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TIME IN SESSION: 2:00 P.M. TO 5:10 P.M.

BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner Bryan E. Beatty
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 3

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CHAIRMAN FINLEY: All right. Let's come back to order, please. Ms. Bowman, you were looking at an exhibit that Mr. Ledford had given you, I believe.

THE WITNESS: Yes.

CONTINUED CROSS EXAMINATION BY MR. LEDFORD:

Q Ms. Bowman, I was just -- just going to ask you if you were aware of the materialization rates that were provided to us in a data response?

A (Bowman) So I've read the data response that you have provided.

Q Okay. So is it fair to say that based on DEC and DEP's previous experience, it's highly unlikely that the 4,900 megawatts will actually be connected to the grid and instead something significantly less will actually come to fruition?

A Well, I think it's hard to predict. I mean, I don't think every single megawatt will come online, but it's hard to predict.

Q But Duke does use these numbers in its integrated resource planning; is that correct?

A Well, I'm going to defer that to our Director of Resource Planning, Mr. Snider.

A (Snider) Yes. We reach out to our DER group and get their estimates of solar penetration. And given the uncertainty around those, we also run high and low sensitivities. Again, I think the thing that's missing in a resource plan from these materialization rates is also the fact that the queue has never been static. So it's not just how much of the 4,900 in the queue today come to fruition; it's what does that queue look like two years from now, four years from now, six years from now, and how much unknown comes to fruition as well, and that's why we run sensitivities.

Q And I guess, Mr. Snider -- well, yes, Mr. Snider. Just to be clear, when you say you reach out to the DER group, you are referring to Duke's internal Distributed Energy Resources, not Duke Energy Renewables, the separate arm?

A That is correct. It's our regulated group.

Q Thank you. Just for clarification since they share the acronym. I did want to ask a question that relates to the 4,900 megawatts that's currently pending in the queue and the various interconnection screens that are used during the interconnection process. Of that 4,900 megawatts -- I don't know if this would be best answered by Ms. Bowman or Mr. Freeman, but do you have an estimate as to how many -- how many megawatts of facilities will be eliminated through the circuit stiffness review screen or the voltage regulator screen?

A (Freeman) Well, your question is how many will be eliminated. If you remember, the circuit stiffness screen, you know, we started out with that being kind of a bright line screen, you know, where we eliminate projects, but as we worked with solar developers over many, many months, you know, we developed additional modeling capabilities for that screen, you know, to, you know, hopefully move those projects through, you know, in a more detailed, you know, kind of study methodology. So I can't say that that screen will eliminate any projects, per se.

Q Okay. In a data response, however, Duke provided to us an estimate of 700 megawatts or 140 facilities that would not pass or -- that have not passed or are anticipated not to pass the circuit stiffness review. Furthermore, approximately 330 megawatts or 75 facilities would not -- or excuse me -- are impacted by the voltage regulator limitations that are currently in place by Duke.

A Well, I think that's a better way of describing it, is they're impacted by the screen. You asked were they -- would they be eliminated. So they're impacted by the screen, which means that we need to do additional modeling for those projects.

Q And do you know how many megawatts of those projects that are in the queue are interdependent?

A No.

Q Okay. In a data response that I'd be happy to introduce, Duke told us that over 3,350 megawatts or nearly 280 facilities are interdependent with other projects on the queue -- in the queue. So is it fair to say that given those limitations, that it's highly unlikely that all 4,900 megawatts that are currently in the interconnection queue will come to fruition?

A Oh, I think that's an accurate statement. I mean, based on, you know, you know, this data that, you know, clearly the 4,900 megawatts will not all get built for various reasons. I think that's an accurate statement, yes.

Q Okay. Thank you. Ms. Bowman, I have just one more question related to your testimony about interconnection that's public, and then I do have a few questions that are confidential in nature.

MR. LEDFORD: So if it's okay, Mr. Chairman, I will hold those until the Panel is at its end.

Q And this relates to Figure 3 in your direct testimony which is on page 21.

A (Bowman) The North Carolina Solar Interconnection Requests by Year?

Q Yes. That's correct.

A Okay. I'm there.

Q Okay. One thing that this figure makes clear to me, at least, is that the number of interconnection requests and the megawattage of those requests peaked in 2014. Would you agree that that's accurate?

A Yes.

Q And since 2014, we have seen a decrease both consistently between 2015 and 2016 in interconnection requests, not megawattage, just the number of requests?

A So, yes, the number went down from 2014.

Q Yes. So the number went down, by my math, in 2015 to 242 interconnection requests, and then in 2016 even lower to 230 interconnection requests?

A Well, I'll -- I'll stipulate that your math is correct.

Q Thank you. However, as you noted in your testimony, the total number of megawatts developed increased from 2015 to 2016 from approximately 1,500 megawatts to just a hair over 2,000 megawatts; is that correct?

A Yes.

Q So it's fair to say that since the number of interconnection requests are going down, but the megawattage cumulative of those requests is increasing, those projects are getting larger on average?

A Yes. I think we have seen a increase in larger projects.

Q But the total number of interconnection requests has declined from 2014 to 2015 to 2016?

MS. FENTRESS: I believe that's been -- objection. I believe that's been asked and answered.

Q All right. I'd like to change gears for a minute now. Ms. Bowman, on page 8 of your rebuttal testimony you make note of comments filed by the EMCs?

A Yes.

Q So you make note -- you indicated that the EMCs are concerned in their initial comments about the undeniable cost increases; is that correct?

A That is correct.

Q What are the undeniable cost increases with which the EMCs are concerned?

A I believe it relates to the overpayments, as Mr. Snider has pointed out, the billion dollars. You know, the co-ops buy system average energy from -- from

DEC and DEP, and they pay for a portion of those costs. So they're -- it's my opinion that they're concerned about increasing costs when they're buying bulk power from us.

Q And you also note that the EMCs report that they depend on DEC and DEP's bulk power services, especially their transmission services, to serve the EMC customers in North Carolina?

A Yes. I say that on lines 16 through 19.

Q Has DEP experienced transmission congestion during any of the overgeneration events that have been discussed in Duke's filings?

A I am afraid I am not the person to ask about transmission congestion.

Q Okay.

MR. LEDFORD: Mr. Chairman, I'd like to pass out NCSEA Cross Exhibit Number 2.

CHAIRMAN FINLEY: All right. This exhibit that has been passed out is marked for identification as NCSEA Panel Cross Examination Exhibit Number 2, and let's call it NCSEA Duke Panel Cross Examination Exhibit Number 2.

MR. LEDFORD: Okay. Thank you, Mr. Chairman.

(Whereupon, NCSEA Duke Panel Cross Examination Exhibit Number 2 was marked for identification.)

CHAIRMAN FINLEY: And the other will be Duke Panel Cross Examination Exhibit Number 1.

Q Ms. Bowman, have you had a chance to look at the --

A I have.

Q Would you agree that it says that DEP has not experienced any transmission constraints due to overgeneration?

A Yes. It says not at this time, no transmission congestion.

Q Thank you. I'd like to change gears again and discuss a few of the things that you filed in your direct and rebuttal testimony about the Integrated Resource Plans. Before we broke for lunch when you were reading your summary, on page 7, lines 13 to 14, you noted that, and I quote, "The Company's resources are dispatchable and can be backed down when more economic alternatives are available."

A Yes. That is correct.

Q And if I heard correctly, Mr. Holeman, earlier when he testified, said that DEP has not curtailed its solar assets during overgeneration events?

A I believe he said he's not curtailed any solar assets, whether it was ours or a third party.

Q Okay. So that would include DEP-owned solar assets?

A That was my understanding of what Mr. Holeman said.

Q Okay. Thank you. And earlier I referenced the graph where you said -- excuse me -- the figure where you said that there's currently roughly 1,600 megawatts of third-party owned solar on the DEC and DEP systems; is that correct? And Mr. Snider, please feel free to jump in here, but I reviewed the Companies' Integrated Resource Plans from late last year, and DEP's IRP base case indicates that there will be -- anticipates 3,270 megawatts of solar on its system by 2031. DEC's base case anticipates 2,168 megawatts by 2031.

A (Snider) I'm sorry. I don't have the IRPs in front of me, but I will stipulate to that, subject to check, that the 2031 numbers that you cited in the base case are correct.

Q Thank you. I will ask this question of the Panel. I'm not sure who would best answer it, but are operational impacts examined in the Integrated Resource Plans?

A Not all operational impacts are examined in the

Integrated Resource Plans. The Integrated Resource Plans are 30-year planning models that look at the general economics and operating characteristics of a host of different generators. It is not a sub-hourly model. It is not meant to optimize operating reserves, ancillary services. It is not a reliability constrained model that Mr. Holeman spoke about that's looking at all the NERC potential regulations that have to be incurred. We take a much higher level approach when you look out over a 30-year horizon and multiple scenarios. So we do take into account the ramping capabilities of the units. We take into account their min load operating conditions, their maximum operating. So most of the general conditions of the generators are taken into account, but when it gets into the very detailed sub-hourly modeling, the IRP is not -- not the tool for that.

Q And Ms. Bowman, if you could turn to page 60 of your direct testimony.

MS. FENTRESS: I'm sorry, counsel. Did you say 60 or 16?

MR. LEDFORD: 6-0.

MS. FENTRESS: Thank you.

A (Bowman) What line?

Q In the initial paragraph, lines 4 through 8, you make note that qualifying facilities do not afford operational dispatch. So I would ask, Ms. Bowman, how much of the solar in the Integrated Resource Plans is anticipated to be utility owned that would be curtailable or dispatchable as opposed to QF owned which would be non-curtailable?

A (Snider) At this time, the IRP does not separate those two into buckets. That is probably a future development that the IRP will do, is if we start to see where we have a significant amount of solar that can be curtailed and dispatched on a -- as opposed to a must-take basis, we'll separate those. Up until this point in time we have not separated those into two separate asset classes.

Q So, Ms. Bowman, is it fair to say that the -- we've heard that the IRPs don't evaluate the sub-hourly operational impacts and they also don't take into account whether solar generation is curtailable. So would you say that the Integrated Resource Plans are actually investigating the needs of DEC and DEP over the next 15 years, particularly in light of the amount of solar development that is forecasted?

A (Bowman) I'm going to defer that to the Director of Resource Planning.

A (Snider) Yeah. I think that they certainly are. I mean, part of the reason this is coming to light is as the issues evolve and we see these operational needs and the impacts and they get reflected in our operational plans. So two years ago as we sat here in 2014, no one envisioned the level of non-controllable and the issues it would cause as quickly as it came on to the degree they did today. As we learn more about that and we evolve our modeling, we will in the future break those assets into a dispatchable and a non-dispatchable. It's the very nature of looking forward and saying if we don't have those dispatch rates, those -- I shouldn't say dispatch, but the curtailability of the control rates, what issues does that cause? You start with here's where we are today and then how does the world need to change once it starts to evolve to that, and we get an estimate of what's -- what's controllable, what's not. We'll break it into two different -- the two respective buckets.

Q IRPs aside, looking at the cumulative forecast for 2031, it's over 5 gigawatts of solar. Do the Companies have plans for how to deal with operational impacts at that time?

A I think that's what we're here discussing today. I think the answer is very different if you have half of that solar being curtailable, similar to -- so if you, for example, were out under an RFP and part of that RFP process specified you needed these curtailments, some of the telemetry and the communications that Commissioner Brown-Bland was speaking about, then that -- you would deal with it differently than if you didn't have those in place, and then you might have a different problem on your hands. So I would say that that is work in progress, and we -- we certainly -- part of the reason we're here today is to address that.

Q So Ms. Bowman, is Duke willing to share those plans with stakeholders?

MS. FENTRESS: Objection. I don't believe that question is clear. What plans are you referring to?

MR. LEDFORD: The plans that are being developed for how to deal with system impact -- the system operation impacts in the future.

A (Bowman) Well, I believe we do share those plans, the Integrated Resource Plan. I mean, we're here today talking about how we have seen an unparalleled growth in one particular type of resource and we need to make a change going forward. As Mr. Snider just pointed out, there is -- you know, if it comes to us as a must-take under PURPA and we don't have any curtailment rights over those facilities, then you need to address that in one way. That could be having to add more fast-start capability to your system. It could be having to construct large transmission lines to connect you to other balancing authority areas to manage that. There are multiple different ways you can address this problem. We're here today because we want to see a more managed, sustainable process going forward, one in which we don't have as many of these PURPA must-take with no curtailment rights involved and move to a more sustainable approach where we could have some dispatch rights over that. So I don't think 30 years from now we know how the policy of the state is going to evolve to be able to share those specific plans with you right now.

Q So Ms. Bowman, you moved well into my next line of questioning. In your direct testimony on page 23, Figure 5, I wanted to ask you a few questions about that figure.

A Okay.

Q And in your testimony on pages 22 and 23 you make reference to this figure, and you note that North Carolina leads all 50 states in PURPA solar, and I think that's well shown in this graph or in this figure. This chart shows the top markets across the 50 states for contracted utility solar projects that are outside of renewable portfolio standards. So as I understand it, this would not include compliance, REPS compliance projects in North Carolina, but I do note that there are four different categories of solar included in this figure. North Carolina has both PURPA and retail procurement quantities of solar on the grid. However, other states have voluntary procurement as well as wholesale procurement for utility scale solar PV. How much solar do DEC and DEP voluntarily procure?

A About 150, 200 megawatts. That is subject to check.

Q I believe -- I'm referring to the dark blue, almost black bar, and as I look at this graph, it doesn't appear that there is any voluntary procurement solar in North Carolina?

A Pursuant to this graph, that's what it appears.

Q Okay. And likewise, how much solar do DEC and DEP procure at wholesale based on this graph?

A We are a retail provider so we don't, I mean.

Q Okay. So I think it's fair to say that in this proceeding DEC and DEP have proposed some pretty sweeping changes to PURPA implementation in North Carolina that, by and large, would have the effect of discouraging QF development. So if that occurs, what markets, what opportunities would there be for continued development of renewables in North Carolina if there's not a voluntary procurement market or a wholesale market?

A Well, I don't believe we are completely eliminating the PURPA market in North Carolina in our proposal. I believe it is consistent within PURPA as well. And if you look at my direct testimony on page 61, and we have discussed earlier today, we are proposing to move to a new market for solar facilities outside of PURPA that would support growth of solar in North Carolina in a smart, sustainable way, and we talk about creating a competitive solicitation process, and we have asked for the Commission to initiate a separate proceeding on this.

Q Okay. I have a few questions about that competitive solicitation process for you, if that's appropriate. Are you -- are the Companies awaiting a decision by the Utilities Commission to open a docket on the competitive solicitation process?

A We have requested that the Commission initiate a separate proceeding.

Q So the Companies do not intend to file a petition to open a docket for that?

A At this moment we have requested a separate proceeding, so, no, we have not made a filing to open a separate proceeding.

Q Thank you. So why should we make radical changes in this docket to the PURPA paradigm when the RFP or competitive solicitation process has not been adequately or even minimally explained, if that's intended to be an alternative market for renewable energy?

A I think it's a new market. I wouldn't -- it's a new market and it's a different path forward for North Carolina for a smart, sustainable way. I believe we are at a crossroads now in this docket, as I've mentioned in both my direct and rebuttal, that we have enough facts before us that we need to make a change now. And PURPA affords states a great deal of flexibility. We have -- we've looked at other states and how they implement PURPA, and we believe PURPA provides for this flexibility, and we are at a position now in North Carolina where we need to make a change.

Q So it's accurate to say that there's no docket pending before the Commission regarding a competitive solicitation?

A I have said that before.

Q So what certainty do renewable energy developers have that this will come to fruition, a competitive solicitation will come to fruition?

A I cannot answer that. You know, that is up to the policymakers and perhaps the Commission of this state.

Q Thank you. I wanted to ask you another question that was referenced in the Companies' initial statement on page 36. In addition to recommending the Commission open a docket on a competitive solicitation process, this recommends the Commission open an additional docket on PURPA policies regarding additional modification to PURPA in North Carolina?

A Yes.

Q Is Duke again awaiting the Commission to open its own docket on this issue?

A Are you referring to quantification of solar integration and ancillary service costs and benefits as installed capacity increases?

Q Yes, as well as an evaluation of avoided energy and capacity rate that -- rate design in recognition of DEP's growing experience with midday solar energy production, evaluation of whether levels of non-dispatchable solar is quote, "useful capacity," end quote, that allows the Companies to reduce or defer future resource needs and for evaluation of continued appropriateness on the Commission's LEO policies.

A I believe these are things that we would investigate and potentially propose in future avoided cost proceedings.

Q Thank you. So I did want to return to a few questions about the standard contract as it's being proposed by the Utilities. One of the big changes that's referenced in your testimony is the change from a 5 megawatt threshold to a 1 megawatt standard contract system size threshold. Could you provide me with the Companies' justification for this change?

A Yes, and I believe I referenced this both in my direct and in my rebuttal as to why. You know, we have, again, done a lot of analysis, and we believe that the two primary drivers for our changing of PURPA implementation in North Carolina, and this is driving the reduction from the 5 megawatt down to the 1 megawatt. We believe that the 1 megawatt is a nice threshold. It fits within the FERC's qualifying facilities. If you're a megawatt and below, you don't have to file at the FERC for a QF status. It also allows the standard contract and avoided cost rates that we're discussing in this proceeding to be eligible for the small providers. We believe and we have noticed, and Gary Freeman can speak to this, that there's a lot of sophistication for the 5 megawatt and larger. We were also seeing, as you have brought to our attention, a lot larger facilities trying to connect. We also believe that the 1 megawatt will be able to go through this new fast track process that Mr. Freeman references in his testimony, helping out in the interconnection. So we believe that this is a good number as a reduction in North Carolina. We also are hopeful that it would encourage larger facilities to get constructed for economies of scale.

Q Thank you. You make note of the issue of staleness of rates in your testimony. What would the 1 megawatt threshold do to address staleness of rates?

A So for the large negotiated contracts, if you would be above 1 megawatt, you would be a large negotiated. In the negotiated space we are allowed to update with more accurate avoided cost data and fuel prices in the large negotiated, and so that helps to eliminate the staleness factor.

Q You also noted that, just a moment ago, that the 1 megawatt threshold, and you referenced Mr.

Freeman's testimony, that they're more likely to move through the fast track interconnection process without failing any of the screens. However, wouldn't that add to the administrative burden associated with the queue by increasing the number of projects under 1 megawatt?

A We do not believe it would, and I can refer to Mr. Freeman.

A (Freeman) I think that's true, you know, especially if these smaller projects can move through the fast track process much quicker than the larger projects.

Q So Ms. Bowman, you -- in your direct testimony you make note of Duke's desire for a more well-planned and coordinated process. This is on page 40 of your direct testimony, but it appears several times. What about the 1 megawatt threshold would allow for a more well-planned and coordinated process?

A (Bowman) So, again, that goes -- goes to being able to -- the larger QFs, you can negotiate those and you can eliminate the staleness, and it more accurately reflects up-to-date costs.

Q But it does nothing for the grid -- location on the grid, things like that?

A Well, that is why we're proposing the competitive procurement. In the competitive procurement process, if you look at my direct testimony on page 61, going to that direct competitive procurement process, that would provide DEC and DEP the ability to help locate in those locations that would make more sense on our system.

Q Thank you. I'd also like to ask you a few questions about the PPA term that's proposed for the standard contract. Several of the intervenors in their testimony, including NCSEA, expressed concerns about the need for a longer fixed rate than the two-year energy price refresh proposed by the Companies allowed. And we appreciate that the Companies responded to these concerns by agreeing to offer a 10-year fixed energy rate. However, I've got a question about how that rate is calculated. Is it Duke's position that offering a 10-year fixed energy rate based on two years of data is consistent with the Company's obligations under 18 CFR 292.304(d)(2)(ii)?

MR. BREITSCHWERDT: Objection. If you could put the regulation in front of her that you'd like her to consider, I think that would be appropriate, but to just throw out a citation is -- I'm not sure she can answer the question effectively.

Q While I get that citation -- while I get the text of the regulation, please, may I rephrase the question? So 18 CFR 292.304 says generally that fixed long-term rates for QFs are only just and reasonable and nondiscriminatory if they are equal to the utility's avoided cost. Based on how Duke is calculating its energy rates for that 10-year period, are the energy rates in Years 3 through 10 equal to Duke's avoided cost --

MR. BREITSCHWERDT: Here's the regulation.

THE WITNESS: Thank you.

Q -- for those years?

A We believe that we fit within the parameters of the Code of Federal Regulations and in compliance with PURPA with what we've proposed, both with the 10 and the two-year biennial energy reset and with the compromise proposal to offer the two-year -- the 10-year fixed rate with the energy component being fixed using our two-year energy data.

Q And just to be clear, under the compromise proposal, are the energy rates in the compromise proposal that are based on two years of data higher or lower than Duke's anticipated avoided cost in Years 3 through 10?

A I'm going to defer that to Mr. Snider.

A (Snider) They are slightly lower.

Q Thank you. I did want to ask a question also about capacity payments. In your -- and I'm going to reference your rebuttal testimony on page 33, specifically lines 14 through 16.

A (Bowman) Okay.

Q So here you note that, "FERC's PURPA regulations have long provided a method through 18 CFR 292.302 for QF investors to evaluate the utility's longer term need for capacity and forecasted cost of energy." And with that I believe you're referencing the filings that both DEC and DEP as well as Dominion have made in this docket. So is it accurate to say that FERC's regulations require the Utilities to file this avoided cost docket?

A Yes, and we do.

Q And isn't it true that significant amounts of Duke's filings are filed as confidential and redacted?

A I don't know if I would say significant, but I believe all parties can get access to that if they sign a confidentiality agreement.

Q So is it your opinion that QFs and investors can evaluate Duke's future avoided cost; they just have to petition the Commission to intervene in this docket and sign a nondisclosure agreement?

A I believe if they request it, they don't necessarily even have to intervene. I believe if they request it and sign a confidentiality agreement, they may have access.

Q Even market participants and investors?

A No. I think this is potential qualifying facilities, and if, you know, they're working with an investor and it is, you know, their agent or contractor and they sign a confidentiality agreement.

Q Okay. I have some questions also about the negotiated contracts. Oh, excuse me. Before I move on to that, I have one more question about the standard contract. Much of the discussion in this docket has pertained to solar qualifying facilities, but how will the Companies' suite of proposed changes impact non-solar qualifying facilities?

A Well, hydro is separate and apart from this and so, you know, if you're looking at -- I'm going to defer to Mr. Freeman for biomass and swine and poultry, but, you know, a lot of your large cogeneration, your steam host qualifying facilities, are much larger than the 5 megawatt anyway. So I don't think that that would necessarily, and this is just my opinion, have that much of an impact, but Mr. Freeman can...

Q Okay. Thank you, Ms. Bowman. And I would like to ask you a few questions about non-standard PPAs, if that's okay. On page 43 of your direct testimony, you reference a standardized set of Duke proposed terms and conditions. It's lines 17 through 19.

A Yes.

Q Given that Duke has developed a standardized set of proposed terms and conditions, how open is Duke to negotiating the terms of a non-standard PPA?

A I mean, we're open to it. We're proposing the standardized terms and conditions to streamline the process. You know, there was complaints in previous proceedings that it was difficult and protracted negotiations, and so we're trying to develop these standardized terms and conditions to ease that process.

Q Are there particular provisions that Duke will negotiate?

A I believe I just said we would be willing to negotiate, but that we were streamlining the process with the standardized terms. I mean, each facility can have unique characteris--- characteristics.

Q Could you explain what you mean by standardized terms and conditions?

A You know, in my mind, it's the general terms and conditions of the contract. You know, it could range from your creditworthiness criteria, your boilerplate legal language. I mean, to me, that's your standardized terms and conditions.

Q So given that Duke has standardized and -- these terms and conditions, is Duke open to Commission -- the Commission approving this contract that's used for larger QFs?

A I'm going to defer to Mr. Freeman.

A (Freeman) Yeah. I think I'll answer your question this way. I mean, we've worked with a number of developers that early on had these larger non-standard contracts, and we've evolved to what we feel like is a fairly appropriate stan--- I'll call it a standard contract with standard terms in it. So, I mean, I feel like, you know, as time goes on, we're going to continue to learn more about what's appropriate in that contract, and I feel like we will potentially evolve from time to time with other terms as they need be.

I guess my first thought is that, you know, the answer would be no. I would hope that this is a contract that we're negotiating between, you know, QF developers and the Utility. I feel like you would, you know, potentially overburden the process by every time you wanted to make a change in a negotiated contract having to bring that before the Utilities Commission.

And to date, just for the record, I don't have the exact number, but we have executed over a dozen, you know, non-standard negotiated contracts. So I think with the developers we've worked with, we've been successful at executing contracts that work for both the developer and for the Utility.

MR. LEDFORD: Thank you. And I've got a question about one of the provisions in that, specifically the term of the non-standard PPA. And Mr. Chairman, I'd like to pass out NCSEA Cross Exhibit Number 3.

CHAIRMAN FINLEY: All right. This next exhibit shall be marked for identification as NCSEA Duke Panel Cross Examination Exhibit Number 3.

(Whereupon, NCSEA Duke Panel Cross Examination Exhibit Number 3 was marked for identification.)

MR. LEDFORD: And this is the cover page as well as a slide from a presentation that I believe Mr. Freeman and Ms. Bowman together gave to a legislative group in February.

Q And I'll note that on the second-to-last line of Slide 7, which is on the back of the exhibit, one of the key terms of the negotiated PPA is that the contract term would be reduced to a period of two years. Is this accurate?

A (Freeman) I think at the time that we made this presentation it is accurate, yes.

Q Are you saying that Duke no longer has plans to reduce the term to two years?

A I didn't say that. I think over time, you know, if we feel like the need justifies moving to a 2-year term contract, we would move to that, similar to what we did when we moved from a 10-year term contract to a 5-year term contract.

Q So if the Commission grants the suite of proposals made by Duke in this proceeding to reduce the standard offer eligibility to 1 megawatt, anything in excess of 1 megawatt must negotiate a contract. So for QFs that are currently between 1 and 5 megawatts, this would mean they would be going from a PPA term under E-100, Sub 140 rates of 15 years to a negotiated contract with a term of two years?

A Or five years.

Q Or five years. Okay. Thank you. So, Ms. Bowman, I have a question that relates to something that was brought up with Witness Holeman this morning before lunch.

MR. LEDFORD: And Mr. Chairman, I'd like to pass out NCSEA Cross Exhibit 4, which is an excerpt from Duke's 2014 PNNL study on solar PV integration.

Q I'd like to draw your attention to Footnote 3 on the bottom of the page of text.

CHAIRMAN FINLEY: This next exhibit is marked for identification as NCSEA Duke Panel Cross Examination Exhibit 4.

MR. LEDFORD: Thank you, Mr. Chairman.

(Whereupon, NCSEA Duke Panel Cross Examination Exhibit Number 4 was marked for identification.)

A (Bowman) Okay. I have read the footnote.

Q Thank you. So the footnote makes note of the fact that PNNL, at least, believe there could be some operational benefits to combining DEC and DEP's balancing areas, correct?

A It says that, "Combining the two BAs or coordinating their balancing operations could potentially reduce the challenges from variable resources on generation operations, and is a subject for further studies and opportunity for operation improvement."

Q And I believe these questions were asked of Mr. Holeman this morning and he was not aware of the answer, but has Duke performed any such investigations?

A Yes. Duke has looked at combining -- and it's technically three balancing authority areas. We have CP&L East, CP&L West which is up in the Asheville area, and then DEC. Collapsing into one balancing authority area does not necessarily solve the operational challenges that we're facing. It is also a complex process and it takes a number of years to complete. It requires NERC and FERC approval, as well as approval from this Commission. It is very complex to just collapse. So, you know, the issues that we are facing today and in the near term future, this would not resolve those problems. Is this something that could potentially farther out in the future, it could help, but, again, it doesn't solve all of the problems. It's more legal in nature in collapsing the balancing authority areas. It does not change any of the physical in terms of the size of your transmission and interconnections stays the same. So the physical limitations remain the same. So that's how I would answer that.

Q Thank you. And, Mr. Snider, I believe that the 2016 IRP did look at a joint planning scenario as well,

correct?
A (Snider) Yes. We didn't look at it from the legal definition of collapsing BAs; we just looked at it as if we were to have a future generation plan that was covering both Utilities, what that might look like just for -- as a sensitivity within our planning process.
Q Thank you. So Duke did examine it if not in quite the same manner; is that fair?
A Yeah. That's on a much, much different level than what Ms. Bowman was speaking about. This was just, say, if we could build future resources together, how would that look like versus building independent resources for the two legal entities.
Q Great. Thank you.
MR. LEDFORD: So now if I could, I have a few more questions for Ms. Bowman that are confidential so I'll wait until later. I do have a few questions for Mr. Freeman, though.
Q So Mr. Freeman, I've got a few questions about interconnection. Do you know how much QF developers have paid in interconnection facilities and upgrade costs to DEC and DEP?
A (Freeman) I believe that's in some of the testimony. I think the total that's been paid is roughly

$25 million, if I'm -- if I'm not mistaken, subject to check.

Q And that's for both upgrade and interconnection facilities costs?

A Correct. I'm not looking at testimony, so maybe -- you're looking at me strange like maybe I'm off by a particular number, but if you'll direct me to -- I know it's in the testimony.

Q If I could read to you a joint DEC and DEP response to a data request.

A Sure.

Q The Companies responded that the following answer includes projects 2 megawatts AC and greater, locations in North Carolina and South Carolina, distribution only, and solar and non-solar resources. For DEC, the total upgrade and interconnection facilities costs are $16 million -- $16,002,415. For DEP, the total upgrade and interconnection facilities costs are $52 million doll--- $52,000,937.

A Okay.

Q So by my math, that's a touch over $68 million.

A Okay.

Q This was interconnection costs for distribution only and 2 megawatts or greater. Do you know what the --

MR. BREITSCHWERDT: Mr. Ledford, if you're going to have extensive questions on this data request, would you mind showing it to the witness so he can see the full response, please, or identify it for counsel so that we can get it from our files?

MR. LEDFORD: I'd be happy to. It's the joint company response to NCSEA Data Request Number 2-13.

(Off-the-record discussion.)

MR. BREITSCHWERDT: That's great. I just wanted him to see what was said. Thank you. Just allow him a moment to read it, please.

A Okay. I've read it. So I stand corrected on my answer.

Q Thank you, Mr. Freeman. Do you know what the upgrade costs have been for transmission connected QFs?

A I don't know what the total has been, but I know there have been projects where the upgrade cost has ranged from anywhere from 10 to $40 million on a particular project.

Q And do you know what the interconnection facilities costs have been for transmission projects?

A I'm kind of going roughly, but by the time you tap the transmission line, build a switching station, I think those costs are in the one and a half to $3 million range, if I'm not mistaken.

Q So while it's true that these investments may have -- may -- excuse me. While it's true that these investments may not have been made but for the interconnection of qualifying facilities, do customers benefit from these upgrades?

A They do not benefit from the interconnection facilities payments. They potentially benefit somewhat from the upgrade cost, but that depends on a project-by-project basis.

Q Thank you. I also wanted to ask you a few questions about the studies that were referenced during Mr. Holeman's cross examination this morning. If you will recall, there were discussions about I believe it was four different studies on operating -- studies about operating the system and various scenarios of solar PV penetration. Witness Holeman testified that he isn't familiar with those studies, that they didn't go to the operational impacts that are the driver of Duke's proposed changes in this docket. If these studies aren't used by Duke system operators, who in Duke does use them?

A Well, these studies that you're referencing have been done to start informing the Utility as to what future integration costs may look like as we experience deeper and deeper penetrations of solar primarily.

Q So Mr. Holeman testified this morning that he certainly, and presumably DEC and DEP were aware as early as 2014 through participation in the NERC task force upon which he was a member, about these system operational impacts. Why didn't Duke study the issues that would benefit the system operations today?

A I'm sorry. Ask that -- why didn't we --

Q Why didn't Duke study the impacts that Mr. Holeman discussed?

A Well, I think in that PNNL study, we looked at, you know, dispatch -- you know, changes in dispatch. We looked at some of the -- I think that first study looked at some of the ramping issues and the cost to, you know, run the system, you know -- you know, the generation system differently, and that's where some of those costs come from, that PNNL study. So if you remember the PNNL study, we studied multiple scenarios ranging up to roughly 7,000 megawatts penetration. If you look at that first study, at the time that the assumptions that went into that study were made, it was probably 2012, early 2013, before those assumptions were made. So at that time we looked at a much, much heavier penetration in the DEC system than we did the DEP system. And the result of the study show that as penetration gets higher and higher, that we're going to -- at least the study validates what we're seeing or what Mr. Holeman is seeing, that there are cost impacts. Most costs in that study ranged, as I recall, anywhere from $2 a megawatt hour up to almost $10 a megawatt hour as you get up to the deeper penetrations.

Q So am I correct in hearing that Duke did study the issues raised by Mr. Holeman, but that those studies have not been used by system operators?

A Well, we've studied some of the impacts I think that Mr. Holeman is seeing today.

Q Thank you. In your testimony you also lay out the proposed changes to the LEO standard, the legally enforceable obligation standard. I just wanted to ask a few questions related to your proposal. What penalties are there if Duke delays sending a system impact study to the QF, which would then delay the QF obtaining the LEO?

A Today there are no penalties, you know, imposed on the utility for not meeting, you know, the interconnection standard, but --

Q Thank you.

A -- you've got to keep in mind that, you know, that standard never contemplated the amount of projects that we have in the queue today and, you know, Duke makes a -- a reasonable attempt to try to meet those standards. You know, we've gone from one to two employees in the DEP system, one to two employees in the DEC system to where we've now got 30 -- roughly 30 employees doing nothing but system impact studies for the system. And if you look at my testimony, I've referenced that those studies are getting more and more complex and complicated. The upgrade costs are getting higher and higher, which is challenging us to, you know, to try and meet those standards.

Q There are no penalties if Duke delays a system impact study -- if a system impact study is delayed?

A That is correct.

Q Thank you. So it seems to be with the standardized contracting procedures that you lay out in your testimony that there needs to be a PPA entered into before a LEO is established under these procedures; is that accurate?

A That's correct. We're -- you know, we're concerned that, you know, under the current LEO policy that a QF is not making a binding commitment to sell to us, and we feel like the most prudent way to kind of bind a commitment from both the Utility to accept the generation and the QF to provide the generation on a specific date is through an executed Power Purchase Agreement.

Q And currently under the negotiated contracting procedures that we have, the notice of commitment expires after six months; is that correct?

A Subject to check, yes, I think that's correct.

Q And NCSEA recognizes and acknowledges that staleness is an issue, but in the past, the Utilities Commission has said that the 30-month rule is appropriate in that it is appropriate for handling the staleness issue, correct?

A That's correct.

Q And have you had a chance to read NCSEA Witness Harkrader's testimony?

A Yes.

Q And her testimony pointed out that a QF does not benefit from a delay; is that correct?

A You'll have to point me to that reference in her testimony.

Q That's fine. I'll withdraw it. So it's fair to say that through all of this, it gives the Utility a lot of discretion in the contracting procedure; is that correct?

A Which contracting procedure are you referencing, the interconnection contracting procedure or the Power Purchase Agreement?

Q The non-standard PPA procedure.

A I mean, ask your question again. I'm not following you.

Q So the Utility controls the system impact study which is a prerequisite to establishing a LEO, correct?

A Well, that's what we initially proposed was that, you know, you would execute a Power Purchase Agreement once you executed a facilities agreement study. You know, we have since, you know, kind of modified our proposal and we're proposing a contracting process.

Q And under the modified proposal that you put forward, if a PPA was not entered into, then arbitration could occur before the Commission and the Commission would decide when a LEO was established; is that correct?

A That's correct.

Q Okay. So if the Company and the QF cannot reach agreement on a negotiated PPA, then it would be up to the Commission to establish -- to determine when the LEO was established?

A That's correct.

MR. LEDFORD: Thank you. Those are all the questions I have.

CROSS EXAMINATION BY MS. MITCHELL:

Q Good afternoon, Mr. Snider. How are you? Charlotte Mitchell for NCSEA.

A (Snider) Hello, Ms. Mitchell.

Q I have some questions for you regarding your testimony in this proceeding. Mr. Snider, in this -- in this proceeding Duke and Progress, or DEC and DEP, take the position that its customers are overpaying for QF generation in light of declining avoided cost; is that correct?

A Yes.

Q Okay. And you testify in your direct testimony on page 4, lines 4 through 6, that there is, "...a potential long-term overpayment of approximately $1.0 billion by customers compared to the Companies' current calculation of its avoided cost rates proposed in this proceeding." Is that correct?

A That is correct.

Q Okay. And Mr. Snider, I'm assuming that you have the Companies' Initial Statement filed in November in this docket, but on page 6 of that Initial Statement --

A Okay.

Q -- the Companies appear to question the prudence of --

A I'm sorry. What line?

Q Page 6 -- is it -- are there lines?

A Oh, it doesn't have lines. Sorry. Go ahead.

Q Okay. The Companies appear to question the prudence of 15-year contracts by stating that, "DEC and DEP have long-term PPAs with Commission-set avoided cost rates ranging from $55 to $85 per MWh while the Companies' current actual system incremental 'avoided' costs are approximately $35 per MWh." Do you see that in the --

A I do see that.

Q Okay. And are you aware, Mr. Snider, that in response to a data request, DEC and DEP explained that the $55 and the $85 per megawatt hour figures are based on PURPA projects that are interconnected or under construction, including large and small QFs, so existing QFs selling to the Company or to sell to the Company?

A And, yeah, that's subject -- subject to check. Yeah. That's existing or those that have legally enforceable obligations that entitle them to those rates that are yet to come online.

Q Okay. Understood. Thank you. Mr. Snider, don't those figures, the $55 per megawatt hour and the $85 per megawatt hour, reflect 10 and 15-year forward looking levelized rates that include both energy costs and capacity costs?

A They do.

Q Okay. And doesn't the $35 per megawatt hour represent a weighted average hourly cost observed during the year 2015?

A Yeah. That would be -- I did not provide that on the initial statement, but I'm assuming that's correct. My testimony refers to, in my rebuttal, a incremental cost in 2015 of about 30 -- I believe it was -- if you'll give me a second, I'll look at my rebuttal.

MS. FENTRESS: While Mr. Snider is looking at his rebuttal, may I ask counsel, if you're referring to a data request, could you put it in front of the witness and the attorneys?

MS. MITCHELL: Yes. I will do that.

MS. FENTRESS: Thank you. And can you identify the data request, too, for the record?

MS. MITCHELL: For the record, it's the DEC and DEP response to North Carolina Sustainable Energy Association Data Request Number 1-11.

A Okay. I see that.

Q Okay. So Mr. Snider, isn't the $35 per megawatt hour just a single average cost estimate from 25?

A It's not an average. It's a marginal cost of electricity. I don't think that was our average cost of electricity.

Q Okay. Understood.

A Average marginal.

Q Okay. And does this -- doesn't the $35 per megawatt hour marginal cost reflect just the cost of energy at the margin?

A Yes.

Q And does not reflect capacity costs?

A I think that was the illustration given in the statement. That is not the number I based my calculation on. When I refer to an overpayment, I was not referring to just the marginal cost in 2015. I think that was just making a comparison of here's what we're paying and here's what our marginal cost of electricity was. And we had no incremental need for capacity in that year, so, yes, we were paying these prices while we were generating on the margin for these prices. We were not saying that that was the basis for -- the complete basis for overpayment risk. It was simply an illustration of what we're paying for QF energy and what we're generating for on the margin.

Q Okay. Understood. But to be fair, what you're paying QFs includes a capacity cost while what you're paying for energy on the margin does not?

A That is correct.

Q And the QF -- what you are paying to the QFs is forward looking 10 to 15 years?

A That is correct.

Q Okay. Thanks. Okay. Mr. Snider, in your direct testimony on pages -- on page 25, you testified generally -- and I'm looking at lines 3 through 10 -- that solar generation may cause a need for additional generating capacity. Is that -- is that a fair characterization of your testimony?

A I'm sorry. Let me read that section. You're on lines 3 through 5 of my direct on page 25?

Q Actually, 3 through 10 --

A Three through 10.

Q -- on page 25.

A Okay. I've read that. Please re-ask your question.

Q Okay. So my question was in general, you're testifying that solar generation may cause a need for additional generating capacity; is that correct?

A I don't think I'm saying that in that statement. I'm saying what generation is added needs to be more flexible. It needs to be faster ramping, faster moving, lower mins, more flexible generation as Witness Holeman described.

Q Okay. Fair enough. And do you testify anywhere in your direct or your rebuttal testimony that solar generation may cause a need for additional generating capacity?

A I don't recall saying we need more generation other than we may need more flexible -- that we may need more operating reserves in terms of how we deal with that uncertainty that Mr. Holeman spoke about, but I don't think I went into -- into that in my testimony.

Q Okay. In lines -- looking again back at lines 8 through 10 on page 25 of your direct testimony, you specifically reference the fast-start CTs at Sutton, runner upgrades at Bad Creek Pumped Hydro Station, dual fuel optionality at Cliffside, and the recently announced expansion at the Lincoln County CT site; is that correct?

A Yes. I see that.

Q Okay. And weren't these projects -- weren't all of these projects planned well in advance of the growth of solar development in Duke's service territories?

A Let me walk through them one by one.

Q Okay.

A I think in our fast-start CTs at Sutton, we obtained a CPCN and those were black start fast-start resources that were needed for reliability. We pointed out, I believe, in our discussions through that CPCN process a additional benefit would be their faster ramping capabilities and how that would integrate well with solar on that part of the grid. So those were not built -- very clearly not built because of solar. They were built as black start resources to serve as a NERC black start reliability resource, but we did point out in our CPCN that those would be beneficial for solar.

The Bad Creek Pumped Hydro is a very cost effective way to add more pump storage where you can upgrade through the relicensing process and get additional capacity out of your pumped hydro. We point, I think, in our -- in that project when we pointed out the potential for that one of the main benefits with that is we would have additional pump storage capability that would help us better integrate renewables on the grid. So we did talk about that.

Dual fuel optionality at Cliffside, that has been a recent project as well. That's talking about adding -- not burning natural gas solely, but having a dual fuel optionality to be able to burn either coal or gas. That does improve the operational characteristics of that facility which, again, in total helps. The more flexibility you add to the system, the more able you are.

And so I think Mr. Holeman pointed out that more flexibility helps him. So that was not justified as a -- we're putting it in to accommodate solar, but we point out one of the benefits is that it will help with solar.

And the Lincoln County CT site that we speak about, the expansion there is a state-of-the-art simple cycle turbine that does have some of the fastest ramping at the current technology levels in the industry.

So, yes, it's hard to say that -- you know, I'm not saying that we're building all of these projects, that we did not have a capacity need, and that solar was driving us to build projects we otherwise would not have built. I'm just saying that we're adding flexibility to the fleet in an attempt to be able to have faster ramping capabilities.

Q Okay. Thank you. That's a helpful

explanation. So Mr. Snider, to the extent that you remember off the top of your head, do you know when the CPCN for this black start CT was issued that you reference in your testimony?

A I do not.

Q Okay. Did that black start CT appear in the Duke Energy Progress IRP in 2012?

A I do not believe it did in 2012, but I'm going to say that subject to check.

Q Okay. And Mr. Snider, will you confirm that the Cliffside facility, the Bad Creek facility, and the Lincoln County facilities are in DEC's service territory, D-E-C service territory?

A Say your list again. I'm pretty sure you're correct, but go through it slowly for me.

Q Cliffside --

A Yes.

Q Cliffside, Bad Creek, and Lincoln County.

A Yes. Those are all DEC assets.

Q Okay. So Mr. Snider, is it fair to say that Duke has given some consideration to how to manage solar generation in its systems using other generating resources?

A I think it's fair to say that we have

recognized that having more flexibility, given what's facing us with intermittent generation, is a good thing, yes.

Q Okay. Thanks. Mr. Snider, will you please turn to page 14 of your rebuttal testimony?

A I'm there.

Q Okay. I'll point you to lines 10 through 20. In these -- in this portion of your rebuttal testimony you explain the compromise that Duke and Progress are offering regarded to the resetting of the energy rate; is that correct?

A I do.

Q On lines 16 through 20 you explain that the compromise is offered in response to testimony from intervenors, that small QF investors will view energy revenues beyond the -- beyond the biennium as risky and that a longer term fixed rate is needed by smaller QFs in order to attract capital. Is that an accurate characterization of your testimony?

A Yes. I'm representing that's what intervenors are claiming.

Q Okay.

A Yes.

Q And Mr. Snider, how are you defining small QFs in your testimony? How do you --

A One megawatt and under.

Q Are you aware of whether DEC and DEP intend to use a two-year resetting energy rate with large QFs, any QF that's greater than 1 megawatt?

A On the negotiated contracts I'm not aware of -- I've heard Mr. Freeman say that it could be five years, it could be two years, and I was looking at the exhibit that was put in front of him, but, no, I'm not --

Q My question is specifically a resetting avoided energy rate.

A With the large QFs?

Q Yes.

A No. I think what Mr. Freeman said was with the large negotiated it would be between a two and a five-year term.

Q So a fixed rate over that two and five-year term is what you're saying?

A That's my understanding. I will say I'm not the expert on that, I'm not the one negotiating those, so I'm going to defer to Mr. Freeman.

Q Okay. I'm going to have you flip back to your rebuttal -- to your direct testimony, pages 32 and 33. These pages, Mr. Snider, as you get there, this is where you discuss what I refer to as the Companies' proposal for relative need for capacity.

A Yes. Just give me one second to review that section.

Q It's pages 32 and 33.

A Okay.

Q Okay. So as I understand it in this proceeding, DEC and DEP propose that the Companies' relative needs for incremental generating capacity should be taken into account when calculating avoided capacity rates; is that correct?

A That is correct.

Q Okay. Further, in calculating avoided -- avoided capacity cost, no value should be ascribed for years in which there is not an avoidable need. Is that -- is that Duke and Progress' position?

A Let me be clear when I say value versus payment. So when you calculate the value over a 10-year contract for 1 megawatt and under, you would pay a capacity payment in every year of that 10-year contract. In ascribing how much value that 10-year contract creates, you would not start ascribing value until there was actually a capacity need to be deferred or avoided.

Q Okay. Thank you. So put another way, DEC and

DEP propose to include zero value for avoided -- avoided capacity in years when their respective IRPs show no capacity need?

A When there is no resource that can be avoided. I don't know that I would -- if I've said it that way, it should be is there an avoidable resource. So until you have an avoidable resource or a deferrable resource, then you would not have a value.

Q Okay. And as I understand it, DEC's and DEP's justification for their proposal, generally stated, is that its customers shouldn't be required to pay for capacity in years in which the Companies have already built or procured sufficient capacity to serve their customers; is that correct?

A I'm sorry. Can you refer me -- is that a general statement or is that in my --

Q It's a general statement. It's my characterization of your testimony.

A Say it one more time. I apologize.

Q Okay. It's my understanding that Duke -- that DEC's and DEP's justification for their proposal, generally stated, is that its customers should not be required to pay for capacity in years in which the Companies have already built a procured sufficient capacity to serve their customers; is that correct?

A Yeah. I think I understand that. I guess what I would say is it's my understanding that PURPA says you shouldn't pay for something you're not going to see value in. So if there is no need for capacity, you shouldn't be paying as though there was a need. And so that -- if that's -- if we're on the same page on that, then, yes, that's what I implied.

Q Okay. Thank you. Do you agree that this proposed change to the way in which the avoided capacity cost is calculated results in a nearly 60 percent decrease in the annualized capacity credit for both Duke and Progress?

A I'm sorry. Is there a data request? I don't have that number in front of me. I know it did result in a -- in a reduction. I think I did mention that somewhere. But subject to check --

Q Okay.

A -- I can say it resulted in a decreased capacity value.

Q And I can refer you and your counsel to the DEC and the DEP response to Public Staff Data Request 2-21.

A Okay. I'll stipulate, subject to check.

Q Okay. Thank you. Mr. Snider, are you aware that in discussing the application of the peaker method in North Carolina, this Commission has recognized that avoided capacity costs should equal the cost of the hypothetical CT together with the marginal system running costs, and that together these will equal the cost of any generating plant, including a baseload plant?

A In times when there is a need, yes. The two need to be inextricably linked if there's a need for both capacity and energy. If there's not a need -- and, you know, the easiest example is what if we are in a situation for over the next 10 years there was no need on the system? Clearly, anybody coming onto the system as a QF would still avoid fuel payments for the company, and so a marginal energy payment would still be reasonable, but if they had no capacity need over that 10-year period, there would be no reason.

And it's certainly not the intent of the peaker method to say I've got to pay you both capacity and energy for the peaker method to still hold true. So all we're saying is while we might not have -- we have a need, it's not over the whole 10-year period, so you need to prorate it for when there is a need. So, yes, I believe we're still very consistent with the peaker method, and I believe that what we've proposed is compliant with how -- the intent of that methodology.

Q Okay. Thank you. I'm going to ask my question one more time and I'm going to draw your attention to the Commission's Order Setting Avoided Cost Input Parameters issued in Docket No. E-100, Sub 140 on December 31, 2014.

MS. MITCHELL: I would like to approach the witness and show him the Order, if that's acceptable.

CHAIRMAN FINLEY: You ask me.

MS. MITCHELL: Yes, sir.

MS. FENTRESS: Mr. Chairman, we'll stipulate to what the Order says. The Order says what it says.

MS. MITCHELL: Okay. Fair enough. Thank you.

Q And Mr. Snider, you agree that the Order says what it says?

A I do.

Q Okay.

CHAIRMAN FINLEY: That's a good thing.

Q Okay. Mr. Snider, is it DEC's and DEP's position that including zeros for years in which the Utility does not have an avoidable capacity need would result in avoided cost rates that compensate the QF for the full cost of a CT plus the system marginal running costs?

A Starting with the first year need, it most certainly would.

Q And has -- have Duke and Progress offered any calculations or data supporting this position?

A I think we've stated -- in both Sub 140 and Sub 148 we went into a pretty large data request and discovery on that the capacity rate is set based on exactly those parameters.

Q And so in this proceeding, in this docket, have -- has Duke or Progress offered data or calculations supporting this position?

A Yes. I believe we have. We've said here's our cost of a simple cycle turbine based on the most recently available data, here's what the carrying costs of that turbine are, including all fixed operating and maintenance costs, ongoing variable cost, and we've put that forth in multiple data requests, and it's the genesis for how we calculate capacity values starting in the first year of capacity need.

Q Okay. Mr. Snider, do you agree that the theory underlying the peaker method is that the summation of the capital cost of peaking capacity and the system marginal cost will match the cost of any capacity, assuming the Utility's system is operating at the optimum point?

A I think I have attempted to answer that. I'm hoping I'm understanding you correctly. It's my position that when there is a need -- you know, as a resource planner, you know, I think what we always think about is we can always build a peaker, right? You know, the whole assumption behind the peaker method was you build a peaker, it never operates, it's just capacity. This is when the peaker method was first evolved. And then you just rely on your system marginal energy cost for the energy. And the combination of those two allows you to have both the capacity of the peaker and the energy of the system. And so before you ever go to build something that costs more than the peaker itself, you say am I creating enough energy value to pay for the incremental capital to go to the more expensive unit. That's the whole genesis behind the peaker being a proxy for any baseload unit, is before you spend more capital for a baseload unit, you will generate more marginal fuel cost.

So in this proceeding, we've said that we are giving full marginal energy value starting from Year 1, like any -- like the peaker method prescribes, and then in the first year of need, we are also ascribing capacity value. So, yes, I think this fully comports with the peaker method as being the proxy for any other unit on our system. Whether our next unit five years from now, seven years from now, is a combined cycle, whether it's a CT, whether it's a baseload unit, the peaker method still is applicable as applied in the situation you describe.

Q Thanks, Mr. Snider. Is it -- is it DEC's and DEP's positions that their systems are no longer operating at the optimum point?

A I would say that their -- their systems are operating, you know, effectively. I don't know what the -- what your -- give me your definition of optimum point.

Q Well, I'm just quoting from the Commission's Order. So we'll move on.

Mr. Snider, did the Companies' capacity additions always match the resource plans set forth in the IRP?

A I'm sorry. Can you be more specific? What -- so certainly we have solar coming on at much different rates than the IRP, you know. It's some -- that's why we run sensitivities on it. So, yeah, we get a different amount coming on than expected at times.

Q What about the Lincoln County CT that you've recently applied for a CPCN application? So my understanding is that an application for a CPCN for a natural gas fired combustion turbine has been filed by DEC in Docket No. E-7, Sub 1134.

A That's correct.

Q Is that -- does that resource appear in your IRP?

A Which IRP are you speaking of?

Q The DEC IRP.

A The 2016 IRP?

Q Does it appear in the 2016 IRP?

A I don't have my IRP in front of me. I would have to check what year our first need was in 2016.

Q My question is, does the Lincoln County CT site appear in any of the DEC IRPs?

A I do not believe it does.

Q Okay. Thank you.

A And I will point out that when we put the Lincoln County CPCN -- because even though it's at a different site, we recognized that if you want to build capacity early, we essentially gave the Lincoln County CT zero capacity value in those first years until we had a need. So consistent with what we're arguing before the Commission here today is we said that we need to build that project economically enough to encumber those costs for two years at a cost so discounted that we can then still have it make sense over the life of the project. So in essence, we did ascribe in that CPCN no capacity value until the first need and said it still has to be the most prudent and economic option for our customers in order to justify it before the first year of need. So I would just say there's an example in integrated resource planning in practice where we did apply zero capacity value prior to having a natural need.

Q Mr. Snider, are you familiar with the Western Carolinas Modernization Project?

A Yes.

Q Just wanted to make sure. And are you aware that related to the Western Carolinas Modernization Project, DEP applied for CPCNs for two natural gas-fired CCs and one natural gas-fired combustion turbine?

A I am.

Q And was -- were all of those capacity additions, the two CCs and the one CT, were those identified in DEP's IRP?

A They have been identified in our IRP.

Q Were they identified in the IRP prior to your filing the application for the CPCNs?

A They were not.

Q Okay. Thank you. Mr. Snider, is it accurate that in this proceeding DEC and DEP propose to reduce the Performance Adjustment Factor from 1.2 to 1.05 for certain QFs?

A Yes, we did.

Q Okay. And is it accurate that -- is it accurate to state that DEC and DEP justify this proposal on the starting reliability of a CT?

A That was -- yes. We justified it on the starting reliability and then we also pointed out that it could be justified under many other utility system metrics.

Q And do you recall that in the 2014 biennial avoided cost proceeding DEC and DEP also proposed to reduce the Performance Adjustment Factor from 1.2 to 1.05?

A I do.

Q And do you recall that that proposal was based or justified on the availability of a CT?

A I do.

CHAIRMAN FINLEY: Ms. Mitchell, is it all right with you if we take a little break for 15 minutes?

MS. MITCHELL: Yes, sir.

CHAIRMAN FINLEY: Fifteen-minute break. We will come back at quarter till 4:00.

(Recess taken from 3:30 p.m. to 3:45 p.m.)

CHAIRMAN FINLEY: Let's have a seat, ladies and gentlemen, and we will go back on the record. Ms. Mitchell.

CONTINUED CROSS EXAMINATION BY MS. MITCHELL:

Q Mr. Snider, just a few more for you. So before we went to break, we were talking about the Performance Adjustment Factor.

A (Snider) Yes.

Q And I asked you if you're aware that the Commission found in 2014 that the Companies' proposal was not appropriate. Do you recall that?

A I do.

Q And do you recall that the Commission said that the availability of a CT is not determinative for purposes of calculating the Performance Adjustment Factor because the fixed cost of the peaking unit and the peaker method employed by the Commission are a proxy for the capacity related portion of the fixed cost of any generating unit?

A Yes. I think I went on in my rebuttal testimony to say that whether you use the peaking unit itself and its reliability or any unit on our system in terms of its -- or the blended average of our system, our on-peak availability is at a level that would justify a PAF of 1.05. So back in 140, when it was just the peaker and the Commission came back and said, well, what about the rest of your system, I think what we tried to show in this docket is that our entire system has an on-peak availability commensurate with a 1.05, and I went in some depth in that in my rebuttal testimony.

Q Mr. Snider, is it true that under the rate schedules offered to QFs by the electric utilities, payment of the avoided capacity rates or what are identified as capacity credits are made only during on-peak hours?

A That is correct.

Q Okay. Mr. Snider, are you aware of -- if the Commission grants the Utilities' proposals related to the reduction in eligibility for the standard offer contract and rates, are you aware of whether Duke has any plans to utilize a performance adjustment -- Performance Adjustment Factor when calculating rates made available to large QFs?

A I don't do those calculations.

Q Okay. Thanks. Mr. Snider, I have several questions related to page 21 of your direct testimony.

A Okay. I'm there.

Q Okay. On lines 18 through 21 you testify that in the context of larger negotiated QFs, DEC and DEP believe it's appropriate to address the cost of ancillary services and other potential integration costs that relate to the specific characteristics of the generator; is that correct?

A Yes.

Q So is it -- is it an accurate characterization of your testimony to say that DEC and DEP intend to account for integration costs and the cost of ancillary services in the rates that are offered to large QFs?

A Again, I testify that I believe it's appropriate to. I do not do those calculations, but I believe that with larger QFs where you have specific information about what that QF looks like on your system as opposed to a generic rate, that's where it would be appropriate to view ancillary costs.

Q Thank you. And has DEC or DEP developed a methodology for calculating those integration costs?

A I have not developed that. I believe Mr. Freeman referred to some of the PNNL studies that have been done, and I think that's one of the differences, as I understand the study, is they were not intended to be real-time operational here -- NERC compliance, what telemetry do I need, what controls do I need to be NERC compliant, as Mr. Holeman, but they were more of a broader study to say if I have to generate with more operating reserves, if I need more flexibility, what does that cost to provide those operating reserves. And while I -- that was not my study, I tend to remember Mr. Freeman's number as being correct, that there was a range of costs to provide those additional operating reserves that ranged on the low penetration end from 2 or $3 a megawatt hour, and on higher penetration those costs were as high as approaching $10 a megawatt hour. That's the extent of my knowledge on ancillaries.

Q Okay. So at this time are you aware of whether DEC and DEP have developed a methodology for calculating the integration costs associated with a specific facility?

A I am not aware.

Q Okay. Mr. Snider, are you aware that in its order issued subsequent to the first phase of the 2014 biennial avoided cost proceeding, the Commission found that the integration of solar resources into the utility's generation mix, depending in part upon their location, may result in cost and/or benefits, many of which may be appropriate for inclusion in a utility's avoided cost -- in a utility's avoided cost calculations; thus, it is appropriate for the cost and benefits attributed to solar integration as such integration becomes more pervasive to be more fully evaluated in detailed integration studies?

A Okay. Subject to check. That's not in front of me, but I believe you're reading that correctly.

Q Okay. Thank you. So has -- I want to ask this question one more time just to make sure I understand the answer. Has Duke -- has Duke developed or performed such detailed integration studies?

MS. FENTRESS: Objection. I do believe that has been asked and answered.

CHAIRMAN FINLEY: Let's see if she can get it so she'll understand what the answer is.

MS. FENTRESS: Okay.

A Again, I'm not responsible for the studies, but I have heard several studies mentioned that have progressed across time that are trying to quantify these impacts.

Q And Mr. Snider, Mr. Ledford asked Ms. Bowman a similar question, and I don't recall whether you answered the question or if she did, so I'm going to ask it again. I'm sure your lawyers will let me know if it's been asked and answered, so I'm going to ask it.

Are you aware that in the Companies' initial filing made back in November in this docket, DEC and DEP requested that the Commission open a new docket to transition North Carolina solar generation landscape towards a smarter, sustainable, and reliable future, and that the Companies identified the following issues that need to be addressed in 2017, one of which was the quantification of solar integration and ancillary service cost and benefits as installed capacity increases?

A Yes. I remember that.

Q Okay. So do you agree, then, that in the initial filing made in this docket, that DEC and DEP contemplated a separate proceeding to address cost and benefits associated with integrating solar?

A I don't -- I did not write the statement. I heard Ms. Bowman answer that she believes that many of these could be contemplated for the general rates filed in the next avoided cost proceeding.

MS. MITCHELL: Okay. I have nothing further, Mr. Snider.

CHAIRMAN FINLEY: Who else has cross? Mr. Stein.

MR. STEIN: Mr. Chairman, Peter Stein for SACE.

CROSS EXAMINATION BY MR. STEIN:

Q Ms. Bowman, I have a couple of questions for you. And a number of the questions that I was going to ask have been covered by counsel for NCSEA, so in the interest of time and efficiency, I will try not to rehash those questions.

CHAIRMAN FINLEY: That's a good idea.

A (Bowman) Thank you.

Q But a couple of just background questions. Again, the Company proposes to reduce the standard -- standard offer contract threshold level to 1 megawatt and to reduce the contract term to 10 years, including a two-year energy update, correct?

A That is correct.

Q And you've described in your testimony a transition under the Companies' proposals in which utility scale solar QFs will have an opportunity to sell their power through bilateral negotiations, correct?

A Are you referring to the competitive solicitation process or are you talking about --

Q Not the competitive solicitation.

A -- the larger --

Q The larger --

A Yes, uh-huh.

Q -- QFs greater than 1 megawatt --

A Yes.

Q -- they can enter into --
A Bilateral negotiations, yes.
Q Okay. And in your testimony you describe the negotiation techniques that the Company has established and developed over time. You mentioned that the Company has negotiated with a number of qualifying facilities, correct?
A I believe that was Mr. Freeman, but yes.
Q Okay. But you do discuss that in your testimony?
A Uh-huh.
Q Okay. And in your rebuttal testimony, and this is on page 21, line 13, you state that each negotiation requires approximately 25 hours of Company time; is that correct?
A I believe as Witness Vitolo states, the Companies require 25 hours or just three business days of staff effort to develop an updated avoided cost calcula--- calculation and to negotiate an uncontested PPA.
Q Okay. And so that is for an uncontested PPA, correct, as you just said?
A Yes.
Q Okay. And if a QF does contest a contract

negotiation and a rate, it may file a complaint with the Commission or petition the Commission for an arbitration; is that correct?

A That is correct.

Q Okay. And would the Company expect the number of hours to address an arbitration or a complaint before the Commission, would that be greater than the 25 hours for an uncontested negotiation?

A I would believe so, but our hope would be to avoid having contested.

Q Okay. Has the Company calculated and included in this proceeding any calculation of contested -- the number of hours or cost to deal with a contested negotiation?

A Not that I'm aware of.

Q Okay. Thank you. So I know we've talked a little bit about the competitive solicitation, and so I won't spend too much time on that, but I just did want to clarify that under the potential competitive solicitation that may be forthcoming, if a solar facility was not successful in obtaining a winning bid in that process, and I should clarify, speaking about a QF larger than 1 megawatt, was not able to participate in the competitive bidding process, the only other option under the

Companies' proposals would be to enter into a bilateral negotiation; is that correct?

A They would still have their PURPA rights to enter into bilateral negotiations for large QFs as exist today.

Q Okay.

A We're just proposing the size threshold would change.

Q Okay. And one more question with respect to competitive solicitation. The Company has said that it would include curtailment rights as envisioned by the Company; is that accurate?

A Yes. We believe that that supports a smarter, more sustainable way to manage solar growth in North Carolina --

Q Okay.

A -- as we've expressed about the operational challenges.

Q Okay. But the Company has not yet determined what it would propose, how often -- let me rephrase the question.

Has the Company established a proposal for how often it would offer a competitive solicitation?

A How often we would offer competitive

solicitation?

Q Yes.

A No. Those details, I mean, we have asked for the Commission to establish that, you know, and we talk about having a solar watt -- you know, megawatt threshold amount, and it would be overseen by an independent third party, but those details, I believe, would be developed in a separate proceeding and we would collaborate with interested stakeholders.

Q Okay. So moving on to a couple of questions about the contract duration under the standard offer which has been proposed at 10 years, it's the Companies' testimony that 1 megawatt projects would have an opportunity to finance projects of that size under 10-year contracts; is that correct?

A Yes.

Q Okay. And over the past few years, the Company has negotiated a number of contracts with QFs since 2014?

A We have.

Q Okay. Do you know how many?

A I don't know that off the top of my head. I'm going to ask Mr. Freeman.

Q That's okay. I have that information.

A Is it in a data response?

Q It is.

A Okay.

MR. STEIN: And I'd like to -- Mr. Chairman, I'd like to circulate this. This was a data response from Public Staff that was not marked confidential. It does include some negotiated price terms. And so in an abundance of caution, I would like to check with counsel and make sure that this is acceptable, but the questioning does not have to do with the prices, but it is included on the document.

MS. FENTRESS: The negotiated price terms would be confidential, yes.

MR. STEIN: Okay.

MS. FENTRESS: Is that your question?

MR. STEIN: I'd like to circulate the document which includes that information. I'm not planning to ask questions about those prices.

MS. FENTRESS: I believe we have signed a confidentiality agreement with the parties sitting at counsel table except for Dominion, and I believe we have also signed one with the Attorney General.

MR. STEIN: Okay.

MS. FENTRESS: So that would be appropriate.

CHAIRMAN FINLEY: I think what he wants to do is ask questions on the exhibit that have something to do without the confidential information. So pass it out and let them look at it. Show it to Duke's attorney there. Can he -- can Mr. Stein ask questions about this exhibit that don't have to do with the price information there?

MS. FENTRESS: Yes, he can. We don't object to that. Thank you.

CHAIRMAN FINLEY: All right. Pass it around to all counsel except Dominion and to the Commission. All right. I'm going to mark this exhibit as SACE Duke Panel Cross Examination Exhibit Number 1, and I'm going to mark it Confidential.

(Whereupon, SACE Confidential Duke Panel Cross Examination Exhibit Number 1 was marked for identification. Because of the proprietary nature of the exhibit, it was filed under seal.)

CHAIRMAN FINLEY: And you'll ask questions about it, but stay clear of the information that you believe to be confidential, please.

MR. STEIN: Thank you.

Q Ms. Bowman, have you had a moment to review this document?

A (Bowman) I've glanced at it.
Q Okay. This document lists the contracts that -- negotiated contracts that the Company has entered into between August of 2012 and January of 2017. Is that -- does that appear to be what's included in this document?
A Yes.
Q Okay. And there are 22 negotiated contracts here, correct? I realize the numbering says 24. For some reason --
A I mean, you have some that are terminated and withdrawn. I'll -- that looks like it's about 22.
Q Okay. And Ms. Bowman, in your testimony and in your summary today you addressed the general principle of economies of scale, is that correct, generally speaking, that larger projects will be less expensive per megawatt than a smaller project?
A Yes.
Q Okay. In this chart under Length of Contract, all 22 contracts are listed at 10 years; is that correct?
A Yes, according to this -- this chart.
Q Okay. Under Capacity Megawatt AC, each QF size is listed there. Do you see those numbers?
A I do.
Q Okay. The sum of those numbers is -- and I

know this is not included in the document, but the sum of those numbers is 827.4. Would you be willing to accept that subject to check? We could certainly use a calculator if needed.

A Yes, subject to check.

Q Okay. And the average megawatt capacity of these projects would then be 37.6 megawatts. Would you accept that subject to check? That's the 827.4 divided by 22.

A Yes. I mean, it appears that the size -- sizes vary quite a bit, but that would be a fair average.

Q Okay. So these are all -- most of these projects and certainly the average are significantly larger than the 1 megawatt threshold that the Company is proposing; is that correct?

A They're all significantly larger. And I believe if you look at the top here, it says these are greater than the 5 megawatts.

Q Okay. So greater than the 5 megawatts.

A Uh-huh.

Q The Company at this time has not negotiated many, if any, contracts below 5 megawatts, correct? Those projects primarily sell their output --

A They take the standard offer.

Q Standard offer. Okay. Thank you. Have the Companies evaluated whether the projects up to 1 megawatt will be able to successfully finance projects with 10-year contract terms and two-year adjustments?

A Well, I am not a financing expert, but we have looked at other jurisdictions across the country and what PURPA implementation standards they have in place, and we have looked at the PURPA rules, and we believe that what we have proposed is -- is a fair and adequate offering for standard contracts.

Q Okay. But has the Company developed any studies or reports specifically in the Companies' service territories whether 1 megawatt QFs would be able to finance with 10-year contracts?

A I don't know that we've conducted a study, per se, but I believe it is our belief and I believe that Public Staff also supports moving to a 10-year term. You know, we are concerned about the cost increases to customers in going for longer terms. Your data is less accurate. And we believe moving to a shorter term is critical for us in this state at this juncture.

MR. STEIN: Okay. Ms. Bowman, I have a document that I'd like to circulate, if I may.

CHAIRMAN FINLEY: Yes.

MR. STEIN: This is not confidential. This is the Companies' responses to a number of NTE solar data requests.

CHAIRMAN FINLEY: I'll mark this exhibit that's being passed out as SACE Duke Panel Cross Examination Exhibit Number 2.

(SACE Duke Panel Cross Examination Exhibit Number 2 was marked for identification.)

Q Ms. Bowman, have you had a chance to review this document for this set of questions?

A I am almost done.

Q Okay.

A Okay.

Q And I will move through these quickly. Request 2-2 on the first page, the question was, "Provide copies of any and all reports, studies, or other documents that DEC or DEP prepared internally with regard to the ability of a solar project to obtain financing in light of their proposal to offer only a ten-year contract with energy rates recalculated every two years." And the response in the first sentence is, "DEC and DEP have no such reports." Is that accurate?

A That is accurate, but I'd like to take a moment to point out that, you know, we did read and listen to the intervenors and with the Public Staff and we proposed a compromise position. In my rebuttal testimony, when it was talking about the 10-year rate and then the two years every -- updating the energy rate, and we made the proposal that we would extend out at that two-year energy rate for the full 10 years to address that concern.

Q So -- and I don't think we need to read through these additional responses, but would it be a fair summary to say that they indicate that the Company has not prepared or commissioned similar reports with outside entities on the same question of financing with financial institutions or solar developers?

A That is correct. And I believe that in the response, you know, our proposed modifications are intended to better meet PURPA's objectives of establishing avoided cost rates that are just and reasonable to our customers, nondiscriminatory to QFs, and in the public interest in light of our current economic and regulatory circumstances related to the amount of solar that we're seeing here in North Carolina.

Q Okay. Thank you. I'll move on. With respect to the Companies' proposal to adjust energy rates every two years, recognizing that the Company has presented an amended proposal in rebuttal testimony, but in your direct testimony you refer to tariffs in other states in the Southeast, correct, that would be similar to North Carolina's avoided cost tariff; is that right? I can direct you to the page. It's on page 49 of your direct testimony.

A So I reference other states, yes, but I don't necessarily see where you say that they are similar. I talk about other states have differing terms, such as Tennessee, Alabama, and Mississippi have all approved minimum standard offer terms of one year.

Q Okay. Thank you. And Ms. Bowman, are you familiar with the tariffs that you've cited on this page?

A Yes. We have a footnote down there where we reference them.

Q Okay. So the Alabama Power, that's rate PAE, correct, that's the purchase of alternative energy?

A Yes, but I don't have a copy of that in front of me at the moment.

Q Okay. I have a copy that I could distribute.

MR. STEIN: Mr. Chairman, I don't need to pass this around, but would it be appropriate to share it with the witness? May I approach?

CHAIRMAN FINLEY: You may.

MS. FENTRESS: Could you share it with counsel as well?

MR. STEIN: Yes.

MS. FENTRESS: Thank you.

Q Ms. Bowman, does this appear to be a copy of the Alabama tariff that you've referenced in your direct testimony?

A It appears to be.

Q Okay. And were you aware that this was a tariff that was available for QFs only up to 100 kilowatts?

A Of not more than 100 kW for customer's own use.

Q Okay. And this is a tariff that is primarily for customers who install renewable generation to use to serve a portion of their load and to sell excess back to the -- back to Alabama Power; is that -- is that correct?

A If you would give me a moment to read what you have handed.

Q Absolutely.

A I believe it says both for own use and desires to sell energy to the Company.

Q Okay. But it -- it would primarily be for residential or commercial users, is that correct, similar to a net metering tariff?

A I don't know if it's similar to a net metering tariff or not. I'd need more time to analyze it.
Q Okay.
A I mean, I would need to look more thoroughly at the whole of -- more closely at Alabama Power to discern that.
Q That's fair. That's fair. I have included on the back page, it's the highlighted section, and that's the excerpt from Alabama Power's website describing its different rates. And I'll just read under Purchase of Alternative Energy. And the heading of the website is Residential Prices and Rates. "Rate PAE applies to customers with distributed generation units such as solar panel array or wind turbine and would like to sell the excess energy back to Alabama Power."
A Okay.
Q Did I read that correctly?
A You did.
Q Okay. So this tariff is not the same as the tariff that the Companies would propose in this proceeding; is that correct? This is -- this is a -- part of the rooftop --
A It --
Q -- distributed generation.

A It appears to be -- it appears to be different, but I am flipping through my rebuttal testimony because I do feel like I said something about Alabama Power in my rebuttal testimony or the state of Alabama. So I did. If you look at my rebuttal testimony on page 38. So I believe it was a recent proceeding. It starts on page 37. And in Ala--- you know, Alabama was talking about -- they said that that was held to be consistent with PURPA and the FERC's prior guidance that a long-term contract in context of PURPA is one year or longer, and I have a footnote citing that, and it was for approval of rate CPE from March 7th of 2017.

Q Okay.

A So perhaps my footnote was perhaps not referencing the right section.

Q But the rebuttal testimony referenced the recent tariff that came out after the direct --

A Yes.

Q -- testimony.

A Yes.

Q Okay. Have you reviewed that -- the Alabama PSC order approving -- approving that rate?

A Only very briefly; not in great detail.

Q Okay. But you do cite to the fact that the

Alabama order states that -- and this is with respect to, just to take a step back, the Windham Solar order, the recent FERC decision that you've referenced in your testimony that -- I believe that was from November of 2016 -- that stated that legally enforceable obligation must be long enough to provide QFs reasonable opportunity to attract financing. You're familiar with that order?

A Yes. I'm familiar with the Windham order. This was in -- this was the Connecticut --

Q That's right.

A -- the Connecticut order, yes, but FERC did not go on to say what was -- what was long enough. And I believe, you know, PURPA says provide for financing, but not at all cost. You have to look in totality in terms of the utility's needs and it has to be just and reasonable rates for customers.

Q And down on page 38 of your rebuttal testimony, the Footnote 47, that is an Alabama order that you've cited. The Alabama order in turn refers to Order 668 -- or excuse me -- 688-A, which was a FERC order implementing the 2005 PURPA amendments; is that correct?

A Yes. And those PURPA amendments were where they exempted utilities from PURPA obligations if there was access to a market and you were size 20 megawatts and above.

Q Okay. So providing a waiver of the mandatory purchase obligation under those conditions?

A Correct.

Q And so Order 688-A was a rulemaking proceeding in -- for 210(m). Okay. In Alabama's order, when you reference it at the top of the page, that a long-term contract in the context of PURPA is one year or longer, are you aware that that statement in -- that the Alabama Public Service Commission referenced was made with respect to Section 210(m) and the obligation -- the waiver of obligation that you just described and not in the context of the legally enforceable obligation regulation?

A I'm not sure. I don't have that order in front of me, but --

Q Okay.

A -- subject to check, but I will say FERC has not gone on record yet indicating a length of term as being financeable.

Q Okay. Thank you. I'll move on. You also reference the Georgia tariff as well. That's on, again, page 49 of your direct testimony. And that is down at Footnote 34, Georgia Power Electric Service Tariff, Solar

Purchase Schedule SP-2; is that correct?

A Yes. I say Georgia requires a maximum five-year fixed long-term contract.

Q That's a five-year term. Okay. Ms. Bowman, were you aware that that particular rate was discontinued last year after the most recent Georgia IRP proceeding?

A No. I was not aware of that. I am aware that Georgia does have some competitive procurement proceedings for solar mandated by their Commission.

MR. STEIN: Okay. Thank you very much. No further questions.

CHAIRMAN FINLEY: Cross?

MS. BOWEN: Mr. Chairman, Southern Alliance for Clean Energy does have questions for Mr. Snider as well. I'm happy to go ahead with those, or if other intervenors would prefer to cross Ms. Bowman first.

CHAIRMAN FINLEY: Go for it. Go for it. You've got a seat at the table. Go for it.

CROSS EXAMINATION BY MS. BOWEN:

Q Good afternoon, Mr. Snider. I'm Lauren Bowen, counsel for Southern Alliance for Clean Energy.

A (Snider) Good afternoon, Ms. Bowen.

Q Mr. Snider, in your testimony you talk about the $2.9 billion QF commitment that Duke currently has in

place; is that right?
A Yes, I do.
Q And that commitment is based on previously litigated and approved avoided cost rates in North Carolina?
A That is correct.
Q And those rates were approved as just and reasonable by this Commission at that time?
A That is correct.
Q The change in value and what you describe as the $1 billion overpayment estimate, that is based on rates proposed in this proceeding as described in your testimony; is that correct?
A That is correct.
Q And so this value would -- or this change would incorporate changes that have been proposed by the Companies in this current proceeding; is that right?
A Yes. And as I point out in my testimony, the largest portion of the change is just a simple drop in commodity prices. So the value today is worth less than it was when commodity prices were higher when these orders were originally approved.
Q Thank you. Mr. Snider, would it also reflect, for example, the proposed change to assigning capacity

value in early years?

A So, yes, we -- it's just looking at the current rate relative to the past rate, so it does reflect that change, and I also note in my rebuttal testimony it still does ascribe capacity value to the QFs, even though ongoing incremental QFs will not be able to provide capacity value to the Company. So there is a capacity component that's being credited when I take that delta.

Q So to summarize and make sure I get this right, QFs will still receive a capacity payment. What has changed in the Companies' proposal is the years in which a capacity value is assigned?

A Yes.

Q And these proposed rates that go into this $1 billion overpayment calculation, those are the rates at issue in this proceeding and have not yet been approved, correct?

A They have not.

Q Mr. Snider, in looking at this delta and the Companies' commitment, is it your position that the Commission erred in its previous avoided cost proceedings and determinations?

A No. I'm not saying that at all. I'm simply saying that at today's market value, it would be no different than if the Company were to buy gas back in 2008 at high levels without the foreknowledge that gas was going to come down 60, 70 percent. It wasn't that they were imprudent; it's just that the commodity markets and the marketplace around them has changed. So I'm just saying that given the change of events, the current value is a billion dollars less than was originally thought it would be in these past two proceedings.

Q Thank you. I think that's a good segue into my next set of questions for you. In your direct testimony you propose that Duke Energy Carolinas and Duke Energy Progress adjust avoided energy rates every two years for a QF that signs up for the standard offer contract, is that correct, in your direct testimony?

A Yes, it is.

Q Okay. And you also support the revised position put forward by Witness Bowman in your rebuttal testimony of providing the option to QFs of locking in that two-year rate over the course of a 10-year period; is that right?

A Yes, I do. And just to be clear, though, when you are referring to the billion-dollar calculation, that was not looking at that two-year rate that we proposed in this. This was taking the long-dated rate in the hydro, the same market conditions that drove the hydro rate, which doesn't have a two-year reset. So it's saying they're out five, 10, 15 years in that hydro rate and said if the QFs that we had previously had were priced at the rates that we have in the hydro rate, that that would be the one billion loss. So I want to make sure that we're not comparing the two-year energy rate to the past order.

Q Okay. That's helpful, Mr. Snider. So the two-year energy rate is not reflected in your estimates of overpayment, but some of the other changes proposed in this proceeding that would apply to non-hydro facilities are included in those calculations?

A Right. We simply took the term of what was remaining, which was 10 to 12, 13, 14 years, and said here is what that maps against the 10-year value as presented in the hydro rate. And it's currently -- for just that 1,600 megawatts without including the 1,100 megawatts that are yet to potentially be established under those LEOs, that's where that calculation came from.

Q Thank you. And then so regarding the two-year avoided energy recommendation, you state that setting the avoided energy price for 10 or 15 years, that that puts risks on ratepayers that natural gas prices will fall and they will have overpaid in the future; is that accurate?

A That is correct.

Q Mr. Snider, doesn't that hedging or that risk, doesn't it work both ways? If you'd like me to explain or --

A Yes. Potentially, the price could go up or down. I think what we've tried to -- and I think what I've explained in my rebuttal testimony, is unlike the Companies' hedging where we're buying consistently across time, if the rate goes down, the QF is under no obligation to sell to the Company at the depressed prices. When the rates are high, they have the right, but not the obligation, to sell to the Companies. And so what Ms. Bowman has testified to, what I've testified to, is while the risk can go either way, there's a systemic bias towards overpaying because you're only seeing QFs enter. When you send a high price signal and you're not seeing QFs enter, you would not see QFs enter it to the same degree as a low price signal. So while the risk goes both ways, the prices could go up or down. That assumes, A, they were set at market prices to start with and, B, that the QF would continue to come in either way, whether market prices moved up or down. So I don't think in the context of this proceeding that there is what I would call a symmetrical risk. I think you have an asymmetric risk that is biased against the customers unless we make some changes.

Q So Mr. Snider, just to circle back, so whether they were at a market price or a set price could have an established avoided cost rate, and particularly for avoided energy there is a possibility that natural gas prices could rise over the course of 10 or 15 years and that -- is that accurate to say that's a possibility?

A Oh, certainly natural gas prices could rise.

Q And -- and --

A It has not been the trend for the last eight years, but at some point they could rise.

Q Thank you. And if so, if that happened, the Company would have locked in a lower price beginning in 2017 than the ratepayers would pay in two or more years if those natural gas prices did rise?

A They would have to rise beyond what was in the filing at the time.

Q Uh-huh.

A So that's all I'm saying, is they were set originally at fundamental prices that were above the market, and so they would have had to first catch up to

-- the market prices would have had to catch up to what was in the fundamentals, and then if they went above that, then the ratepayer could benefit. The opposite has happened.

Q And I believe you describe -- you do describe this possibility in your rebuttal. You say as a result, customers only benefit if realized gas prices over time are consistently above those used in establishing the original QF rates. Does that --

A Correct.

Q Mr. Snider, Duke Energy Carolinas and Duke Energy Progress engage in their own -- in a fuel hedging program; is that accurate?

A Yes, they do.

Q And in your rebuttal testimony you describe recent reactions by the Companies to changes in natural gas prices. Do you recall including that in your rebuttal?

A Please point me to what page and line numbers you're looking at.

Q Sure. It's page 17, lines 3 through 6.

A All right. I'm there.

Q Great. And you state the following reaction by the Company to recent changes in natural gas prices as follows: With this increase in natural gas production, longer range options for purchasing natural gas has become more available and as a result the Companies began requesting quotes for 10-year purchases of natural gas from various brokerage firms; is that correct?

A Yes.

Q And did you describe in your testimony -- elsewhere in your testimony a gas purchase made by Duke Energy Progress on April 5th of this year, 2017?

A Yes, I did.

Q Okay. And that this gas purchase was made for the remainder of 2017 through the year 2026? I can point you to page and line numbers.

A Yes.

Q Okay. So that's correct. And then so this gas purchase was a 10-year gas purchase?

A Approximately. Nine years, eight months.

Q Thank you. Mr. Snider, I'd like to turn now to the Companies' proposals related to avoided capacity value.

A Okay.

Q In your testimony you propose that the calculation of the capacity proportion -- and I'm sorry, let me give you that page number. This is in your direct at page 33, lines 1 to 2.

A Okay. I'm there.

Q Okay. And here's where you propose that, "The calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need," correct?

A I do.

Q Mr. Snider, when the Company makes a decision to add a new capacity unit, such as a combustion turbine or combined cycle unit, that decision is often made years in advance; is that accurate?

A We plan for it in advance, yes.

Q And once that capacity unit is built, there may be a period of reserves that exceed the Companies' minimum reserve targets after the build date?

A Yes. I explain in my rebuttal testimony that that's not by accident. The Company could build small little units that equal reserves in every year, but after careful consideration of the costs and benefits of building larger units that have more economies of scale, like a combined cycle has more economies of scale than a simple cycle, if those benefits outweigh the cost, we build the larger unit and then we will have ample capacity for a number of years until we either grow into or retire units that require us to need additional capacity.

Q And the Companies still receive cost recovery for the entire unit even though the Companies are long on capacity -- they may be long on capacity for a few years after that addition?

A Not despite. We did that because it was the most economic option. Again, we could have very easily built smaller, inefficient, less expensive, maybe on a capital maybe more expensive, but smaller units built right to the reserve margin. The only reason we're allowed to fully recover is that we've demonstrated through the CPCN process that it was more economic to build a larger unit that ended up having some excess capacity than it was to build smaller units. So I think it's not -- we get to recover it despite the fact that we're what's called overbuilt. I'm saying we're economically built, and it was intentional to have excess generation because it was the most economic and prudent decision for our customers.

Q And just to reiterate, you do get cost recovery for those units, correct?

A Yes, pursuant to the -- you know, we go through a very lengthy CPCN process that looks at the costs and benefits, looks at the fact that the units are larger than the one year need for those units, and looks at that in terms of prudence, and once we receive a CPCN, we do receive cost recovery on those.

Q Thank you. And that cost recovery, the Companies get that cost recovery even though the Company doesn't necessarily need all of the capacity in the year that it was built?

A It does need all of the capacity in the year that it was built. That's what I'm saying, is that we could build just to a reserve margin target. That would not be as economic. So we've built above a reserve margin target not ignoring the fact that we could have built smaller units, but despite the fact it was needed in that year as the most economic option, and the fact that we don't have a need until a few years later because you have excess was done very intentionally because you achieved economies of scale in building these larger units.

As a matter of fact, the industry is moving towards even larger units and more efficient units because they give you greater economies of scale and in recognition of the fact that you do have excess generation during certain years, but it's not excess that's just pure excess or a cost to customers; it's excess that was the most economic investment for customers.

Q But you may still have more -- you may have an increased reserve margin for those few years after it's initially built?

A Yes. We would have an increased reserve margin.

Q And Mr. Snider, this proposal to not provide an avoided capacity value in certain years, this has been proposed in prior dockets by the Companies, including the most recent biennial avoided cost docket, correct?

A Yes, it has.

Q And the Commission -- the Commission did not approve that requested change in the last docket, correct?

A I think the Commission stated in the docket that it opens every two years to look at what market -- how the market has evolved, and we propose that in this case we think this is appropriate.

Q Mr. Snider, subject to check because you may not have it in front of you, but the Commission's prior Order in the 2014 docket in discussing this issue said on page 35 of its Order, "The cost of" -- the future capacity -- of "future needed capacity is not changed by the fact that a utility has sufficient capacity in the very near term." Do you recall that or is that subject to check?

A Subject to check.

Q Okay. Thank you. And then that Commission's Order on page 34 also describes --

MS. FENTRESS: Mr. Chairman, we will stipulate that the Sub 140 Order says what it says.

CHAIRMAN FINLEY: We know what the Order says, too.

MS. BOWEN: Thank you, Mr. Chairman.

Q With the Order stipulated, let's move on to the Performance Adjustment Factor proposal in this proceeding by the Companies. Mr. Snider, in your testimony you agree that the rationale -- you agree with the rationale for including a Performance Adjustment Factor in the generic capacity payment to QFs as applied in North Carolina; is that correct?

A Yes.

Q And in your direct testimony in this proceeding you recommend that the Commission should reduce the PAF, Performance Adjustment Factor, from 1.2 to 1.05 for QFs other than hydroelectric facilities with no storage, correct?

A Yes.

Q And you make that recommendation, as you say, to align the multiplier with the reliability of a CT; is that accurate?

A I think I've answered this before and said it's not only the CT, but in rebuttal testimony after reading Public Staff's direct testimony we agree that you can use the reliability of the CT or the reliability of the system as a whole. Either one, when applied appropriately and looked at on their on-peak availability, would be a reasonable adjustment for availability of utility generation, be it a peaker, be it the utility system, be it their baseload generation versus the peak availability of the QF.

Q Thank you, Mr. Snider. And it's been stipulated into the record, but the Commission's Order in the last biennial avoided cost docket found that the availability of a CT is not determinative for purposes of calculating Performance Adjustment Factor. Do you recall this?

A I believe I recall them saying that you should look at the entire system as a whole, and I've -- we've done that since the last proceeding. And when you look at the availability of the entire system as a whole, you will see that we have a 95 percent or greater on-peak availability. So for 36, almost 40,000 megawatts of generation, 5 percent relates to about 2,000 megawatts offline at every time during the peak period. So if I had 2,000 offline, essentially a nuclear unit offline my entire peak period, that would be 5 percent availability. And so we -- on our peak periods we average less than 2,000 megawatts offline if you average it across all our peak hours. So that's how -- another way to look at it. And we've said, per the Commission's Order two years ago, that we'd stipulate that the system is also a way to look at the appropriate Performance Adjustment Factor.

Q Thank you, Mr. Snider, but in the 2014 proceeding, the examination was not on on-peak availability, it was on overall availability, correct, the discussion?

A I think it was on both, and I point out in my testimony that the QF is able -- there's -- only 25 percent of hours or less are on peak in Schedule B. The QF has the ability to be offline the other 75 percent of the time without any penalty to their capacity payment. So they literally can be off 75 percent of the hours of the year and still receive a full capacity payment. And, therefore, to not allow the Utility to have a nuclear fuel outage during off peak and count that towards a PAF would be unfair and discriminate against the Utility generation.

Q Mr. Snider, QFs are available, and you describe this in your testimony, they are available sometimes in off-peak times, correct?

A That is correct, sometimes.

Q Thank you. Mr. Snider, if we look at the broader availability of the Companies' generation assets, so not just focused on on-peak, but broader than that, some of those units are available less than 95 percent of the time; is that correct?

A On the annual basis including refueling outages or -- yes, that could be correct.

Q Okay. And sometimes generating units are available even less than 86 percent of the time; is that accurate?

A Is that a potential on an annual basis? Yes. It would not be my expectation, but, yes, it could happen.

Q Okay.

MS. BOWEN: Mr. Chairman, I have an exhibit that I would like to pass out at this time. Mr.

Chairman, we would mark this as Exhibit --

CHAIRMAN FINLEY: Three (3). I think I've got it.

MS. BOWEN: Okay. Great.

CHAIRMAN FINLEY: We'll mark this exhibit that's being passed out as SACE Duke Panel Cross Examination Exhibit Number 3.

MS. BOWEN: Thank you, Mr. Chairman.

(SACE Duke Panel Cross Examination Exhibit Number 3 was marked for identification.)

Q Mr. Snider, let me know when you've had a moment to look this over and you're ready.

A I've got it. Thank you.

Q Great. Thank you. Does this appear to you to be a 12-month summary of Duke Energy Progress' Power Plant Performance dated from April 2015 to March 2016?

A It does.

Q Mr. Snider, if you'll look at the markings in the top right of the exhibit, these are the original exhibit and page numbers from the docket in which this was filed. If you'll look at that top right corner and look for Schedule 10, page 1 of 7.

A Yes.

Q Thank you. And on that page, Robinson 2 has an equivalent availability during this time frame of 84 percent from April -- and the time frame is April 2015 to March 2016; is that accurate?

A That's what it says on the page, yes.

Q Okay. Thank you.

A Again, I can't say that this is annual availability. So this is not on-peak availability, so it does include nuclear outages which happen on an 18-month rolling basis, generally scheduled during off-peak periods, so we do not schedule our nuclear outages on summer or winter peaks.

Q Thank you. And understanding your position, just bear with me. So if you'll look on page 2 of 7, you'll see the Lee Energy Complex STI had an equivalent availability of 83.01 percent; is that right?

A Yes. I notice you're picking -- out of the entire fleet, you seem to be picking the lowest number, so just draw the Commission's attention to this is equivalent availability on an annual not peak basis on an entire fleet. If you were to average those numbers rather than picking the lowest, you would get something significantly higher than that, but I will stipulate that that one particular unit had an annual availability of 83 percent.

Q Thank you. And Mr. Snider, the Companies still get cost recovery for the units even if they are available less than 86 percent of the time?

A Again, I'd say they get cost recovery for running prudently and being available -- not being available off peak for a nuclear refueling is not an imprudent operation. I would question whether the Commission would deem it prudent if we were 84 percent available during our entire peak period.

Q Mr. Snider, again, you know, understanding your position, I appreciate your patience. So on that same page, still on 2 of 7, Richmond County Combined Cycle 8 had an equivalent availability of 83.97 percent?

A I'm sorry. Which unit?

Q Richmond County CC 8.

A The one below CC 7 that was 96, yes, it was 93, and the following one was 90 --

Q Ninety (90), 92.

A -- 92 --

Q Correct.

A -- and those were annual.

Q Yeah. And to -- for sake of clarity, as you have pointed out, the questions I'm asking you are specifically about units that have been available less than 86 percent of the time average over the year.

A Average over the year.

Q Okay. And then page 3 of 7, Roxboro 3 and 4 steam units had an equivalent availability of 72.71 and 77.73 percent respectively?

A If it will help, I'll stipulate to all the numbers on the page as being correct on all of these pages.

MS. BOWEN: I would accept that if that's fine with counsel --

MS. FENTRESS: Yes.

MS. BOWEN: -- to accept the numbers in this filing. Thank you.

Q Mr. Snider, I do have another exhibit.

MS. BOWEN: And Mr. Chairman, if that's acceptable.

CHAIRMAN FINLEY: Let's mark this exhibit that's being passed out as SACE Duke Panel Cross Examination Exhibit Number 4.

MS. BOWEN: Thank you, Mr. Chairman.

(Whereupon, SACE Duke Panel Cross Examination Exhibit Number 4 was marked for identification.)

Q Mr. Snider, let me know when you've had a moment to look this one over.
A I have.
Q Okay. Mr. Snider, does this appear to you to be DEC's Power Plant Performance Data, a 12-month summary from January 2016 to December, January -- December 2016?
A Yes.
Q Mr. Snider, on page 19 of 40 in the upper right corner -- you're looking at 19 of 40. If you're looking at that page, the Rockingham combustion turbine had an operating availability of 85.08 percent; is that accurate?
A I'm sorry. Let me get to that.
Q Sure. Again, it's page 19 of 40.
A Yes. Once again, 85 relative to the 97 percent availability of Mill Creek, the 96 percent availability of Lincoln, and the 94.96 percent of Lee. So, yes, I see all the numbers on the page and I will stipulate the same to this exhibit as the last.
MS. BOWEN: I'll accept that stipulation, if that's okay with Duke counsel.
MS. FENTRESS: I might have some questions for Mr. Snider on this exhibit, so if we could proceed.
CHAIRMAN FINLEY: All right. You can stipulate

to it, can't you?

MS. FENTRESS: I'll stipulate that the numbers are correct, but I do reserve the right to ask Mr. Snider some questions about it.

CHAIRMAN FINLEY: You may do that.

MS. FENTRESS: I respectfully say that I stipulate the numbers are what they say they are.

A Yes.

MS. BOWEN: Thank you.

Q And, Mr. Snider, the Company -- whether the availabilities are above 90 percent or below 90 percent or below 86 percent, the Company still gets cost recovery for these units?

A The Company gets cost recovery for the prudent operation of units as determined by this Commission.

Q And the Company has not been denied any cost recovery for its plants over this time horizon or the past year; is that accurate?

A I am not the rates expert. I do not -- I can't say. I know we have to keep certain performance standards with our nuclear fleet or we're subject to a potential prudence review if that performance of that nuclear fleet falls below industry acceptable levels.

Q Mr. Snider, I can get the data response if you need it, but in a data request to SACE in this proceeding, the Companies have said that the Companies have not been denied any, and I quote from the data response, "The Companies have not been denied any recovery of capital invested in generating assets since 2011." Subject to check, will you accept that was the Companies' response?

A Yes. My response was in respect to replacement fuel exposure the Company wears, which is not a capital cost; it's a replacement fuel cost that if we did not maintain high operating standards and excellence we would be at risk of. And so I was not referring to capital; I was referring to replacement fuel cost. Again, I'm not the rates expert, but I do know we do keep very high operating standards and are subject to risk of non-recovery if we don't maintain those.

Q I understand. Thank you, Mr. Snider. So let me move on to my next line of questioning. Some of this has been covered. So I'd like to talk for a minute about your proposal to change the winter/summer capacity assignment split in this proceeding.

A Yes.

Q Okay. One of the Companies' proposed changes is to incorporate into its avoided capacity payments a seasonal capacity value allocation of an 80/20 winter/summer seasonal weighting?

A Yes, it is.

Q Okay. And so that's 80 percent winter, 20 percent summer, just to be clear?

A And then the rates I think in Schedule B it's summer and non-summer, just to be clear.

Q Thank you. And this proposal to revise the seasonal capacity split is based in part on the Companies' 2016 resource adequacy studies, correct?

A Yes.

Q If you'd like to, yeah, look at -- no. You're good. And then several of the intervenors in this proceeding -- as you point out in your rebuttal testimony, several intervenors in this current proceeding and also in the Companies' 2016 IRP proceeding have raised questions or concerns about those resource adequacy studies; is that correct?

A Generally, there's been questions. It's a complex topic that people need to take time to digest, but, yes, there's been questions on it.

Q And some of the intervenors with questions have included Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association, and Public

Staff; is that accurate?

A Yes. They've asked questions about our study.

Q Okay. Thank you. And the resource adequacy studies used for the 2016 IRPs, those were based on study year 2019; am I correct?

A That was the base year for the study, yes.

Q Thank you. And in these studies, they also focus on the past five years of data, including 2014 and 2015, correct?

A No. They go much -- they go back much further.

Q One of the purposes, as you describe in your testimony, is to include or incorporate the past five years of data; is that correct?

A Right. They look back 36 years' worth of weather data. The last time we had done a study was 2012 and the two -- I explain in my testimony what's changed dramatically have been not only weather and load response to weather during multiple cold winter events, but probably of more importance is the level of solar we have on the system now that was not envisioned back in 2012 is capable of meeting some of our summer needs, but not capable of meeting our winter needs. And so both of those facts, in combination, caused us to do a new study. It was not that we only use those five years of data, though. We used extensive data going well back beyond that.

Q Thank you. And to point to your direct testimony, page 22, lines 10 through 12, in addition to the solar consideration -- I can give you a moment to get there if you'd like. Direct 22, lines 10 through 12, you say in addition to the solar consideration, one of the purposes of these studies was to, quote, "...account for the significant load response to cold weather that was experienced during the 2014 and 2015 winter periods," correct?

A Yes. That's what it says.

Q Okay. And then you further say in your rebuttal on page 65, rebuttal testimony, line 18, 20 --

MR. BREITSCHWERDT: Would you repeat the page number, please?

MS. BOWEN: Sure. It's rebuttal 65, page 65, line 18 to 20.

Q And the studies include, as you describe it, "...the studies," resource adequacy studies, "included the last five years of weather and load data to develop weather and load relationships that could be applied to all 36 historic weather years," that's 1980 to 2015, "that were included in the study." Did I read that accurately?

A You did.

Q Thank you. And in your rebuttal testimony you provide charts showing historical winter peaks. The focus of those charts is -- and these are, excuse me, on pages 58, 59 of your rebuttal, Figures 12 and 13.

A Okay. I'm there.

Q Okay. And those charts reflect just the last five years of weather data, correct?

A Yes. We were just giving an indication of what our last peaks have been over the last five-year period.

Q Thank you. And then you further distinguish in your rebuttal between the need for winter capacity planning and a designation of the Utility as winter peaking, correct?

A Correct.

Q And in terms of capacity planning, one of the reasons that the Companies are shifting to more winter capacity planning is that solar QF power provides peak shaving during the summer; is that right?

A They provide peak contribution. I don't know if I would say peak shaving. I explain elsewhere in my testimony as we're heading into our summer peak, solar is going away. So while they do have partial contribution, it's pushing our peak further out into the afternoon and it's making our ramp steeper, but it does help us avoid some of those peak hours, at least partially.

Q I believe the way you phrase it in your rebuttal at page 56 is solar resources will -- and that's line 23 -- starting at line 23, solar resources will continue to -- "Despite the fact that solar output is declining going into the afternoon summer peak, solar resources will contribute significantly more to the summer afternoon peak periods than they contribute to winter morning peaks." Did I read that accurately?

A Yes. They don't contribute hardly anything in the morning, so significantly more is correct.

Q In terms of seasonal peaking, according to the Companies' 2016 IRP, Duke Energy Progress now anticipates being a winter peaking utility over the planning horizon; is that right?

A That is correct.

Q However, Duke Energy Carolinas is not expected to be winter peaking until around 2027?

A That is correct. They're very close.

Q As stated in your rebuttal, the Companies are -- and, excuse me, I'll direct you to page and lines. It's page 64, lines 22 to 24. As stated in your rebuttal, "The Companies continue to refine their load forecasting capabilities and evaluate the growth and impact of winter and summer peak demands." Is that accurate?

A That is.

Q Okay. And then also in your rebuttal, this is at page 66, lines 19 through 21, you state that, "The Companies will continue to commission new studies as significant changes occur that may impact study assumptions and results." Is that correct?

A Correct.

Q Thank you.

CHAIRMAN FINLEY: Ms. Bowen, how much more cross do you have there, please?

MS. BOWEN: I would estimate about 10 minutes.

CHAIRMAN FINLEY: All right. Make good use of it, please.

MS. BOWEN: All right.

Q Mr. Snider, earlier today Ms. Mitchell asked Mr. Holeman about the Pacific Northwest laboratory studies. You were present for that?

A I was.

Q And you are familiar with those studies?

A I am generally familiar with those, yes.

Q Thank you.

MS. BOWEN: And, Mr. Chairman, I have one final exhibit to distribute. And this exhibit I've discussed with counsel for Duke. It has some confidential information in it, so we would like to mark it as confidential, but I would like to ask a few questions on the non-confidential portion of it.

CHAIRMAN FINLEY: Very well. We will mark this exhibit that's being passed out as SACE Duke Panel Cross Examination Exhibit Number 5 and we will mark it Confidential and ask that it be so treated in the record.

MS. BOWEN: Thank you, Mr. Chairman.

(Whereupon, SACE Confidential Duke Panel Cross Examination Exhibit Number 5 was marked for identification. Because of the proprietary nature of the exhibit, it was filed under seal.)

Q Mr. Snider, let me know once you've had a chance to look over this.

A I see it.

Q Thank you. Mr. Snider, the Companies commissioned a 2014 integration study by PNNL that was referenced earlier in this proceeding and another study in 2016. Does this exhibit appear to you to be the front page of those studies and an excerpt from them?

A It does.

Q Thank you. And I will note that the 2016 -- August 2016 report is the one that has been marked Confidential, so we won't discuss that, but have stipulated that into the record. For the 2014 excerpt, so this is the second set, do you mind turning to numeral or page number xi at the bottom of the 2014 report?

A I'm there.

Q Okay. And do you see the highlighted text after number 2, Reduce Uncertainty and Variability?

A I see it.

Q Okay. Thank you. Mr. Snider, would you mind please reading the first sentence of that paragraph?

A "Reduce Uncertainty and Variability - Incorporating PV forecast into operation processes and improving forecast accuracy can directly reduce" -- operational (sic) -- "uncertainty."

Q Thank you. And, Mr. Snider, has the Company taken action or is it planning -- or have the Companies, excuse me, taken action or are they planning to take action to follow the recommendation in this report as it relates to improving PV forecasting and enabling regulation services?

A I am not in that group, but I am aware that there is a group of analysts that work very hard to always improve our PV forecast, so I would say it's an ongoing process.

Q And these actions would assist the Companies in managing an increasing amount of QF solar connecting to the system in order to maintain reliability?

A Yeah. I think the question really is to what extent the improved forecast will -- how material will that be. You can't change the fact that, you know, the sun comes up at a certain time and the ramps that Mr. Holeman are seeing now are widely accepted as known. So the question really is just am I really going to experience it today or tomorrow, so do I need those flexibility today or do I need them tomorrow. It's not going to change the fact that you need the flexibility. It's just in real-time day-to-day, minute-to-minute when do I need it. I don't think there is a lot that can be done that's going to say those ramps aren't going to occur or that we're not accurately forecasting those ramps.

Q Mr. Snider, the -- are you familiar with the studies -- the 2014 study also suggests that the

Companies should consider additional energy storage. For example, storage options enabled by these markets represent other potentially -- another potentially effective approach to meet such goals in addition to forecasting. Significant values could be captured through reduction of peaking units, start-ups, and run times using these emerging technologies. Does that represent your understanding of one of the recommendations in the reports?

A Yes.

Q In this report, excuse me. Thank you. And then would you agree that additional storage could help the Companies to manage some of the grid operation and reliability issues the Companies have identified in their testimony in this proceeding?

A I think I just testified earlier that we're adding pump storage capability at our Bad Creek facility that we think will be beneficial in this. In terms of the emerging technologies, the cost from our emerging technologies group, while coming down for storage, still appear prohibitive in terms of wide scale deployment of battery storage outside of pilot programs, so no. You know, I think it's a potential in the future. It's certainly a technology that we're looking at, but we don't see it as being cost effective in the time horizon or practical in the time horizon we're talking about here.

Q But Mr. Snider, you are aware that actual and forecasted battery storage costs have declined in recent years?

A They have declined.

Q Thank you.

MS. BOWEN: I have no further questions, Mr. Chairman.

CHAIRMAN FINLEY: All right. We're going to break for the day. We'll come back at 9:30 in the morning.

(The hearing was adjourned, to be reconvened
on April 19, 2017 at 9:30 a.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 1st day of May, 2017.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150