, the Company would agree with Mr. Hinton's conclusion..." -- "...that including zeros in the capacity rate calculations in the years prior to the first year of system capacity need is reasonable and appropriate." I think that's what you're --

Q It is. Thank you. Yes. I could have -- I restated it a bit from what was in there. I should have just read directly from it. Thank you. And as you were talking about earlier with Ms. Mitchell, there's -- Dominion has proposed some adjustments in light of the fact that Dominion has identified some location specific concerns with where QFs may be and what those impacts are on their system; is that correct?

A That's correct.

Q And the Public Staff's testimony has indicated agreement with Dominion's location specific adjustment and reduction of the line loss adders for the standard offer contracts based on some of those locational concerns; is that correct?

A Oh, I'm sorry. Could you say that again?

Q So in -- sure, I'll be happy to repeat it. The -- so the Public Staff's position in the testimony they filed on March 28th, and it's in a couple of our witnesses' testimony, but with regard to the LMP adjustment that Dominion proposed, did the Public Staff agree with that adjustment --

A I believe they did.

Q -- for the standard offer contracts? And also the line loss adder adjustment, did the Public Staff agree with that adjustment?

A Right. I believe they've agreed with that, also.

Q Okay. Thank you.

MR. DODGE: I have no further questions.

CHAIRMAN FINLEY: Redirect? Duke?

MR. SOMERS: Thank you, Mr. Chairman. I have just a couple questions.

REDIRECT EXAMINATION BY MR. SOMERS:

Q Mr. Gaskill, I think my questions are for you, but Mr. Petrie, feel free to answer or chime in. Also, again, I'm Bo Somers for Duke Energy. Because of the way I'm sitting, I'm behind you. Don't feel like you have to turn around and hurt your neck. Please don't.

I believe, Mr. Gaskill, you've been -- I believe you testified in your prefiled testimony about the current LEO process or legally enforceable obligation; is that correct?

A (Gaskill) Yes, sir.

Q And would you agree that the current process is not a meaningful determination of when a qualifying facility is ready, willing, and able to commit to sell? Would you agree with that?

A I would agree and, you know, I think as I read, I believe it was Mr. Freeman's testimony, agree with -- you know, there's kind of a couple of issues, one, that they're committing to sell before they have all the information to know whether they're actually -- it's a viable project. You know, they don't have all their costs and that sort of thing. And I think the other issue is particularly on the -- well, really both the standard and non-standard is the amount of time between, you know, that gap, which we discussed yesterday, between establishing an LEO and when the project actually goes under development and comes to fruition.

Q Okay. Thank you. I believe you've been in the hearing room, fortunately or unfortunately, for the past two days while the Duke witnesses were on the stand, and did you -- were you here for Mr. Freeman's testimony, I believe particularly some cross examination questions from Ms. Edmondson, I believe, from the Public Staff, about where Mr. Freeman testified to Duke's belief that tying the LEO to the PPA or the contracting process was a better result? Did you hear that testimony?

A I was here, yes.

Q And on behalf of Dominion, would you -- what is your view of that position that Mr. Freeman expressed and his willingness to work with Dominion and the Public Staff on reaching some agreement on that process?

A Yeah. I appreciate that. Yeah. When I read Mr. Freeman's testimony, I do think something like that in his framework for the PPA negotiating process would be a -- would be a great addition to the process, and I think because it clarifies expectations and requirements for both the QF and the Company in terms of time to go back and forth in the negotiated contract, so I think that would add a lot of clarity to the process. I haven't had a chance to, you know, provide specific inputs to that, but we would welcome the opportunity to participate in that.

Q Thank you. Last question. I believe Ms. Mitchell asked you or Mr. Petrie about whether Duke Energy's unregulated arm owns projects in Dominion's North Carolina service territory. And I'd like to ask, if you're aware, does Dominion's unregulated business also own solar facilities in Duke's North Carolina regulated service territory, if you're aware?

A Not that I am aware.

Q Are you aware that Dominion -- are you aware of whether or not Dominion is actively seeking to acquire solar -- existing solar facilities in Duke's North Carolina service territories?

A I do not know what the -- the non-regulated side --

Q Thank you.

A -- what activity they have going on.

Q Thank you. Mr. Petrie, are you aware of the answer to my questions?

A (Petrie) Yeah. I'm not aware of any -- of what's going on on the unregulated side.

MR. SOMER: Thank you very much. No further questions.

CHAIRMAN FINLEY: Redirect?

MS. KELLS: Yes. Thank you.

REDIRECT EXAMINATION BY MS. KELLS:

Q Mr. Petrie, Ms. Bowen asked you a question about -- I think Mr. Gaskill answered this, too -- about Dominion entering into contracts for capacity outside of the PURPA context. Do you recall --

CHAIRMAN FINLEY: Ms. Kells, pull the mic up, please.

Q I think Ms. Bowen asked you a question about Dominion entering into contracts for capacity outside of the PURPA context. Do you both recall that questioning?

A (Petrie) Right.

A (Gaskill) Yes.

Q I think Mr. Gaskill primarily answered the question, but either of you can answer this. Could you talk a little bit more about why incremental solar located in your North Carolina service area would not be able to defer or avoid the Company's need to purchase or supply that replacement power?

A (Gaskill) Sure. And there's a few reasons, primarily because they are non-wholesale contracts so they are connected at distribution level. They don't have PJM Interconnection Agreements so they're in the state queue. So we can't bid these in directly into the PJM capacity market. So you can't say here's our PJM capacity need, bid them into the capacity performance market and get revenue from that. The way we do get that capacity value in these or can get capacity value from these is over time as they generate and reduce the peak load, then that reduces the amount of time -- the amount of capacity that we have to procure in PJM because our load is going down. So these are load reducers as opposed to PJM generators. So the issue we have here --

Well, let me first say, going back to the question, she asked specifically about that ROVA, trying to replace that capacity. So that was even more specific that, as I said, that unit had been committed -- it's about 220 megawatts or so -- into the three-year forward auction capacity performance auction. So in order to replace that capacity, you have to -- you have to find eligible CP capacity that's available in the market to buy and replace that capacity. So behind the meter solar would not have qualified for that. So it would not have been eligible to replace that capacity.

Over time you can get, like I said, capacity value by reducing your load obligation, the amount we have to purchase, but that's where we get to the point where if it's exceeding our on-peak load in that location, it's no longer actually reducing load. And so if we're looking at getting value for that over time by reducing load and there is no more load to reduce, there's a very limited place to put that capacity.

Q Okay. Thank you. This question, I think, was also in response to a question from Ms. Bowen about the exhibit. This was the discovery response from SACE 2-27 where SACE asked about how many 10-year solar contracts you've entered into with small generators?

A Yes.

Q And your response was that they'd all chosen the 15-year term?

A That's correct.

Q Am I correct in that when you were answering that question, you were speaking in terms of the Schedule 19 FP?

A That's right, I mean, and the question refers to page 35 of the Initial Comments, where we're talking about the QF generation that has come online since 2014. So when I -- that was the context in which I answered that question.

Q Okay. Thank you. Right. And so the others were on the LMP is what you were --

A That's right.

Q Okay. I had a couple follow-ups on the LMP discussion that we've had here. There was some questioning by -- actually, I'm not sure -- it might have been Ms. Mitchell or Ms. Bowen, about Dominion is going -- what you're going to do for standard and non-standard QFs based on location. Can you -- and you were discussing a little bit about the adjustments to the rates you would make for QFs. Can you lay out a little bit more what those appropriate adjustments are in terms of line loss LMPs --

A Sure.

Q -- what it is that you can do?

A Right. So the LMP is one, so I guess we can take that first. So, again, and I -- the actual marginal avoided system cost of that generation, or in this case reducing load, is whatever the marginal cost is at the point in which it's interjecting. That's what our system avoided costs are. So when we look at a specific QF, which we can't do in the standard contract, so we've got to kind of take an average which is what we're doing for the standard. But when we look at a non-standard, we can look at specifically where they're locating and look at what the LMP difference is between that location and the DOM zone. And really what this gets at is our avoided cost when we do -- when Mr. Petrie runs the PROMOD model, he -- that doesn't have the granularity to get the individual location, right? So all we can do is run our whole system as -- I'm going to call it one bubble, right? It doesn't actually have transmission constraints within the -- within the zone. So what we're trying to do here is just do this adjustment to reflect the fact that once we calculate the avoided cost using the PROMOD model without the intra-zonal congestion and losses, we need to take that into account to where they're actually locating, where they're actually injecting power. So that's the intent of the LMP adjustment.

The line loss is similar, where we are looking at -- for the standard offer we've got to look at, okay, what is the average line loss right now across the whole service territory? And it might be helpful if you refer to my direct testimony, the exhibit I provided. And I'm not going to take a lot of time, I promise, to go through this, but I do just want to kind of highlight why we're saying that across the system is zero, maybe even -- maybe even negative losses.

So I'm looking at my exhibit of my direct, and what this provides is from September 15 to September 16 --

Q Mr. Gaskill, can you remind -- did you say what page that is of your direct?

A I'm sorry. Yeah. So I'm in my direct exhibit, and it's -- I'm going to start at page 3. So it looks -- it's that page. So it's at the, yeah, end of my direct.

So what this is providing, and there's thirty -- I believe there's 33 transformers that we're presenting. So these are the transformers in which we've had QF generation thus far. So -- and it's showing the sub at every 30 minutes for that year, September 15 through September 16, what the load flow is on that transformer. So positive in this case means it's going in the right direction, caught the right direction, so it's coming from the transmission grid into the -- into the distribution grid. If it was negative, that indicates reverse flow, so from the distribution grid.

Okay. So if you looked at this transformer -- so Carolina Transformer Number 2, you would look at -- okay, I labeled this as positive, so meaning, okay, this is generally going in the right direction. There's still load to offset on that transformer. So if a new QF came and interconnected there and began generating, that QF could potentially be avoiding line losses in that case.

However, there's -- so you can see the average flow. I'm going to kind of eyeball it as, you know, between, say, 10 and 15 megawatts there. There's already 13 megawatts in the queue on that circuit. So once that's interconnected, there's -- you're basically going to be neutral. You're going to have some negative hours, some positive hours. So any new QF that we sign up after that is not going to be avoiding any additional line losses.

Flip over, I'll just go to Whitakers, and you can see these two -- I'm going to kind of look at page 4 and 5 together. These are two transformers at the same substation, so you still have one load coming into the substation; you just may have generation or load split between the two transformers. So you can see this one, Whitakers 1, has both positive and negative, but if you were to add any more QF generation there, I mean, you're already negative in the hours where the QF is generating. So if you broke this into day and nighttime, what you would see is the positive is nighttime hours where -- generally speaking, where you don't have QF generation, there's no solar generation so you have positive load flow in those hours. When the QF is actually generating, it's creating reverse flow. You look at Whitakers Number 2, which again is the same substation, that's all negative. There's actually no load on that circuit in most hours because the load is actually coming through Transformer Number 1, but you have QF generation.

So you kind of have to add those two together to get sort of the total QF generation and the total load. So, again, this is already negative. Add another QF genera--- it's going to be adding two losses because now you're adding to the reverse flow. So, I mean, I'm not going to go on and on, but you would flip through. And if you look at what's actually here, the situation where we're already -- you know, whether it's positive or negative, plus what is already in the queue, and in particular what's -- the IAs that are already signed and under construction. So we know what's coming on, and then we have a pretty good estimate of what will be coming on -- maybe they haven't began -- executed the IA, but they're in a queue, pretty much all of these would end up indicating predominantly reverse flow during the QF generation.

So that's why we say across the territory, any additional QF generation on these circuits are not going to be avoiding line losses on average. Most of them will actually be adding to because they'll be adding to the reverse flow. We haven't proposed a negative line loss in the standard contract. We just -- we settled on zero. But the idea would be if you then have a non-standard QF, you know exactly where they're going to locate, so we can actually go and say, okay, you're going to be connecting to Battleboro transmission or Transformer Number 3 or -- you know, we can actually look at the load on that circuit. Are you -- is there load to offset or is there -- are you going to be adding to the reverse flow, and then we can kind of customize the line loss percentage to that particular contract. So that's the idea here.

Q Okay. Thank you.

A That was a very long answer to a simple question, I think.

Q That's all right. I'm going to stay with LMPs for just a moment. I think Ms. Harrod with the AG's office asked you all about the data we included -- sorry

-- that Dominion included in Bruce's direct at Figure 3 about the gap between the DOM zone LMPs and the North Carolina LMPs. And you were discussing with her the reasons for that gap. Since there's been some overlap between you all on this topic, I'm actually going to ask, Mr. Gaskill, would you turn to your rebuttal, page 26? And at lines 8 through 15, did you testify there "That there are two factors that cause LMPs to be different from one location to another: congestion and marginal losses." Is that correct?

A That's what it says, yes.

Q Could you just read the rest of that paragraph, please?

A So "LMPs are fundamentally a function of supply and demand at each location - generally speaking, as supply increases, LMPs decrease. If demand increases, LMPs increase. As more generation is added in a location where it is not needed, the cost of congestion and marginal losses increases, reflecting the re-dispatch cost to enable this generation to flow to locations on the transmission grid where it is needed to serve load."

Q Thank you. And then, similarly, there was a question about the overpayment of the $381 million. You talked a little bit, Mr. Petrie, about the decline in gas and power prices. Would you agree with me that other reasons for this disparity stem from the 5 megawatt threshold and the 15-year term that is in place in North Carolina right now?

A (Petrie) Yes. I would agree with that. The -- there are definitely contributing factors. When you look at how we calculated the $381 million, it was -- again, it was the price difference between the rate that we pay under the contract versus our current projection of our avoided cost multiplied by the production from the QF facilities. The fact -- the production from those QF facilities is definitely impacted by the 5 megawatt threshold that we've had in the -- that we've had, and we believe changing that to the 1 megawatt threshold would help put things back in balance so we wouldn't be -- so we couldn't quite get into this overpayment situation in the future. It would try to help fix that. Same thing with the length -- the duration of the contracts going from 15 years to 10.

Q Thank you. Mr. Gaskill, do you recall Ms. Mitchell asking you about how a utility uses a forecast to build generation and might overpay for that generation?

A (Gaskill) I recall that.

Q And you responded that when Dominion builds its own generation, it makes the case that it can beat the market or, you know, is beating the avoided cost rate, correct?

A Yes.

Q It's building at least cost, right?

A Yes.

Q And it -- the Company has to go to this Commission or the Virginia Commission and through complicated proceedings to receive approval to build generation, correct?

A That's correct. We have to prove that it is the least cost resource, that it's, you know, necessary, and that we couldn't purchase the power for less cost.

Q And the customers still get the benefits from a facility going forward, even if -- a Company built facility, even if your initial forecast of cost is off, correct?

A They do. And I believe Mr. Snider talked a lot about this yesterday. I mean, I think the context in there was a coal unit. It still has value. It still has capacity value. It still has optional value. To the extent, say, your fuel forecast goes up, you only run that unit when it's actually in the money. So you have essentially, depending on the unit, almost a minute-by-minute or an hour-by-hour option whether to run that unit or not. So that still adds a tremendous amount of value. Contrast that with a take or pay contract where it's just coming whether you need it or not.

Q In fact, the Utility comes in every two years -- every year, actually, to this Commission to adjust the fuel portion of its rates, doesn't it, to reflect the increases and decreases in the market?

A Yes.

Q And that's not the case with a standard or a negotiated 10 or 15-year contract with QFs, correct?

A Right. You're locked into that price for the duration of the contract.

Q Could you just -- I'll wrap up by just asking you to explain why it is that location matters for a QF siting on your service area in North Carolina for purposes of avoided cost?

A Right. I mean, I think there's a -- there's a couple of pieces to that. I think we've hit on a couple of those. From the energy standpoint, you know, there's the LMP adjustment and what is the actual marginal system cost it's avoiding. There's the loss component, that are they actually avoiding losses when there's a saturation of QFs on this circuit. So I think those are the big ones from the energy standpoint.

From the capacity standpoint, and Mr. Petrie may want to add to this, I mean, I think what you've got to look at is -- fundamentally, is number one, there's no short-term need for capacity. When you look at a current IRP, you look at the trends of load growth continuing to push out those -- kind of that next CT year after year. So the question is, is there even a need short term. And then you've got to ask yourself is adding more intermittent generation where there's no more load to offset or minimal load to offset on the outside of our service territory, is that really going to avoid the need to build a dispatchable combustion turbine in the future for our system where there actually is load. And I think that's really the fundamental question that we're proposing here. I don't know if you would like to add anything to that.

A (Petrie) The only other thing I might add is as far as the capacity need goes. So when -- one of the other items that I touched on in my testimony is with -- with the amount of solar being added to the system, one of the things that we're looking at is installing some aeroderivatives combustion turbines on the system to help

-- to help offset some of this intermittency from this large amount of solar generation that's coming on. So, you know, it's -- so it's something that the Company is looking at seriously. We haven't bought any of these machines yet, but we're looking at it. And these machines, they're quick start and they're fast ramping, so they -- to help -- to help to keep the system stable and offset the intermittency from some of the renewable generation. The catch is it's more expensive. I quote a number it's 67 percent more expensive than a conventional large frame combustion turbine. So that's the other consideration here is in some respects, adding intermittent generation is, in some respects, not avoiding capacity costs. It's actually adding to capacity costs because we're -- we may have to spend more money because of these quick start, fast ramping aeroderivative machines.

Q Thank you. And I'm sorry, I do have one more. Could you speak, Mr. Gaskill, to why the proposals this Company is making will benefit customers and keep them indifferent as to PURPA purchases, first of all?

A (Gaskill) Sure. Yeah. I mean, as we've heard numerous times in the last couple days, I mean, the purpose of this is to encourage QF development while balancing the risk of overpayments to customers. So the proposals we're making, the shorter contract term that we've talked about allows a more frequent reset of the avoided cost rates so we're not locked into the long-term, you know, as long of a term. So that ensures that -- again, we still have an obligation to buy their power even if we -- of the contract, but it allows us to ensure that throughout that life, it doesn't get out of line with actual avoided cost. The smaller threshold, going from 5 megawatts to 1 megawatt as we talked about, you know, allows more customized rates. It allows the LEO timing to be -- and therefore the calculated avoided cost rates to be more in line with the actual operations of that QF and also kind of prevents, you know, the -- I'd say the gaming of the system where you can break up a large portfolio into 5.0 megawatts just to take advantage of the 2-year old rates. So I think that largely solves, not completely, but it's a step in the right direction to solving that staleness issue.

And then the other proposal is the LMP adjustment, the line loss adjustment, is again just more aligned with the QFs that are actually interconnecting here with our actual avoided cost.

MS. KELLS: Thank you.

CHAIRMAN FINLEY: Questions by the Commission? Commissioner Bailey?

EXAMINATION BY COMMISSIONER BAILEY:

Q Good morning.

A (Petrie) Good morning.

Q This is going to be questions for either one of you on the Panel that can answer the question, and maybe none of you can answer the question.

My first question, are you aware of a potential House Bill that's about to be introduced in the North Carolina General Assembly that's dealing with what they call a balanced energy solution in North Carolina that deals with QFs and some other items like that?

A (Gaskill) I'm generally aware. I have not been involved in the -- you know, in that stakeholder process, but...

Q Dominion North Carolina has less than 150,000 customers in North Carolina as of January 1st, 2017; is that correct?

A I believe that's the case, yes.

Q Are there any solar -- large solar, utility solar north of -- just north of the North Carolina Dominion Power territory in Virginia? Is Virginia building any large solar like you're seeing in your

Dominion North Carolina territory?

A Not to the level that we're seeing here. There -- I mean, so Dominion, we just had three projects come online at the end of 2016 that was 56 megawatts. There's -- I know we have a PPA that came as a result of an RFP that should be coming online later this year.

CHAIRMAN FINLEY: Where?

THE WITNESS: Where? In Virginia. Essex County, Virginia.

A (Gaskill) There are other merchant generators, merchant solar projects that are coming -- either are online or under development in Virginia that are selling into PJM.

Q Okay. What is Virginia's standard contract dealing with PURPA in the state?

A It's very similar to our Schedule 19 LMP.

Q Can you explain what that is?

A Yeah. It's an LMP based, so it's not a -- you know, it's not a 10-year or 15-year fixed price. It's basically we buy the power, and whatever the locational marginal price is at that -- or actually it's at the DOM zone, we sort of -- they're generating 10 megawatts and the price is -- in that hour is $50, then we would, you know, multiply, and that's what we pay them.

Q Do they have a standard size contract, like 5 megawatts or 1 megawatt in the state of Virginia that you just have a standard contract that applies?

A It's 20 megawatts and below, but they're all just LMP based.

Q LMP based. Okay. Thank you. Are you familiar with the Amazon wind farm that just came online in North Carolina selling into PJM? It's a 208 megawatt wind farm.

A Oh, the wind farm, yes, sir.

Q Okay. And are you aware that there's some other wind farms in an area that is in the process of permitting at this point in time?

A I'm not -- I'll take your word for it.

Q Well, this whole question deals around with transmission. Are you aware of any transmission lines that PJM is planning in the North Carolina area to try to take some of this solar that we've got back into their territory?

A I'm not the transmission planning side. I recall seeing a data response in this case that there was maybe one line planned for several years out, but I'm not -- I don't know the details.

Q Would you be in agreement that even though

North Car--- Dominion North Carolina Power has similar issues as Duke Energy or Duke Energy Progress does in the eastern part of the state, you have similar issues, but the longer term issue is not necessarily the same because you guys, Dominion North Carolina Power, is in PJM?

A That's right. And so I don't think we're seeing kind of the real-time operational yet -- the operational impacts, kind of the overgeneration events, that Duke has described.

Q So more specific, in the future you don't really see a situation where you're going to have so much excess power generation that you're going to have to sell it or give it away to some other balancing authority?

A Well, where -- if that occurred, how that would manifest itself in PJM is you would see actually negative LMPs.

Q Okay.

A That has occurred not a lot yet. There are a few hours where you see negative LMP. That's an indication of extreme congestion on the system where you have an overgeneration event and no lines to take it out. You see that happening a lot, say, like in the Midwest, you might say, where you have a lot of wind --

Q Right. A lot of wind.

A -- you have negative LMPs. We haven't really seen that.

Q That's a good point. You don't really see that taking place in Dominion, PJM area of the state?

A Not in the immediate future. Again, it depends on how -- I mean, you have a lot of -- if you get enough solar or wind, it could very well happen.

COMMISSIONER BAILEY: Okay. Well, thank you.

CHAIRMAN FINLEY: Follow-up question.

EXAMINATION BY CHAIRMAN FINLEY:

Q Gentlemen, I'm looking at this NCSEA DNCP Cross Examination Exhibit Number 1. It lists, my assumption is, all the projects with the various activities in North Carolina. All those -- a lot of these on the first and second page have been canceled. My understanding is about 5 percent of your business is North Carolina and 95 percent of it is Virginia?

A (Gaskill) Yes, sir.

Q If you had a similar exhibit as to this for your Virginia service area, how would it compare in terms of the level of activity with respect to qualified facilities?

A In terms of qualified facilities it would be minimal.

Q And why is that?

A I would venture -- I believe it's the implementation -- the differences in the implementation of PURPA from state to state. Again, when you -- as we've discussed for the last couple of days here, when you have an implementation that gives 15-year fixed prices, particularly at avoided cost that are well above market, that's going to encourage a lot of QF development.

CHAIRMAN FINLEY: Thanks. Commissioner Brown-Bland?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. Gaskill, I just wanted to understand or make sure I understand what you were saying about the -- if Dominion had to come to the Commission to build its own generation, that it has to do so cheaper than what you could get in the market. So you mean -- does that mean that -- so what you're saying is that you cannot find the capacity that you need in the market at a price that's less than what you could just go to the market and do a Power Purchase Agreement; is that right?

A (Gaskill) Yeah. Generally speaking, that's accurate. I mean, so what we would do through the IRP process, we would say, okay, there's a forecasted need for new -- it's energy and capacity -- I wouldn't say it's just capacity, but it's -- you know, we've got to meet both. So there's a need, future need. So you look at what's the best resource to meet that need, whether it's combined cycle, CT, so and so forth. Oftentimes that merits, you know, requests for proposal. Is there someone else that can meet that need -- meet that need cheaper? We've done that in the past. So you go out for -- and you look at market alternatives to figure out is there another generating resource or a market alternative that can meet that need cheaper.

Q Right. So there's -- it's just -- yeah. It's just that there's no alternative in the market at a market price, at an avoided cost rate price, regulated price, non-regulated price. It's just not -- that's what you have to establish, that you can't get it at a lesser cost --

A Yeah. I mean, there's always --

Q -- so you're willing to build at the --

A Yeah. I mean, I would always say that there's somebody willing to build if there's a right price. So capacity and energy is probably available at whatever price, you know. So what we're trying to get at is what is the least cost way to do that.

So what -- and I'll give an example. When our -- so we're constructing our Greensville combined cycle right now, so that CPCN proceeding was in Virginia, I want to say, a couple years ago. So we would go in and -- so we did an RFP for that. So we, first of all, identified a need for the future, so you look at what's the best, looking at energy capacity, current market prices, forecasted market prices. We do a number of sensitivities, high/low, so on and so forth. So you say what is the best technology, selected a combined cycle. So then you go out for an RFP and you say, okay, can anybody provide a combined cycle or that particular RFP was for any baseload type resource, so it wasn't just restricted to combined cycle. But then you say can somebody provide -- fill this need for cheaper than what we can build it, and we demonstrated that that combined cycle had significant savings below both our forecasted market price as well as other -- build alternatives, PPA alternatives.

COMMISSIONER BROWN-BLAND: All right. Thank you.

CHAIRMAN FINLEY: Further questions from the Commissioners?

(No response.)

CHAIRMAN FINLEY: Questions on the Commission's questions from the intervenors?

EXAMINATION BY MS. MITCHELL:

Q Mr. Gaskill, following up on the question -- one of the questions asked by Commissioner Bailey regarding solar -- plans for solar development in Virginia's service territory, do you recall that in its initial comments Dominion recognized a need for additional solar generation on its system and indicates that it's committed to building or purchasing 500 megawatts by 2020 in its Virginia and North Carolina service territory?

A (Gaskill) That's correct, yeah.

MS. MITCHELL: Okay. Thanks.

MS. KELLS: I just had one.

EXAMINATION BY MS. KELLS:

Q This is also following up on Commissioner Bailey's question. Those solar facilities in Virginia, are those PURPA QFs?

A (Gaskill) They are not.

MS. KELLS: That's all.

CHAIRMAN FINLEY: All right. We've got six exhibits: Gaskill Direct Exhibit Number 1, Rebuttal Exhibit Number 1, Petrie Direct Exhibit Numbers 1 and 2, NCSEA DNCP Cross Examination Exhibit Number 1 and Public Staff Gaskill Cross Examination Exhibit Number 1. Are there objections to the introduction of any of those exhibits? If not, they are introduced into evidence.

(Whereupon, Exhibit JSG-1, Rebuttal Exhibit JSG-1, Exhibit BEP-1, Confidential Exhibit BEP-1, Exhibit BEP-2, NCSEA DNCP Cross Examination Exhibit 1, and Public Staff Gaskill Cross Examination Exhibit 1 were admitted into evidence. Because of the proprietary nature of Confidential Exhibit BEP-1, it was filed under seal.)

CHAIRMAN FINLEY: And this Panel may be excused, and we'll take a recess until -- yes?

MS. KELLS: Can I also move that the Company's Initial Statement and 12 exhibits be admitted into evidence, please?

CHAIRMAN FINLEY: Without objection, that request is granted.

MS. KELLS: Thank you.

(Whereupon, Initial Comments and Exhibits of Dominion North Carolina

Power were admitted into evidence.)

CHAIRMAN FINLEY: We will take a recess until 25 until 12:00.

(Recess taken from 11:21 a.m. to 11:36 a.m.)

CHAIRMAN FINLEY: All right. Which Intervenor wants to call the next witness?

MR. CULLEY: Thank you, Mr. Chairman. By agreement of counsel, Cypress Creek would like to call its witness ahead of NCSEA's, as Mr. McConnell has requested a date certain, although very optimistic, we're moving along now. Cypress Creek would like to call Patrick McConnell.

CHAIRMAN FINLEY: All right.

PATRICK McCONNELL; Having first been duly sworn, Testified as follows:

DIRECT EXAMINATION BY MR. CULLEY:

Q All right. Well, good morning, Mr. McConnell.

A Good morning.

Q Could you please state your name and business address for the record.

A Patrick McConnell. My primary business address is 3250 Ocean Park Boulevard, Santa Monica, 90405.

Q And Mr. McConnell, by whom are you employed and in what capacity?

A Cypress Creek Renewables. I'm a Managing Director in charge of project finance.

Q Okay. Thank you. And on March 28, 2017, did you cause to be filed 8 pages of direct testimony on behalf of Cypress Creek Renewables?

A I did.

Q If I were to ask you the same questions today, would your answers be the same as given in your prefiled testimony?

A Yes, they would.

Q And Mr. McConnell, do you have any corrections to make at this time?

A No, I do not.

MR. CULLEY: Okay. Mr. Chairman, I would move to add Mr. McConnell's direct testimony marked for identification and copied into the record as if delivered orally from the stand.

CHAIRMAN FINLEY: Mr. McConnell's direct testimony filed March 28, 2017, consisting of 8 pages, is copied in the record as though given orally from the stand.

MR. CULLEY: Thank you, Mr. Chairman.

(Whereupon, the prefiled direct testimony of Patrick McConnell was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Biennial Determination of Avoided Cost
Rates for Electric Utility Purchases from
Qualifying Facilities – 2016

DIRECT TESTIMONY

OF

PATRICK MCCONNELL

ON BEHALF OF
CYPRESS CREEK RENEWABLES

OFFICIAL COPY

Q. Please state your name, occupation, and employer.

A. My name is Patrick McConnell. I am a Managing Director and part owner of Cypress Creek Renewables ("CCR"), a utility scale solar developer with a primary focus on the development, construction, and operation of qualifying facilities ("QFs") nationwide. My primary role at CCR is managing the project finance team.

Q. On whose behalf are you providing this testimony?

A. I am providing this testimony on behalf of Cypress Creek Renewables.

Q. What is the purpose of your testimony?

A. I have been asked to provide testimony regarding the impact of some of the changes proposed by Duke Energy Progress, Duke Energy Carolinas (collectively, "Duke"), and Virginia Electric Power Company (collectively, "the Utilities") in their avoided cost filings on Cypress Creek's project development, and more broadly on the development of QFs in North Carolina. Specifically, I discuss the following proposals made by the Utilities: (1) the proposal to eliminate the 5- and 15-year options for standard offer fixed contracts in favor of a single 10-year option; (2) the proposal to readjust energy prices under standard offer contracts every two years; and (3) the proposal to reduce the standard offer threshold to 1 MW.

Q. Have you testified before this Commission or any other utilities commission?

A. I have not previously testified before this Commission. I have testified before another utilities commission on one occasion. In late 2016 and early 2017, I testified before the Montana Public Service Commission, on behalf of Cypress

Creek Renewables and FLS Energy, in the currently-pending avoided cost proceeding for NorthWestern Energy (Docket No. D2016.5.30). My testimony addressed two issues on which the Montana Commission had requested additional testimony from the parties: standard-offer contract length and performance measures with respect to QF contracts.

Q. **Please describe your experience in project finance and more specifically solar finance.**

A. After graduating from the University of Virginia with a B.A. in Economics and a Concentration in Finance, I began my professional career in the Structured Finance Group of Legg Mason Capital Markets. As the lead analyst of the Structured Finance group, I focused on the modeling, underwriting, and financing of long-term credit tenant leases and corporate asset monetization programs. Our group, as part of Legg Mason and then later RBS Greenwich Capital, originated and structured over $2 billion worth of securities backed by long-term, investment grade leases, very similar to the credit profiles found in long-term utility power purchase agreements.

After obtaining my MBA at the University of North Carolina but prior to joining Cypress Creek, I spent four years within the structured finance team of Stonehenge Capital Company, a boutique investment bank focused on tax incentivized investments for institutional and corporate clients. These investments ranged from film productions, brownfield remediations, historic rehabilitations, low-income housing developments, and of the most relevance, renewable energy installations.

After participating in the financing of over $300 million of renewable project financings at Stonehenge, including landfill gas-to-energy, solar thermal, and solar PV projects, I co-founded Heelstone Energy, LLC, a privately owned solar developer and independent power producer. Heelstone now operates a solar PV portfolio in excess of 200 MW.

Q. Please elaborate on your day-to-day role at Cypress Creek.

A. At CCR, my primary responsibilities include sourcing construction and permanent capital for all of our solar project portfolios, then leading the transaction executions with our capital partners. Outside of outright project sales and sale leaseback transactions, every financing transaction we close involves permanent debt and tax equity investors. Typical investors of both debt and tax equity include large banks, insurance companies, and public corporations.

Q. What are the sources of funding that Cypress Creek generally uses to finance the construction and operation of its solar projects in North Carolina?

A. Like most other solar developers, Cypress Creek uses a combination of sponsor equity (internal capital), construction loans, permanent loans, and tax equity to finance the construction and operation of all of its projects in North Carolina. "Tax equity" refers to equity investments where the investor's primary return can be attributed to its right and ability to utilize investment tax credits and other tax benefits generated by the project. The biggest players in the tax equity market are large banks, corporations, and other institutional investors. Each piece of the external capital stack (construction debt, permanent debt, and tax equity) is sourced from different partners on a deal by deal basis, but to date CCR has used over 25 different capital providers in those roles.

Q. In the capital raising process, can you speak to the importance of the credit quality and tenor of the PPA?

A. Those two pieces of information, along with the actual pricing of the power purchase agreement ("PPA"), are the most critical components of the entire financing. Similar to financings I was involved with in the real estate world, where investors were focused on the credit quality of the tenants above all other things (as opposed to the underlying value of the real estate), investors in renewable energy are primarily focused on the strength of the off-taker and the details of the off-take contract signed. Technological risk has become less of a concern as the industry has matured, but the utility's balance sheet (or FICO scores in the residential world) is of the utmost importance.

Similarly, the term of the contract is equally significant. Without reasonable certainty as to contracted cash flows based on a defined term at a defined price, the institutional marketplace is generally unwilling to take pricing risk. Said a different way, project lenders are unwilling to bet on a utility's avoided cost in QF markets, unless set forth in a fixed contract. In the absence of some sort of third-party credit enhancement (like a government guaranty), I've yet to see a loan maturity or amortization for a project under 75 MW extend beyond the term of a fixed-price PPA. This means that substantially more sponsor equity would be required to generate sufficient funding for the construction and operation of the project. As a result, the cash flow profiles of investments with PPAs of less than at least 15 years, and in most cases 20 years, simply do not make economic sense for smaller projects.

Q. **How would the utilities' proposal to limit the length of standard-offer contracts to 10 years impact the development of QFs in North Carolina?**

A. As mentioned in the previous answer, for smaller projects (and even for the majority of larger projects), lenders are generally unwilling to lend against uncontracted cash flows. This is especially true for smaller transactions projects (below about 50 MW), that are not of sufficient scale to attract larger, more sophisticated investors who may be willing to accept a few years of merchant or avoided cost exposure if certain underwriting protections are in place. Many in the industry actually consider the original standard offer contract length of 15 years to be insufficiently long compared to average utility contract tenors of 20 or 25 years. 10-year PPA tenors will lead to 10-year amortization periods, which will mean less debt and greater sponsor equity requirements at lower returns and greater risk. This in turn will result in many fewer projects getting financed and constructed.

Q. **How would the proposal to limit standard-offer contracts to 10 years impact equity financing for QF projects?**

A. Limiting contracts to 10 years would have a two-fold impact. First, by reducing the amount of debt available to finance the project, it would increase the amount of equity required and thereby reduce the rate of return on that equity investment. Second, due to a larger percentage of the project's cash flows being uncontracted and inherently riskier, the projected rate of return required to attract equity investments would be significantly higher. These two dynamics in conjunction would make it significantly more difficult if not impossible to attract the required level of equity investment.

Q. Can you also speak to the importance of having fixed energy prices under a long-term PPA?

A. I view energy prices as one in the same with contract tenor for QFs subject to PURPA in regulated markets. Technically speaking, any QF is entitled to the avoided cost rate at any time per PURPA. What creates value in the contract is having a set avoided cost rate for a set period of time. Without set rates, lenders are unwilling to bet on what the avoided cost rates will be going forward. Fixed rates for a fixed period of time create financeable contracts.

Q. How would Duke's proposal to readjust energy prices under standard offer contracts every two years impact the development of QFs in North Carolina?

A. As I mentioned earlier, QF status entitles a project to sell to the utility at an avoided cost rate even without a PPA, so in a regulated market a ten-year contract with a two-year reset for energy prices would be viewed as more or less equivalent to a two-year contract. Having fixed capacity pricing for the duration of the contract would not make a significant difference, especially given the relatively low price of capacity under the proposed rate schedules. Financing parties would view a ten-year contract with a two year readjustment no more favorably than they would a two-year contract, which (as I have said previously) would not be financeable in the current environment.

Q. **How would the Utilities' proposal to reduce the standard-offer threshold to 1 MW impact the development of QFs in North Carolina?**

A. Given the complicated nature of these financings, scale is critical in project financing. Reducing the standard offer contract threshold to 1 MW would make financing projects in North Carolina much more challenging. The only way to make most financings work with a 5 MW threshold was to group them into portfolios to create critical mass for debt and tax equity investors. With a 1 MW limitation, the portfolio size would quickly become unwieldy due to the amount of diligence required for that number of projects. It would largely shut out the institutional market from financing standard offer contracts.

Q. **Given CCR's focus on QF Markets, can you explain why investors cannot simply rely on the regulatory framework in place in these markets to ensure projects will have viable offtake agreements beyond the PPA terms?**

A. While QF markets are certainly a key piece of the CCR strategy of investing in long-lived assets that will have considerable value long after the initial PPA has expired, institutional lenders are generally unwilling to take pricing risk beyond the PPA term. So while the QF designation affords CCR greater economies of scale for our development efforts and improves the long-term viability of each project we develop, it does not typically provide for enhanced upfront financing.

Q. **Does this conclude your testimony?**

A. Yes.

Q And Mr. McConnell, have you prepared a written summary of your direct testimony?

A I have.

Q And could you please provide that at this time?

A I may. Good morning, Mr. Chairman and Commission. The purpose of my direct testimony is to discuss the impact that some of the proposals the Utilities have made in this docket would have on QF development in North Carolina, and specifically on the ability of standard offer QFs to attract capital for financing.

I focus on three of the proposed changes: The proposal to eliminate the 5 and 15-year options for standard offer fixed contracts in favor of a single 10-year option; the proposal to readjust energy prices under standard offer contracts every two years; and the proposal to reduce the standard offer threshold to 1 megawatt.

Individually and in combination, these proposed changes would make it much more difficult to finance and construct smaller solar QF projects in North Carolina. Most solar developers use a combination of its own sponsor equity, construction loans, permanent loans, and tax equity to finance the construction and operation of its North Carolina projects. Having reasonable certainty as to the long-term cash flows is crucial to obtaining capital from these sources. As a result, price certainty and PPA duration are the two most important factors that determine a project's ability to obtain financing. Without the cash flow certainty provided by a long-term contract with fixed prices, lenders are unwilling to take the bet on what a solar project's long-term returns will be. Consequently, a project generally must amortize all of its debt over the period of time during which it has fixed contract rates, and shorter amortization periods result in less debt financing being available. The less debt financing that is available for a project, the more sponsor equity is required to build it. The larger the equity contribution, the lower the rate of return on equity. At a lower rate of return, equity investors, including our Company, will tolerate less risk and will be less likely to invest in projects.

Here is what this means in the context of the changes the Utilities propose to standard offer contracting in North Carolina. The reduction in maximum contract term to 10 years means that small QF projects will now have to amortize their entire debt over a 10-year period, which means less available debt and greater sponsor equity requirements so that project equity earned a lower rate of return at a higher risk. What's more, a term of only 10 years means that the larger percentage of the project's cash flow over its operational life will be uncertain and inherently riskier, so the projected rate of return required to attract equity investments will be significantly higher. In my experience, small QFs would likely have difficulty obtaining sufficient debt and equity to finance construction and operation with a PPA of only 10 years.

Duke's proposal to readjust energy prices every two years under standard offer contracts would pose an even bigger obstacle to obtaining financing for QFs. From the standpoint of financing parties, a 10-year PURPA PPA, where rates are subject to change every two years, is nearly indistinguishable from a 2-year fixed rate contract. And the same factors that make 10-year fixed rate PPAs difficult to finance would make a 2-year fixed rate contract nearly impossible to finance under current market conditions. And because capacity rates make up a relatively small proportion of a standard QF's long-term revenue, Duke's proposal to fix capacity rates would not make a significant difference.

The Utilities' proposal to reduce the standard offer threshold from 5 megawatts to 1 would only compound the problems I've already discussed. In general, the smaller the project, the more difficult it is to obtain financing, especially from institutional investors. So in combination with the problems that would be caused by the Utilities' other proposals, a 1 megawatt limitation on standard offer eligibility would make it difficult for many standard offer projects in North Carolina to obtain financing. Thank you.

MR. CULLEY: Mr. Chairman, Mr. McConnell is available for cross examination.

CHAIRMAN FINLEY: Any Intervenors here on the west side of the -- east side of the room have any questions?

CROSS EXAMINATION BY MS. FENNELL:

Q Hi, Mr. McConnell. Heather Fennell with the Public Staff. So it is our understanding that Cypress Creek's initial model for project development in North Carolina is generally built around 5 megawatt projects. Is that your understanding?

A Generally correct.

Q How many operational projects does Cypress Creek currently have in North Carolina, to your knowledge?

A I think the number, including the transaction where we purchase FLS' assets at the end of last year, is up to around 105.

Q Okay. And of those, approximately how many are at or below the 5 megawatt threshold?

A Based on some numbers I looked at a couple days ago, about 85 percent of those are in the 5 megawatt range.

Q Over the past year it appears that you all are moving away from that and going to larger negotiated projects; is that true?

A Generally correct.

Q And could you explain why that transition is happening?

A The primary impetus, it's not my core competency to direct development efforts of the firm, but as I understand it, that change in strategy for Cypress Creek was primarily dictated by conversations that principals in our firm, mainly Mike Cohen and Steve Levitas, had with Duke, I think it was Gary Freeman at the time, directing us to large transmission projects being more attractive to Duke who we view as our largest, most important customer. So we were trying to be receptive to their demands.

Q Okay. Are you aware of how successful your negotiations have been in developing these larger projects with Duke?

A In terms of the success, it's hard for me to opine there. Again, that's not what I do on a day-to-day basis is negotiate PPAs. However, my understanding of the process has been while we've gotten PPAs out of the process, it hasn't been much of a negotiation. Duke has indicated its pricing, and it's a fairly take it or leave it proposition, but we have been able to obtain PPAs for the larger projects.

Q On page 8 of your testimony you state that the only way to make most financing work with a 5 megawatt threshold was to group them into portfolios to create a critical mass for debt and tax equity investors. Can you please describe how the portfolios or projects were assembled for marketing development?

A I can. So typically we are working with groups of tax equity investors and debt providers, and it's very difficult for them to make the economics of their investment work investing in a one-off project. They typically want to deploy more capital, given the fixed costs required and the level of diligence and transactional work that's required to get one of these deals done. And so typically we are marketing the projects and portfolios dependent on investor sizing thresholds that they have given us. So we'll take portfolios of two to 10 projects and try to match that with what investors say they are willing to invest in each project, and we market those in such a way that we try to structure our development efforts to be uniform in that all of the service providers are the same, the contracts looks the same, obviously the PPAs and Interconnection Agreements are the same, and so we try to make that expanded diligence process with a number of projects easier by that uniformity.

CHAIRMAN FINLEY: Ms. Fennell, if you will pull the mic up a little bit, please.

MS. FENNELL: Oh, excuse me. Thank you.

Q And part of this way of creating critical mass for debt and equity, is this also part of the reason why you've been creating larger projects?

A Yeah. Again, I think the primary motivation was a directive from Duke. However, there is economies of scale for doing larger projects. The build costs get marginally lower the bigger project you get, as well as the financing fixed costs get amortized over a larger project. And so it does make it marginally more creative for the larger projects. The larger portfolios you can do, the better.

Q And to your knowledge, have the delays in the interconnection process caused a change in how you're obtaining financing or the timing you're financing for your projects?

A Certainly. The three, you know, kind of pillars that I referenced earlier, the PPA, Interconnection Agreement and site control, whether that be a site lease or a title to the property via a purchase, are the three kind of foundational documents which we finance all of our projects, and without those, you can make very little headway with investors because they don't view the project to be credible.

With the smaller projects and standard offer projects, in certain cases we've gotten investors to get comfortable with the fact that if we have a signed Interconnection Agreement, they know that a PPA is forthcoming and they'll sign documents, but they won't fund anything until we have a fully executed suite of a site lease, an Interconnection Agreement, and a Power Purchase Agreement.

MS. FENNELL: That's all. Thank you very much.

CHAIRMAN FINLEY: Dominion? Duke?

MS. FENTRESS: Yes. Thank you.

CROSS EXAMINATON BY MS. FENTRESS:

Q Good morning, Mr. McConnell. My name is Kendrick Fentress. I'm an attorney with Duke Energy. How are you today?

A Good morning. How are you?

Q Thank you. Good. Thank you. Mr. McConnell, Cypress Creek Renewables is in the business of developing, constructing, and operating QFs; is that correct?

A Generally, yes, utility scale solar across a number of different verticals in the space.

Q Thank you. And its principal place of business is in Santa Monica, California?

A Yeah. We have a number of offices, including a couple large ones in North Carolina, but our headquarters is Santa Monica.

Q And is it true that as of January 7, 2017, Cypress Creek Renewables had over 750 megawatts of installed utility scale solar in North Carolina?

A I don't know that specific number, but that ballpark level sounds about right.

Q Would you agree that Cypress Creek Renewables has a complaint pending against Duke Energy at this Commission at the present time?

A To my knowledge, that's correct.

Q And would you agree that 750 megawatts would be the number represented in that complaint if you were to go and check?

A I can take your word for it.

Q Thank you. And is it also correct that Cypress Creek Renewables has over 2,000 megawatts in development in North Carolina of solar?

A Again, I don't know that number offhand. That does not seem beyond the bounds of reason to me.

Q Thank you. And would you agree that Cypress Creek's projects in North Carolina represent over 80 percent of Cypress Creek's total projects nationwide?

A Again, I don't know that offhand. Again, that does not seem unreasonable. I don't necessarily think that is consistent with our pipeline going forward, but certainly in operation that sounds roughly right.

Q So would you say the vast majority of your projects are -- projects and development are in North Carolina at this time?

A No, not in development. In operation, yes.

Q Operation.

A In development, I would not agree with that.

Q And can you identify what other states in the Southeast you have projects in operation?

A I think that's probably a bit confidential, but happy to disclose South Carolina, Georgia. We've got development opportunities in a number of other states, but the only states that we currently have operating facilities, unless I'm not remembering correctly, are North Carolina, South Carolina, and Georgia.

Q And are the operating facilities in Georgia under the PURPA construct?

MR. CULLEY: I'd like to object here. I think what's relevant here is what Mr. McConnell has to say about the QF market in North Carolina. And, you know, the only relevant issue that he's testified to is whether a 10-year PPA or a 10-year PPA with a 2-year reset would be financeable. So I think explore --

CHAIRMAN FINLEY: He's talking a lot of generalities about financial ability of the projects, so overruled.

Q Well, with that, let's get specific to North Carolina then. Specific to projects in North Carolina developed under the 5 megawatt standard offer, would you agree that Cypress Creek has approximately 100 5 megawatt projects that are currently in operation in North Carolina?

A I don't think that's right. I looked at the numbers a couple days ago. I think that based on the numbers that I reviewed it was 105, and I think roughly 85 of those were in the 5 megawatt range. It was roughly 85 percent was the numbers I reviewed.

Q Mr. McConnell, after you filed testimony in this docket, the Companies served upon Cypress Creek data requests. Are you familiar with those data requests?

A Yes, ma'am.

Q And Mr. Breitschwerdt is going to --

MR. CULLEY: I'm sorry, counsel. Which data request were you looking at?

MS. FENTRESS: I'm sorry. I'm looking at DEC and DEP Data Request 7. And can we have this marked as Duke -- I'm sorry.

CHAIRMAN FINLEY: Hold on just a minute.

MS. FENTRESS: Certainly. Mr. Chairman, if we could have this marked DEC/DEP McConnell Cross Exhibit Number 1.

CHAIRMAN FINLEY: It shall be so marked.

(Whereupon, DEC/DEP McConnell Cross Exhibit Number 1 was marked for identification.)

Q And I believe that Cypress Creek objected to this question, however, it did indicate in the subset (b) that Cypress Creek has a total of 99 North Carolina standard offer QFs that are under development; is that correct?

A Reading that correct, yes.

Q It also indicates that it has 102 standard offer QFs that have been placed into service since January 1, 2015?

A That's correct. To clarify my earlier comment, I believe the question was at a 5 megawatt threshold, and I think we have -- or I know we have a number of projects between one and three and a half megawatts that are not included in that number, in the previous 85 percent or 85 that I referenced.

Q Thank you for clarifying that. And so would you agree with respect to the majority of the projects in Cypress Creek's development pipeline, that they have locked -- in North Carolina, that they have locked into avoided cost rates that were approved by this Commission either in what I'll refer to as Docket Number E-100, Sub 136, which was the 2012 avoided cost proceeding, or Docket Number E-100, Sub 140, which was the 2014 cost proceeding?

A I really can't speak to the mix between which docket and which projects filed for. I would say there's certainly a number of them that were eligible for each docket number, but I really can't speak to the majority.

Q Well, if you have 100 or so 5 megawatt projects that are currently in operation in North Carolina and you have 100 5 megawatt projects or so that are in development in North Carolina, would you agree that total is up to about 1,000 megawatts?

A I would not actually say that because, again, that number does encompass a number of 2 to 3 megawatt projects, and I don't know what the number is. About 1,000 megawatts, sure --

Q Of 5 megawatts and under. I'm sorry. I was not asking specifically for 5 megawatts. I apologize. I was asking for 5 megawatts and under projects that are entitled to the PURPA standard offer in North Carolina.

A Sure, but I think you suggested that the 200 projects at 5 megawatts would be the gigawatt or 1,000 megawatts you referenced, and I don't think that is correct because I think it's actually lower because we have a number of 2 and 3 megawatt facilities that did not hit that 5 megawatt threshold.

Q I completely agree with you, but for those projects that are 5 megawatts and under, don't -- you do have about 100; is that correct?

A Yes.

Q And for those projects 5 megawatts and under that are in development, you would say you have about 100; is that correct?

A I think that's correct.

Q Okay. Thank you. And of those approximately 1,000 megawatts, I believe you indicated that, yes, they were eligible for avoided cost rates that were approved in prior avoided cost proceedings; is that correct?

A I know that we have projects that run the gamut from one that we had submitted our CPCNs probably, you know, as of well after November of last year, and ones before, and then ones probably before 2014. So I don't think there's any probably outstanding before 2012, but, yes, there's a mix across.

Q Thank you. And so you would agree that those 1,000 megawatts are locked into stale avoided cost rates and probably in long-term contracts for the next maximum of 15 years. Would you agree with that?

MR. CULLEY: Object with that question. We don't know what stale would mean in this context, and he has no basis of stating whether or not he agrees with what that is.

MS. FENTRESS: I'll elaborate. Stale means approved about five years ago, and stale means approved about two years ago.

CHAIRMAN FINLEY: Well, why don't you leave the stale out and just ask him about the contract?

MS. FENTRESS: Okay.

THE WITNESS: I didn't catch that, Chairman.

MS. FENTRESS: He asked --

MR. CULLEY: Would you repeat the question?

MS. FENTRESS: Sure.

Q You have long-term -- I mean, I'm sorry. You have 1,000 megawatts locked into avoided cost rates that were approved as long ago as 2012, I believe I think you said?

A That's correct. I do not know that -- I think the number in 2012 is de minimis if very few. I think 2014, certainly a large number in the latest docket at '16, correct.

Q Mr. McConnell, DEC Witness Snider testified -- have you read Mr. Snider's testimony --

A I have.

Q -- about the long-term significant financial obligations imposed on our customers? Do you recall that testimony?

A Not the specific portion, but I'm happy to review it if that's what you'd like me to do.

Q Well, in general, how about --

A Okay. Sure.

Q And he also testified about an overpayment risk associated with long-term fixed PURPA contracts. Are you familiar with that testimony?

A Sure.

Q Would you agree, then, that the 1,000 megawatts of QF solar that is eligible for avoided cost rates approved in prior avoided cost documents -- dockets, I apologize -- is imposing a significant long-term financial obligation on Duke's customers?

A I believe that it's certainly a long-term obligation and a long-term hedge as well at the time that that obligation was enforced.

Q And as we discussed earlier, after Cypress Creek filed its testimony, the Companies served data requests on Cypress Creek. Do you recall that?

A Sure.

MS. FENTRESS: And I'm going to ask Mr. Breitschwerdt to pass out an exhibit I'd like marked for identification. Oh, I'm sorry. It's Data Request DEC/DEP CCR Question 2. Mr. Chairman, may I have this marked DEC/DEP McConnell Cross Exhibit Number 2?

CHAIRMAN FINLEY: It is so marked.

MS. FENTRESS: Thank you.

(Whereupon, DEC/DEP McConnell Cross Exhibit Number 2 was marked for identification.)

Q Mr. McConnell, have you had a chance to take a look at that?

A Sure.

Q And will you agree with me that in this data request the Companies asked Cypress Creek if they would authorize the Public Staff and the North Carolina Utilities Commission to audit their books and records in making a determination whether Cypress Creek's QF projects have a reasonable opportunity to attract capital from potential investors?

A Do I agree that was the question?

Q Yes.

A Yes.

Q And is it true that Cypress Creek objected to answering this question?

A That is true.

Q And is it true that notwithstanding the objection, Cypress Creek did indicate it would consider a request by the Commission or by the Public Staff to provide financial information on a voluntary basis?

A That's correct. As a general practice, we don't -- a private company won't disclose their financial information publicly, but upon request be happy to do so.

MS. FENTRESS: I'd like to pass out another Data Request, DEC/DEP Cypress Creek Question 5. I apologize. Mr. Chairman, I'd like to have this marked DEC/DEP McConnell Cross Exhibit Number 3.

CHAIRMAN FINLEY: It shall be so marked.

MS. FENTRESS: Thank you.

(Whereupon, DEC/DEP McConnell Cross Exhibit Number 3 was marked for identification.)

Q Mr. McConnell, have you had a chance to take a look at that?

A Yes, I have.

Q And would you agree with me that this data request references your direct testimony that says, "To date, Cypress Creek has used over 25 different capital providers to provide debt and equity capital for the development of its solar PV projects"?

A Yes, ma'am.

Q And in the data request, the Company has asked you to identify those capital providers by name?

A Yes, ma'am.

Q And identify whether they had provided debt capital, equity capital, or another type of capital or financial support?

A Yes, ma'am.

Q And the Companies also asked you for a reasonable estimate of the gross total capital provided by each of the identified capital providers to Cypress Creek; is that correct?

A Yes, ma'am.

Q And is it also correct that Cypress Creek also objected to this question, indicating that it was prohibited from disclosing this information?

A Yes, ma'am. The -- our financial partners are what we view our most valuable -- or one of our most valuable assets, and we view those relationships as proprietary, and releasing that information of those investors would be disclosing trade secrets to our competitors publicly. And, further, I think that these were capital providers -- I think the scope of my testimony, as I understood it, was to pontificate under what future avoided cost and tenor -- PPA tenors would look like under a new regime. We've never objected to the fact that previous dockets do provide a reasonable potential to attract capital.

Q And that is part of your job, is it not, to --

A Yes, ma'am.

Q -- to attract capital?

A Yes, ma'am.

Q Okay.

MS. FENTRESS: I'd like to pass out an exhibit at this time that we have discussed with counsel for Cypress Creek with respect to the confidentiality of some of the pages of that exhibit. Mr. Breitschwerdt, thank you.

MR. CULLEY: Mr. Chairman -- Mr. Chairman, Cypress Creek objects to the introduction of this document. You know, for one, this evidence -- Duke hasn't laid any foundation for it. We have no idea where it came from. Duke got this --

CHAIRMAN FINLEY: Hold on just a minute. I don't have a clue what you're talking about there. Let me see what you've got.

MR. CULLEY: Okay.

CHAIRMAN FINLEY: All right, Mr. Culley.

MR. CULLEY: Thank you, Mr. Chairman. So it appears Duke got this off the Internet and it was not off Cypress Creek's website. It came from a third-party website. And at this time, you know, it includes information that has been marked as confidential. Cypress Creek has started an investigation into how this was disclosed, as it is our understanding that parties that had access to this were under nondisclosure agreements. And we're in the process of getting this -- making sure this is taken off. So we object that there's no foundation introduced and that it should be treated as confidential and the parties should have to clear the room if we go any further with it.

CHAIRMAN FINLEY: Do you mean Duke got it off the Internet? You know, to the extent that it was confidential and it's out there for everybody to see, somebody else breached their confidentiality, but it's public knowledge now, right? Am I missing something here?

MR. CULLEY: Well, a party has breached their confidentiality agreement apparently. And as I say, Cypress Creek is investigating this, but this document includes commercially sensitive materials. And Duke has discussed with Cypress Creek that they would treat this as confidential.

CHAIRMAN FINLEY: Do you object to its being discussed in this case in a confidential fashion?

MR. CULLEY: Yes. I object to the inclusion as there's no foundation for introducing this document.

CHAIRMAN FINLEY: Well, it's only been marked, so let's see what they can do about attempting to lay a foundation for it. But will the effort to make the foundation require use of confidential testimony?

MS. FENTRESS: No, I don't believe so. This is publicly available information, and I don't believe that the slides that I need to refer to -- well, they may be marked confidential, but, again, this is publicly available. We pulled it off the Internet after a Google search.

CHAIRMAN FINLEY: Well, I'm having trouble, Mr. Culley, understanding how something can be confidential when it has been on the Internet and that's how Duke got ahold of it.

MR. CULLEY: No, Mr. Chairman, I understand. And it's a regrettable situation that's occurred, but Cypress Creek has taken all due effort to minimize its further disclosure at this point. And I think it would be damaging and, you know, not necessarily probative to explore this right now. Treating it as confidential as Duke had recommended I think would be Cypress Creek's preference if we need to go forward to establish foundation -- for them to try to establish foundation.

CHAIRMAN FINLEY: Is that satisfactory to Duke, treat it as confidential in order to establish a foundation and potentially have the testimony on this exhibit received into evidence?

MS. FENTRESS: Yes. That is satisfactory.

CHAIRMAN FINLEY: Okay. All right. We will do that. And for the moment, we will ask those who have not signed a confidentiality agreement with respect to this exhibit, we'll ask them to -- is that what you're asking about -- is that what you're requesting -- to leave the room and we'll look at this exhibit. Madame Clerk, if you will mark this testimony after this point as confidential.

(COURT REPORTER'S NOTE: An Order Rescinding Confidential Treatment of Exhibit, filed May 1, 2017, ordered that DEC/DEP McConnell Cross Examination Exhibit Number 4 and the cross examination of Patrick McConnell thereon be a portion of the public record.)

CHAIRMAN FINLEY: All right. Duke?

MS. FENTRESS: Yes. Mr. Chairman, I'd like to mark this exhibit DEC/DEP McConnell Cross Examination Exhibit Number 4.

CHAIRMAN FINLEY: It shall be so marked, and for the moment we will mark it confidential.

(Whereupon, DEC/DEP McConnell Cross Examination Exhibit Number 4 was marked for identification.)

Q Mr. McConnell, have you had a chance to take a look at the exhibit?

A Briefly. I was not familiar with it before.

Q You will agree, I believe, that this exhibit -- you've heard it was on the Internet; is that correct?

A Yes.

Q And it was subject to a -- some agreement with a third party; is that correct?

A Certainly. Whenever we give a presentation of this nature, we always ensure that a nondisclosure agreement is signed. And no one, I guess, at Cypress Creek had been doing Google searches routinely to ensure that something like this wasn't online, and apparently someone went and did it on a rogue fashion.

Q And so you agree this is a Cypress Creek document subject to that type of agreement?

A I agree that it certainly looks and smells like a Cypress Creek document. I have no idea if it was altered in any way, shape, or form prior to being published.

Q You agree that the pages are represented as screenshots from an Internet website. Do you agree with that?

A They appear to be, yes, ma'am.

Q And you agree that that Internet website is the Coleman Report?

A Yes, ma'am.

Q Are you familiar with the Coleman Report?

A No.

Q You agree that on page 2 that the speaker who gave this presentation was David Thigpen?

A Yes, ma'am.

Q And is he an employee of Cypress Creek?

A He is, in fact.

Q And you work with him?

A Yes, ma'am.

Q And he's the Director of Project Finance at Cypress Creek Renewables?

A He is a Director of Project Finance, yes.

Q And he joined in late 2015; is that correct?

A Sounds right.

Q And so this presentation was likely made sometime between late 2015 and now; is that correct?

A Obviously, if --

MR. CULLEY: Objection. He says he has no basis for knowing what this presentation is or exactly when it was given.

MS. FENTRESS: Well, I believe it would be safe to say under bullet point 2 on Slide 2 that it was after 2015.

Q Do you see that date there, Mr. McConnell?

A I do.

Q Does Mr. Thigpen report to you?

A He does.

Q And you've never seen this before?

A I've not.

Q You're not aware of your direct reports' activities with respect to giving presentations on Cypress Creek's financing activities?

A That's not fair to say. I'm aware of their activities and what they're doing. That doesn't mean I review every presentation that they give.

CHAIRMAN FINLEY: Let me ask a question here. Mr. Culley, you have seen this -- Duke has shown you this exhibit before the hearing today?

MR. CULLEY: Just this morning, sir, yes.

CHAIRMAN FINLEY: Have you had an opportunity -- is it your opinion that this is a fraudulent document, that it didn't come from Cypress Creek?

MR. CULLEY: My opinion and the only information I've been able to gather is from what was told to me by Duke's counsel and from the screenshot, that it comes from a third-party website. That was not within the control of Cypress Creek, and that no one -- the witness is not directly familiar with this and cannot attest to --

CHAIRMAN FINLEY: I mean, I'm asking you, sir, if it's your position here that this is somewhat -- is a fraudulent document that, no matter how Duke got ahold of it, was not Cypress Creek -- it's not a real Cypress Creek document. Are you saying that this is a fraudulent document that somebody else prepared? I understand you maintain that to the extent that it was put on the Internet that somebody breached a confidentiality agreement for it to get there, but my question to you is do you maintain that this is not actually a Cypress Creek document?

MR. CULLEY: I maintain that, you know, I don't have a basis to confirm that it is. I see that it has a Cypress Creek logo on it and that it's currently being investigated, but my information on its authenticity is limited.

CHAIRMAN FINLEY: Let me ask you, what is your purpose for this document? What do you intend to show by it?

MS. FENTRESS: Mr. Chairman, Cypress Creek has indicated in response to a data request that it would share its financials with the Commission and with the Public Staff, and it has indicated that -- in its testimony that the Companies', Duke and Duke Energy Progress, proposals for the 10-year contract are not financeable. We asked the Company in several data requests to explain where they were coming from with financeability, unable to obtain this information, a Google search was embarked upon and we found information that we believe is responsive to some of the questions we had with respect to Mr. McConnell's testimony.

CHAIRMAN FINLEY: All right. I'm going to rule that Duke can, in the confines of the confidential portion of this case, ask questions on this exhibit provisionally. And, Mr. Culley, I want you to undertake an investigation and determine and let me know whether or not this actually was a document that was prepared by Cypress Creek for whatever reason, and that what is in here is what was prepared by Cypress Creek and has not been altered or plagiarized or falsified by somebody else. And once I know that, then we will determine whether or not the cross examination or any redirect examination on this exhibit shall be stricken from the record or not.

MR. CULLEY: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: All right.

MS. FENTRESS: Thank you, Mr. Chairman.

Q Mr. McConnell, could you turn to Slide 9. And I will say I have numbered the slides. The slide numbers when printed off the Internet were often faint, and so for ease, I have gone ahead and numbered the slides.

A Sure.

Q Thank you. Could you -- Mr. McConnell, let me just go back to the beginning of this document, Slide 1. And you will agree that the title of this document is "Solar Overview and Lending Opportunities"; is that correct?

A Yes, ma'am.

Q And with those type of activities, lending opportunities, solar, overview, would that be the type of work that you might have some involvement with?

A Sure.

Q And that would be the type of work that Mr. Thigpen would have some involvement with as your direct report?

A Yes, ma'am.

Q And I believe you said that one of your roles was to attract investors in the Company's projects; is that correct?

A Yes, ma'am.

Q And in going out and in trying to attract investors or interested parties into your projects, would it be reasonable to presume that the Company would provide or prepare a slide deck giving information on the Company's activities, developing solar facilities; is that correct?

A Yes, ma'am.

Q And would it be helpful for investors to see the type of financeable or the type of financing that the Company might do in order to develop these projects; is that correct?

A Sure.

Q And is it also correct that it would be helpful for investors to see the type of return on investment they might get if they were to invest in a Cypress Creek development; is that correct?

A Sure.

Q And so this type of presentation would be along the lines of those goals. Would you agree with that?

A Yes, ma'am.

Q Okay. And with that, can you please turn to Slide 9?

A Yes.

Q And I'm just going to ask you a clarifying question here. If you look, and it is a bit faint, at the picture at the diagram, it says 4.998 kW; is that correct?

A That is correct.

Q I'm going to move on to Slide 10. And would you agree with me that Slide 10 refers to a North Carolina utility scale facility; is that correct?

A Yes, ma'am.

Q And I believe you testified earlier that Cypress Creek does a lot of business in North Carolina; is that correct?

A Yes, ma'am.

Q And so you were -- this is an example that's in this slide presentation. Can I ask you to go to bullet number 3?

A Yes, ma'am.

Q And bullet number 3 provides a build cost of $10 million; is that correct?

A 10.5 is what I'm looking at.

Q 10.5. Sure. And it includes a soft cost of 1 million; is that correct?

A Yes, ma'am.

Q And so going back to the top where it says Example Utility, North Carolina Utility Scale Facility, let me just clarify. That says 7 megawatts DC. Does that translate to 5 megawatts AC?

A Yes, roughly. It depends on a project-by-project basis of what the build-out above AC, but yes.

Q Could it be 4.998?

A Sure.

Q And that would be eligible for the standard offer in North Carolina --

A Yes, ma'am.

Q -- is that correct? And so going back to, one, two, three, four, bullet number 5, will you agree -- well, I'm sorry, let me back up just a little bit. So we discussed the build cost of $10.5 million and the soft cost of 1 million. Would you agree that combined, that approximates an investment of approximately 11 million?

A Well, eleven and a half, but sure.

Q Okay. And then on bullet 5, it has Fair Market Value on Day 1, $15.4 million; is that correct?

A Yes, ma'am. That's what it says.

Q And what is Day 1?

A So Day 1 is the placed in service date of the project, and this -- again, this is as of a couple of hours ago the first time I've seen this document. The -- what appears to be in David's role is to incentivize other lenders that have taken advantage of a USDA program that offers a USDA guarantee for a portion of the loan that's made in support of the facility. In the process of doing that and putting this presentation together, they put a number of hypothetical assumptions in, one of which is an appraised value, and that appraised value takes into account -- from an appraiser, it takes into account a discounted cash flow of the projects using an income method over the 35-year useful life.

Q Thank you. And so just to follow-up on that, looking at that fair market value, so is it fair to say that that fair market value is approximately $4 million more than the investment that was made in this example?

A In this example, that is correct. I would not say that we have any experience with projects changing hand at that value. That is an appraised value for purposes of the financing.

Q So if I could move on, just in the explanation of fair market value, it says, "This number takes into account value of discounted cash flows." Is that the PPA with the Utility?

A Portions of the PPA, yeah. I think if this was a standard QF, it's assuming that 15 years are contracted, and the remaining term over the 35-year useful life is uncontracted.

Q Thank you. If you could turn to Slide 14, please. And if you could look at bullet number 3 and let me know when you're there.

A I am there.

Q Would you agree with me that bullet number 3 indicates that, "In regulated markets, the borrower is usually selling to rated off-takers." Is that correct?

A That's correct.

Q And then it also adds that, "These entities generally have a monopoly on electric power markets in certain areas" --

A Yes, ma'am.

Q -- "and are regulated on state and federal laws"?

A Yes.

Q And so fair to say that that refers to North Carolina Utilities --

A Sure.

Q -- Duke Energy Carolinas, Duke Energy Progress, and Dominion?

A Yes, ma'am.

Q Turn to Slide 16, please. And if you would go to bullet number 3, and it says, if you agree with me -- are you there?

A I am at bullet number 3 on page 16.

Q Thank you. "Cypress sponsor equity positions are funded through development fees or cash generated from the sale of projects." Is that correct?

A Yes, ma'am.

Q And so earlier you were talking about the sale of a project. What experience do you have with the sale of projects in North Carolina?

A It's not a function that I focus on at Cypress. We have a project sales team that does it to sell to other strategic buyers, Duke's unregulated side, Dominion, Southern, including some financial motivated buyers. We have -- that is how we finance our business in part by selling projects and recycling that into our development efforts.

Q And so going back to that 7 megawatt or 5 megawatts standard offer example that we discussed earlier, if that were sold on Day 1 at fair market value, would you agree that the cash that would be generated for Cypress Creek would be $4 million?

MR. CULLEY: I want to object here. I feel like, you know, we're departing from what's relevant to this case and, you know, looking forward to whether this is financeable under the terms and conditions that Duke is proposing. We're looking back here. So I just want to object to that.

MS. FENTRESS: It's directly relevant to the case. We have several issues in play in this case, and the first one is the financeability of the contract, and I believe it's directly relevant. And I believe, Mr. Chairman, you were discussing this the other day. When the Company enters into negotiations with a QF, the individual QF's ability to finance a project can be relevant to the type of -- can be relevant to those discussions and to the Commission's determination of the contract's length.

CHAIRMAN FINLEY: The objection is overruled. And Mr. Culley, you will have a chance to redirect this witness on this issue if you'd like.

MR. CULLEY: Thank you, Mr. Chairman.

Q And so go back to Slide 14, if I could take you back there to bullet point number 3. And I think we agreed earlier that that bullet point referred to North Carolina utilities; is that correct?

A In part, yes, ma'am.

Q And one of the descriptions given in that bullet point is that, "The off-takers are typically large corporates with massive balance sheets serving as a de facto credit tenant." Does it read that way?

A Yeah. Akin to the real estate world, a lot of our banks and lenders and financing parties are accustomed to financing real estate and looking at credit tenants and real estate transactions, and that's generally how we try to analogize our projects.

Q Would you agree with me under PURPA that the cost that the Utility incurs in purchasing PURPA power from a QF are passed along to the Utilities' customers?

A As I understand the market to work, yes, ma'am.

Q And so would you agree that the Utilities' customers, hospitals, schools, churches, are the true off-takers of this power?

A I guess. I mean, I assume so, if you want to make that connection. I view Duke as our customer, and where they distribute that power is at their discretion, and how they manage their customer load is not our -- our, you know, arrangement with them. We sell wholesale to the Utility.

Q And will you turn to page 13, please?

A Thirteen?

Q Yes. Can you -- it says Example P&L, and what does P&L stand for?

A Profit and loss.

Q Can you look down to where it says Gross Margin?

A Yes, ma'am.

Q And can you tell the Commission what that number says next to it?

A It says 82 percent.

MS. FENTRESS: I have nothing further.

CHAIRMAN FINLEY: Redirect, Mr. Culley?

MR. CULLEY: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: On this exhibit.

MR. CULLEY: Just on this exhibit, absolutely.

REDIRECT EXAMINATION BY MR. CULLEY:

Q So Mr. McConnell, we don't know exactly when this presentation was prepared, do we?

A No, sir.

Q But accepting it's true, Ms. Fentress' representation, sometime in 2015, would you agree this appears to have been based on avoided cost pricing in effect at that time?

A I would.

Q And would you assume that that also includes a 15-year contract tenor program?

A I would.

Q And if you were to model the fair market value for a standard offer project based on Duke's currently proposed avoided cost pricing and a 1 megawatt project with a 10-year PPA, do you have any reason to believe that the fair market value on the project on Day 1 would be materially in excess of the cost of constructing the project?

A I do not.

Q And Mr. McConnell, could you please explain exactly what that 82 percent represents again?

A Yeah. That is not Cypress Creek's operating margin. That is a farm level operating margin, and that's what is attractive about the farms. That revenue comes into the farms and there's a limited amount of line items in the P&L. As you can see, the O&M, insurance, rent to the site lessor, and the margins at the site are generally good, that 82 percent is then paid in large part to lenders which are, again, only interested in contracted cash flow generally and then the tax equity investors that get a significant share of the cash flow during their investment in the project. So I don't think it's necessarily fair to extrapolate that 82 percent margin to Cypress' general operating business of developing projects.

MR. CULLEY: Thank you, Mr. McConnell. I have no further questions on redirect on this exhibit.

CHAIRMAN FINLEY: All right. Do you have other questions?

MS. FENTRESS: I do not. My cross examination is completed.

CHAIRMAN FINLEY: You have no more?

MS. FENTRESS: No. No, sir.

CHAIRMAN FINLEY: We're going to -- somebody go out and tell the folks that we banished from the hearing room that we are going to come back at 2:00. The rest of you that have not been banished, come back at 2:00.

MR. CULLEY: And Mr. Chairman, at that time we will have an opportunity to redirect on the rest of the --

CHAIRMAN FINLEY: Yes.

MR. CULLEY: Great. Thank you. Thank you very much.

(The hearing was adjourned, to be reconvened at 2:00 p.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 148, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of 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 3rd day of May, 2017.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150