PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, July 16, 2019

TIME: 9:36 a.m. - 1:01 p.m.

DOCKET NO.: E-100, Sub 158

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

VOLUME: 3

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC, and
DUKE ENERGY PROGRESS, LLC:
Kendrick Fentress, Esq.
Duke Energy Corporation
Associate General Counsel
410 South Wilmington Street
Raleigh, North Carolina 27602

E. Brett Breitschwerdt, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

FOR DOMINION ENERGY NORTH CAROLINA:
Mary Lynne Grigg, Esq.
Nick Dantonio, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Benjamin Smith, Esq.
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY:
Lauren Bowen, Esq.
Senior Attorney
Maia Hutt, Esq.
Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE
and ECOPLEXUS, INC.:
Karen M. Kemerait, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Steven Levitas, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR NORTH CAROLINA SMALL HYDRO GROUP:
Deborah Ross, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR CUBE YADKIN GENERATION:
Ben Snowden, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION:
Robert F. Page, Esq.
Crisp, Page & Currin, LLP
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd.:

FOR NC WARN:

Kristen Wills, Esq.
2812 Hillsborough Road
Durham, North Carolina 27705

Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER AFFECTING THE PUBLIC INTEREST:

Jennifer T. Harrod, Esq.
Special Deputy Attorney General
Teresa L. Townsend, Esq.
Special Deputy Attorney General
Office of the North Carolina Attorney General
114 West Edenton Street
Raleigh, North Carolina 27603

A P P E A R A N C E S Cont'd:

FOR THE USING AND CONSUMING PUBLIC:

Tim R. Dodge, Esq.
Layla Cummings, Esq.
Lucy E. Edmondson, Esq.
Heather D. Fennell, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

TABLE OF CONTENTS

EXAMINATIONS

P R O C E E D I N G S

CHAIR MITCHELL: Good morning. Let's go back on the record. Mr. Levitas, I believe you have the mic.

MR. LEVITAS: Thank you, Madam Chair.

GLEN A. SNIDER, STEVEN B. WHEELER,
and DAVID B. JOHNSON,
having previously been duly sworn, were examined
and testified as follows:

CONTINUED CROSS EXAMINATION BY MR. LEVITAS:

Q. Mr. Snider, et al., I'm a little uncertain exactly about where I left off yesterday, so forgive me if I backtrack a little bit, but one question that we were talking about was the existing PPA contract language and what it means with respect to the ability of the QF to make modifications. And I believe, in your supplemental rebuttal testimony, around page 31, you talk about the -- you talk about facility information that's provided in the negotiated contract; is that correct?

A. (Glen A. Snider.) Are you on page 31 of the supplemental rebuttal?

Q. Page 31, right. And you indicate that -- you indicate that the negotiated contract includes a detailed description of the QF precise location, et cetera, Mr. Johnson?

A. (David B. Johnson.) Yes, that was my testimony.

Q. And that, in fact, is an exhibit to that contract that's labeled "Facility Information"; is it not?

A. Yes, it's Exhibit 4 to the negotiated agreement.

Q. And there's nothing in that contract anywhere that makes any reference or discussion to that facility description expressly being a material term that can't be modified without Duke's approval, is there?

A. I don't think there is for some of the old ones. Now, we have included in some of the new agreements. But again, as I stated yesterday, the agreement -- it's understood that the agreement is for a facility that's built specifically for that PPA; and any changes -- any significant changes to that facility would be considered an alteration of that facility and would need Duke consent.

Q. Yeah, but -- that's my point is, you're seeking to modify the language of the agreement to accomplish that and make it clear, as opposed to that language being in the agreement today, correct?

A. Well, what we're talking about in this proceeding is for the standard PPA providing clarifying language in the terms and conditions.

Q. All right. Let me ask you a question about this issue of the appropriate in-service date to be used for calculating avoided costs that's been the subject of your testimony. And I understand, with respect to the standard offer PPA, that your position is it's been company practice, Commission practice to utilize, I believe, the year immediately following the approval of the avoided costs as the presumed in-service date for projecting out the avoided costs, correct?

A. (Glen A. Snider.) That is correct.

Q. Now, with respect to negotiated contracts, isn't it the case that, when you've negotiated PPAs with QFs, that the avoided cost rates that had been included in those contracts had been based on the actual projected in-service dates? So not the following year of execution or approval of the rate, but the actual expected date that those projects will be placed in service?

A. That is my understandings, yes.

Q. Do you see any reason why that shouldn't continue going forward?

A. At this time, I do not.

Q. Okay. Thank you. Now, I just want to clarify something, Mr. Snider. I asked you yesterday about peer review and the fact that no peer review was done of the Astrape study. I just want to clarify.

I think you might have responded to this, but was it your testimony, or is it your explanation that peer review was not done because it wasn't sufficient time to do it or because you didn't think it was important?

A. Neither. I think my testimony said this was widely reviewed. Your definition of peer review and mine, I think we discussed yesterday, disagrees. I'm not, you know, sure what -- exactly what you mean by peer review, but to the extent this was -- study was done and performed and had extensive review through this process, this entire process started back in November of 2018. We sit here in July, eight months later. The Company and its consultants allowed intervenors and the Public Staff to review this study extensively. It has been compared to other studies by the intervenors; it's been reviewed by Public Staff in light of other similar studies; its results were found reasonable by Public Staff and the Company, and so I think this has probably been reviewed and reviewed by contemporaries more than the average study.

Q. What's your basis for saying that? Do you have some information about what is typical with respect to average review of studies of this sort?

A. Yeah. My experience has been that, as I testified for over 10 years before many commissions, that this study seemed to get more attention than any other study I can remember in recent history.

Q. Are you aware of any industry organizations that provide for formal technical review committees for reports and studies of this sort?

A. I personally am not aware of which ones you are speaking of.

Q. And with respect to the extensive review that you claim occurred, I understand you to say that occurred or was conducted by Duke personnel, by Astrape personnel, and by the Public Staff; is that correct?

A. And by intervenors.

Q. Well, except with the case of the review done by intervenors, as indicated in your testimony yesterday, you don't assign value to that review, and you dismissed it as just them not liking the results, so.

A. Yeah, I think they made some critical mistakes in their review and have a very vested interest in an outcome.

Q. But just to clarify, there was no independent body with no dog in the fight on either side that, with proper qualifications, attempted to review and validate this methodology and its results; isn't that correct?

A. I would not characterize the Public Staff as an unqualified body, so I disagree.

Q. We'll talk later about the qualifications of the staff personnel that was involved in this review. And I also asked you with respect to the involvement of stakeholders.

And I do think you testified, as I recall, in that case, that you simply didn't think there was sufficient time to involve stakeholders in the design and conceptualization of this model before it was conducted; is that correct?

A. No. I think I said -- yeah, I'm not -- I questioned both time and the appropriateness. Again, the stakeholder is -- has a -- utility here is the intermediary. When you say "have no dog in the fight," utility does not really have a dog in this fight. Whether we buy purchase power and pass it through the fuel clause or buy fuel and pass it through the fuel clause, utility is not making more or less money either way. So we don't have a dog in the fight.

And so to bring in a third party who has a very specific dog in the fight, it is their dollars that we are ascribing a cost to. And they're going to come into that collaborative, quote, unquote, process with a very specific objective, which is to minimize that or eliminate that cost because it's coming directly out of their revenue stream.

So I do not believe that that would be an appropriate process, and is not the role of the Company to engage in that type -- when performing a study from an independent perspective that's going to be reviewed by the Public Staff and subject to the discovery and the evidentiary proceeding that we have here today, it would be, to me, not necessarily appropriate to engage in a, quote, unquote, collaborative with the very people who are seeking to minimize or eliminate the charge.

Q. Let me ask you some questions about the timing of when these charges would become effective.

So, as I understand it, the integration charge is going to apply to existing QFs if and when they renew their current PPAs with the Company, correct?

A. I would say, yeah, if they enter into a new PPA.

Q. That's right. And so when do you expect the first such renewal of that sort to occur?

A. I don't know if either of my panels know when the next expiry. We have thousands of contracts. I don't know when the next one expires.

Q. Well, with respect to the standard offer PPAs, they're generally, at this point, 15-year PPAs, these legacy PPAs; and isn't it the case that the vast majority of those PPAs were entered into after, say, 2009?

A. I would agree that, for the vast majority, they would get a 10- to 15-year pass on this charge, yes.

Q. Well -- so that's one way of looking at it. You want to refer to the pass.

My question is, haven't you and your experts acknowledged that the accuracy of this modeling information is likely to improve significantly over time, and with the addition -- with the acquisition of additional data and the performance of additional analysis?

A. I think any model learns from previous endeavors. Part of the reason we're recognizing that the Commission should have this updated every two years is, as those new circumstances evolve, as facts, figures, different approaches come forward, we will bring those forward. I think this is a very good study for this point in time. Am I saying it can't improve over time? I wouldn't say that of any study.

Q. Well, I understand that you think it's a very good study. Experts on this side think it's a highly flawed study.

MR. BREITSCHWERDT: Objection. Is there a question?

MR. LEVITAS: I'm getting to the question. Mr. Snider makes a speech in response to every question I ask, so I've allowed --

CHAIR MITCHELL: Mr. Levitas, please get to your question.

Q. So my question is, given the fact that there are highly respected experts on this side of the table who take serious issue with the study, have significant problems with its methodology and assumption, and the fact that it is not going to apply to any renewing QF contracts for at least the period of time until the next avoided costs proceeding, and very likely the avoided cost proceeding beyond that, what is the rush to ask the Commission to approve the results of this study at this point in time?

A. As we have said, this would apply to new QFs moving forward, solar QFs in particular, that don't demonstrate an ability to alleviate the intermittency they are causing. And that is why we're putting it in at this time, and we're actually not reaching back to other ones as a concession to the QF community to do this in a very measured approach.

I mean, one approach would have been everybody's causing this, everybody should pay for it, let's ask the Commission to have everyone start paying for it immediately. I mean, we're looking to reopen contracts for other reasons. You know, we could have asked for that. We did not.

We tried to give deference to the existing solar QFs and say, now that we have 3,000 megawatts on the system with a $4.5 billion obligation, the Commission ordered, in the Sub 148 order, to specifically identify any costs or benefits that intermittent renewables are producing and then come forward with it; and that's exactly what we did in response to that order.

Q. What efforts did you make to identify benefits that are associated with renewable generation?

A. We have consistently looked for additional benefits. And, you know, I think some of the intervenors have brought up a couple: voided T&D. What we're seeing on a one-off basis, one by one by one, is that there are probably additional costs. It's difficult to ascertain a rate. So it's one thing to say we believe, based on what we're seeing with the QF, that there are T&D costs being imposed that the QF is not paying for, it's another thing to do a study that's substantially supported the way our ancillary service study is to say here's the rate we should charge.

So we're not charging the QF, because we don't have a study to say, oh, the QF is imposing T&D costs, such as the O&M of new facilities that's going to be absorbed by customers. It's hard to quantify that. So we haven't asked for that as a cost. The fact that the T&D that was available on the grid is now being consumed by the existing solar generators which makes placing further firm generation on the grid more expensive is Difficult to quantify.

So we haven't included those costs. The areas that have been brought up as speculative benefits, we have seen example after example of costs. We have yet to define a study that says here is the exact cost it's imposing. So again, we feel that that's a, you know, conservative way to give deference to the QF community and not assign a cost unless we have a defined study that we feel we can quantify those costs.

So we've looked hard at it, we just don't have a systemwide study to define those costs.

Q. Well, did you retain a third-party consultant and ask them whether they could develop a study for the purpose of determining those benefits?

A. Actually, it was -- the benefits you're referring to we see as a cost. We have many examples on a project-by-project basis of where these are costs. So we're not avoiding T&D, we're incurring T&D costs. The other side in this proceeding is claiming those to be benefits. I have yet to, in talking to any of my peers around the country, find an industry or a utility that says the addition of a vast amount of intermittent renewable generation is helping us to have a smaller transmission and distribution budget. I have yet to come up with a single peer that has said that.

I have been to many of my peers who have said, "Boy, we have to figure out how to keep up with the T&D needs of these QFs." So we see an acceleration of T&D costs. I think there is a good effort in the interconnection process to ascribe costs to the QF community that they're incurring, but I don't think we are fully ascribing all costs that they're incurring, and the remainder get, you know, passed on to ratepayers.

So, you know, I would say we've tried hard to look at it. We haven't tried to pass those costs along as a rate deduct in a manner until we have a study that quantifies it.

Q. Well, I understand that's your opinion that you don't think that there are benefits or haven't identified benefits, but I guess your answer to my question is, you did not engage a third-party consultant and ask them to do a study of those benefits to see what they might determine; isn't that correct?

A. We don't believe -- we're -- we'd have a hard time scoping the study, because we're trying to figure out what benefits -- just like the intervenors, I think, didn't hire any third parties that were able to put forward any credible study to say here's a benefit that is being missed. So I'm waiting to review a study that shows a benefit, a concrete avoided cost, but for benefit, that under PURPA, but for the purchase of that QF, there would have been additional benefits to the consuming and using public.

If someone can point those out, we're happy to adopt them. And again, we really don't have a dog. It's what the true indifference price. And right now, the indifference price still gives plenty of deference to the QF community, because we're trying to capture all known and quantifiable costs, but there are certainly additional costs that we have not quantified. We have yet to find a benefit that we haven't quantified.

Q. Are you aware that FERC requires PJM, and perhaps other ISOs, to pay -- to adopt ratemaking to pay QFs for bars that are provided to the system?

A. I am not aware of what they are doing in PJM.

Q. And you were asked yesterday about the recent South Carolina legislation in which the Commission was directed to look at the value of ancillary services, and I believe your answer was you were going to approach that issue the same way you're doing here.

Are you aware that the intention of that language was to consider --

MR. BREITSCHWERDT: Objection. I don't think it's relevant to North Carolina's implementation of PURPA what recent legislation in South Carolina has articulated as how they quantify avoided costs for purposes of that state.

MR. LEVITAS: Well, it imposed -- Madam Chair, that legislation imposes an obligation on the Company, and the question is, how is the Company fulfilling that obligation, and how does that relate to what they do in this state?

MR. BREITSCHWERDT: That's not relevant to the avoided costs in North Carolina, which is prescribed by House Bill 589. I'm sure we will have plenty of time to talk about that in South Carolina.

CHAIR MITCHELL: I will allow the question, but let's just leave it at just one question.

Q. Just one question. My point is just that you answered the question yesterday suggesting that your response would be the same as what you are doing here, which is basically to try to determine the additional ancillary service cost and to potentially develop a charge that would apply to South Carolina generators.

My point to you is, I believe it's the case, is it not, that the intention of that legislation is to require the Company to evaluate ancillary service benefits and potentially credit QFs for those benefits; isn't that right?

A. I think the intent is cost or benefit, get the impact right. I think it's simply what PURPA requires. If the QF can more than offset its -- you know, wants to sell ancillaries back after it's first alleviated the ancillary services cost -- its cost, then maybe there would be a potential. But it first has to alleviate its imposition of ancillaries onto the system before it can be paid for additional ancillary benefits.

Q. Let's talk some about CPRE Tranche 2. We talked about that a little bit yesterday, and I believe the panel has indicated, while there was a little bit of -- I would say the paper filing suggested that was an open question, but I understand it's your position now that you do intend to impose an integration charge

on CPRE Tranche 2 projects; is that correct?
A. I believe we testified we didn't -- it would impact it.
Q. Right. So this goes to a question -- I want to be sure everyone's clear about how this is going to work, because there's been a little bit of confusion and maybe disagreement in the record about this, and the Public Staff has opined on this issue.
The ancillary service charge that Duke is proposing is a discrete charge that would appear in the invoicing to the QF as opposed to a decrement to the avoided cost rate, correct?
A. Yes.
Q. And, in fact, the Public Staff has recommended that Dominion follow the Duke example of using a supplemental charge rather than a decrement to avoided cost, correct?
A. Subject to check, yes.
Q. So in the context of CPRE Tranche 2, the Commission, with your input, will determine the appropriate 20-year avoided cost rate, and that will become the cap for CPRE Tranche 2, correct?
A. Yes.
Q. And as with Tranche 1, the way the bid

evaluation procedure will work is that the market participant will bid a price into CPRE 2; the IA, with the assistance of Duke's Evaluation Committee, if I got the name right, will determine network upgrade costs; those will be combined together; and that will determine whether the combination of bid-plus-integration costs -- or interconnection costs will be below the cap and, therefore, the project will be eligible, correct?

MR. BREITSCHWERDT: Objection, again. I think we went through this yesterday fairly extensively that this has nothing to do with the issues the Commission noticed for hearing in this proceeding. We had a technical conference on CPRE a month ago. Commission issued an order saying that a pre-solicitation process would be commenced August 15th, and the initial RFP would be issued October 15th. We are far beyond the scope of what this proceeding is supposed to address.

MR. LEVITAS: Madam Chair, not only the technical conference but the extensive proceedings leading to the development of CPRE Tranche 2 made no mention and had no discussion of the impact of this charge on CPRE Tranche 2. I've suggested that a major consequence of what you're doing in this proceeding will be the impact of this charge on Tranche 2, and I think it's appropriate to ask questions about that to be sure that the Commission understands how this will work, because it is highly uncertain based on the record to date how this program is -- how this charge is going to affect Tranche 2. And I think that's highly relevant to the decisions that you make about whether or not to approve the charge.

MR. BREITSCHWERDT: And I would just note that the Commission said that the purpose of this proceeding was to evaluate the quantification of the charge and didn't speak to the generalized policy arguments about how it would impact Tranche 2 or other issues that are outside of the general implementation of PURPA. It's very precise in North Carolina law that the Commission and the utility shall follow the methodology prescribed by the Commission in establishing the cost cap for Tranche 2. And Duke plans to adhere to that in August when they would issue the pre-solicitation documents.

MR. LEVITAS: I'll keep my question on

the subject brief.

MR. BREITSCHWERDT: -- what we're here. Thank you.

MR. LEVITAS: I can keep my questions on this subject brief.

CHAIR MITCHELL: All right. Gentlemen, I'll remind you not to speak over one another for purposes of the court reporting.

Mr. Levitas, I will allow the questions for now. Please move efficiently through them.

Q. So I'm just trying to understand the mechanics of how this charge will work in the context of CPRE Tranche 2.

So a bidder is going to have to make an assumption about what the integration -- applicable integration charge would be and design its bid accordingly in order to bid into the process; isn't that how it has to work? They have to account for that charge?

A. Yeah, I think they would definitely account.

Q. And a rational bidder is going to have to assume, will it not, that the potential charge that it faces over the life of a 20-year contract is subject to increases as that charge is potentially increased against the cap, correct?

A. I think, if I was evaluating it and was a bidder, I would say it starts with my base case being the charge as implemented and my tail risk is the cap.

Q. Right. And so, as initial matter, that means that the presence of this charge is going to require that bids be higher than they otherwise would, and the issue is the costs paid under those contracts are fully paid by ratepayers; are they not?

A. The costs paid are fully paid, yeah.

Q. Right. So by moving these alleged integration costs from a ratepayer charge to a supplier charge in the context of CPRE, you're accomplishing nothing to insulate the ratepayers from those charges, are you?

A. Potentially, there were bids that would be right at the avoided costs that might elect not to bid. So yes, we're still ensuring -- and again, House Bill 589 was very clear, is accept bids as long as they come in under the true avoided costs they're creating. So if certain bids don't come in because they're creating costs and they can't cover those costs, then we shouldn't be accepting those bids in the first place.

So no, I think you're still accomplishing the intent of 589 and the intent of PURPA.

Q. Well, I understand that bids may be qualified as a result of having to absorb the integration charge, and that would accomplish the purpose that you suggested. So, to that point, let me ask you this:

Have you done any analysis, looking at the Tranche 1 bids, to see whether those bids would have been viable if they had been required to absorb your currently proposed integration charge?

A. No, I have not.

Q. Do you think that's an important question for this Commission?

A. I do not.

Q. Okay. But getting back to my primary point, even if the charge has the effect of weeding out some costly proposals so that they're no longer eligible, those that do come in under the cap, the point that I was making -- I want to know if you agree -- is that once those integration charges are incorporated into a CPRE bidder's bid, by definition, those costs are going to be paid by ratepayers who are paying the cost of the contract revenues under the CPRE program; isn't that right?

A. Yeah. So long as they come in under --

whatever their bid is -- under the 20-year avoided cost, as approved by this Commission, it's still generating a net benefit for the consumer. And if they need to adjust their bid, that is the way the process should work.

Q. I understand that, but my point is, when they do that, it increases the cost of the power that they're selling within the cap with the result that the ratepayer pays those integration charges just as they do today?

A. I would -- notwithstanding my other comment that says this will allow appropriate bids to come in.

Q. Yes. Okay.

A. They might -- we also talked yesterday about adding innovative technologies to alleviate that.

Q. Right. And I'll talk about that in a moment. So let me -- let me turn to the GSA program for a minute.

MR. BREITSCHWERDT: Objection. We are moving farther and farther afield from the purpose of this proceeding.

MR. LEVITAS: Well, again, Madam Chair, they're seeking to impose a charge that has significant consequences on other programs run by this Commission, and I think it's appropriate for this Commission to understand what the impacts of what they're asking you to do in this proceeding will be for these other programs. And they indicated, in their prior testimony, they haven't even thought about that question, so I'd like to ask a few questions about that.

MR. BREITSCHWERDT: And to that precise point, Mr. Snider indicated yesterday he has no direct knowledge of whether this will be applied or how it would be applied to the GSA program. So I'm struggling with why we're rehashing something that was largely addressed yesterday, continues to be outside the scope of the noticed purpose of this proceeding, and the witness said he didn't have specific knowledge of it.

CHAIR MITCHELL: Mr. Levitas, to the extent the point that you are -- intend to make with your questions related to GSA is different than the point that you have been working on with respect to the CPRE program, I'll allow the questions, but as long as you proceed efficiently through them. But if the point is the same, we have heard the point.

MR. LEVITAS: I will try to condense my questions to make two quick points. One is a process point.

Q. I believe you're aware that the GSE -- GSA proceeding has been in progress for over 18 months; isn't that correct?

A. Yes.

Q. And during that 18-month period, has there been any mention by the Company, anything in the extensive filings that have been made, about the possibility that an integration services charge would be imposed on GSA contracts?

A. I'm not part to that. I have not been a party to those proceedings.

Q. And have you done any analysis of the potential impact of the ability of participating customers to participate in the GSA program if they are required to absorb the proposed integration services charge?

A. No. I have not done any analysis with respect to that, in particular.

Q. I want to go back to a series of -- a few questions about storage.

So it's been extensively covered in testimony that the Company believes that battery storage devices, if properly designed, installed, and operated, can eliminate the integration impacts that the storage charge is designed to address; is that right?

A. Yes.

Q. And yet, at the same time that the Company is asking this Commission to approve this charge, which, as we discussed yesterday, has hundreds of millions of dollars of potential impact on operating facilities, the Company has been unwilling to define, in this proceeding, the exact storage requirements and operating procedures that you deem necessary in order for a customer or supplier to be able to relieve itself of that charge; isn't that right?

A. No, I think we said it's more appropriate that we're addressing the storage protocol as part of 589, and that we would take this into consideration. That if a facility could demonstrate that they materially eliminated their intermittency through storage or other methods, that the Company agrees with the Public Staff that it would not be appropriate to a charge -- a charge for an intermittency they are no longer causing. So that's all we are saying.

And we said we would work in good faith to negotiate those terms and conditions in a negotiated PPA; that we would, you know, work in good faith to have that be included in the storage protocol; and it would not be in a -- again, this proceeding is largely 1 megawatt and under must take what is the 10-year avoided cost rate, that that is something that is more appropriately developed in those storage protocol discussions as well as in negotiations with negotiated PPAs above 1 megawatt, which we're not addressing the rates in this.

Q. The charge that you're seeking to have approved in this proceeding, by your own admission, is not limited in its applicability to 1 megawatt standard offer projects; isn't that correct? You're proposing to apply it in other contexts?

A. Right. But the ability to mitigate it is limited to above 1 megawatt. So under 1 megawatt has a must-take obligation. And if you go under the must-take and you put a battery -- a 500 kW battery with a 900 kW solar facility, we're in a must-take obligation under this. We're not -- we said if that same facility would like to alleviate the charge, we would be happy to negotiate that in a negotiated. But in terms of if they want to just assert their PURPA rights under the file rates, that they would not be able to alleviate themselves of that charge.

Q. But, Mr. Snider, isn't there tremendous asymmetry there? Because you're asking this Commission now, in this proceeding, to approve an extremely substantial charge to be imposed on facilities that you say can be mitigated, but you don't want to address in this proceeding what the parties need to do to mitigate it. Now, if I'm going to try to react to how serious a problem I have here, I want to know, in detail, what I can do to avoid this charge.

Don't you think it's appropriate to deal with all of that at the same time?

A. Yeah. I think, in all fairness, any developer that's putting in a solar facility knows what intermittency is associated with it. They're very familiar with the technical details. They know exactly what they would need to do to eliminate that intermittency. And negotiating the terms and conditions of the storage protocol, I think, would be something that they would be very willing and able to do. And so I think that's just something that is -- we've agreed to work with developers, we've agreed to include it in the storage protocol and, you know, that's where our position is.

Q. Well, in fact, you have left that decision -- I appreciate that you're offering negotiations, but as with so many things, you've left that issue to the Company's reasonable discretion. So, ultimately, you get to decide what those protocols are. If an effected facility doesn't agree with your determination, the only recourse they have is to come to this Commission in timely and expensive litigation to have a dispute with you about that, rather than having this Commission decide those issues on the front end so everybody knows what the rules of the road are.

Now, why do you think that's a preferable approach to this issue?

A. I think we've had extensive discussions in the technical conference that I participated in this Commission a few weeks ago. I think, out of that, there was a desire to go work in a transparent process with intervenors on the storage protocol. I think we're going to try and address this issue as part of that. I think there's nothing to infer that the utility somehow heavy-handedly coming in and imposing this without a willingness to work with parties is just incorrect.

I think, you know, having every detail worked out on the "what would it take to mitigate it" is not -- is not necessary for the Commission to determine whether or not the charges being asked for are reasonable, just, and appropriate for those that do not. For those QF facilities -- again, consistent with 148 and the order that came out of 148, the Commission specifically directed the Companies to identify this cost.

We have done so with a great effort, with, you know, just an incredible amount of discovery that we responded to on this, and we've identified this cost in a way that we feel is just and prudent. And to simply point to the fact that there may be somebody who will offset it but they don't have all the details today so we shouldn't accept this charge just doesn't make sense to me.

Q. Well, isn't it the case that, under your current proposal, you have not even identified a role for the Commission in approving what these operating protocols would be? That's a unilateral decision that you're holding to yourself?

A. Again, outside of this proceeding, we've talked a lot about CPRE, we've talked a lot about all these other programs. They are extensive ongoing proceedings around that. I'm sure this discussion will now, from this point forward, be part of that. So I don't think it's unilateral as you I making it out to be.

Q. Well, I didn't see anything in your testimony that suggested that you have the intention of bringing these protocols back to this Commission for approval; did I miss something on that?

A. I believe the storage protocol that will be ultimately adopted through the CPRE process, to my knowledge, will address concessions for -- or will address the issue of how do you smooth an intermittent facility that has a great deal of intra-hour volatility. And it will allow for smoothing of that facility if that facility wishes to alleviate itself of the integration services charge.

Q. Thank you for that. You mentioned in the context of CPRE. What about storage protocols that would be applicable to facilities outside of CPRE? Do you envision a similar process by which the protocols will ultimately be approved by this Commission?

A. Again, not being the person that is heading up those proceedings for the other programs, my general understanding is we generally point to the protocol and CPRE, and we don't have separate storage protocol because you're under a different program. That's my general understanding. Again, I'm going to -- I'm saying that as the nonexpert in those programs. I have not -- I have not led the effort in those programs.

Q. Let me ask you a question about PURPA facilities.

So if I understand things correctly, upon expiration and potential renewal of a PURPA PPA, that QF would be subject to the integration charge, correct?

A. As we spoke about yesterday, when their contract terminates, if among their many options they, you know, tend to exercise is to renew a PPA, or I would say enter into a new PPA with the utility, if it had wanted to add storage as part of that new contract, then the then prevailing protocol would apply.

Q. And it's also the case, we've discussed this at some length, that -- it goes to my last series of questions -- if that QF is able to appropriately design, install, and operate the storage device, it has potential to be relieved of the obligation to make that -- to pay that charge, correct?

A. If, at that point in time, that was able to do that and the Commission, at that point in time, again, 15 years from now, these rules were to, you know, be in place the way we're proposing them, then yes.

Q. So here's my question and concern:

So if I'm a QF, and I'm at year 13 of a 15-year contract, or let's say you're 10 of 15-year contract, and I'm looking ahead to the renewal term, and I understand the policy -- this policy has been adopted that, if I seek to renew at that point in time, and I don't have storage in place, I'm going to be subject to a charge. So I'm going to make a financial determination, a business determination, and see if it's possible for me to add storage to my system in connection with that new contract term so that I could avoid the charge.

And my question is, under the approach that you have proposed with respect to modification to existing facilities, it's impossible for that operating facility to make the change in order to avoid the charge in its subsequent term without losing the benefit of its current contract price.

Now, what's the basis for that. And doesn't that put the QF in an incredible catch 22?

A. No, I don't think so. I mean, I think we've said there's many alternatives for that QF. If it wanted to maintain its PURPA status and continue to operate as a PURPA QF, we're saying it would need to establish its LEO -- it's second LEO for the new contract within one year of contract expiry. At that time they would have clarity on what the avoided cost rates were that it would be getting paid for its five-year new contract, it would have clarity on what the average integration charge is at that point in time, and it could make a determination whether or not it wanted to add battery storage in that period.

Q. But the question I'm asking about is the lead time that the QF would need to design, finance, build, and install the storage in order to have it in place upon renewal of the new contract. And what I'm asking about is your position that a QF may not do that without relinquishing its current PPA rate.

And so you're creating a serious impediment, are you not, to the ability of QFs to get ahead of the curve and put storage in place in anticipation of the need to avoid this contract charge when it becomes effective?

A. No. I think a year is plenty of time.

Q. What's your basis for saying that?

A. It's already established itself as a merchant generator, right? It's already fully financed. You're talking about an incremental decision to add storage. If it decided to add storage, it could request for that to be studied, it could look at, it could be talking to utilities about what -- you know, what it's planning to do, and then, within one year -- it gives it a year to decide whether or not to pull the trigger. You have an existing facility already interconnected to the grid.

So my assumption is, again, per our conversation yesterday, that's if it wanted to continue to maintain a PURPA must-take under PURPA and not bid into either this utility's or some other utility's general -- you know, they're a merchant generator. They could decide years in advance that, hey, Dominion has an RFP for peaking, they could take that option to say, hey, I want to add a battery to my existing facility and sell it to Dominion. If it wants to maintain its PURPA rights, then, within one year, they would get firm pricing.

There's nothing that stops them. I think we speak in testimony to say, hey, we're thinking about this. We know it's not binding. Here's what we're thinking about. Start talking to the utility about it. We just believe it's not appropriate to lock the consumer into forward prices, three, four years in advance, as argued by intervenors, and let them decide whether they want to or not. Then come again, within a year, have another decision of whether or not they want to lock you into a long-term rate or not, and then decide whether you want to sell as available or under long term when the contract finally expires.

I don't think PURPA ever envisioned the QF to have multiple, multiple puts on the customer three years in advance, one year in advance, real time. As an existing generator, I think what we provided is just and reasonable. It gets plenty of time for the QF to ascertain its options.

Q. I just have a few more questions, Mr. Snider, and kind of a little bit of cleanup on some other matters.

First of all, just circling back to CPRE for a minute, does the fact that CPRE facilities are fully dispatchable affect the appropriateness of accessing an integration charge to those facilities?

A. I think, to the extent they could be fully dispatchable, it could have an impact.

Q. I want to ask you with respect to -- we'll talk to Mr. Wintermantel about this further, but with respect to the cost -- the increased cost that the Company claims it incurs due to intermittency, my understanding is that that's a combination of capital and operating costs; is that correct?

A. I will let Mr. Wintermantel further expand on that.

Q. Okay. I'll come back to that. And this may also -- you, I believe, said yesterday you wanted me to ask Mr. Wintermantel about this, but I just want to be sure I've got your answer to the question.

My question was -- I believe I asked this question, which is whether the Company is subjected by NERC or any other regulatory body to compliance with the LOLE FLEX standard; do you know the answer to that question?

A. Yeah. I think we talked about this yesterday, and what I said is that, irrespective of the standard, the Company is responsible for maintaining realtime operating reliability. And what we've demonstrated extensively in the study is that the -- irrespective of that metric, that, to maintain the same reliability, LOLE FLEX, the -- I guess the Idaho used a spreadsheet-type approach -- you know, the critical thing in all these studies is you have the same reliability before and after, and that you recognize that to maintain that same reliability while also simultaneously introducing more intra-hour volatility requires carrying additional operating reserves. And carrying additional operating reserves has a cost.

So the LOLE FLEX standard is not the -- may not be the NERC standard. That does not -- that's not what we try to imply in the study. It was a manner of looking at what is the reliability both before and after integrating solar onto the grid and ensuring that it's the same either way.

Q. So is it your testimony that, if the Company has chosen or chooses to operate its system to a level of reliability that far exceeds what it's obligated to do in compliance with these national standards and these regulatory bodies, that solar facilities should incur the cost of maintaining that voluntary enhanced level of reliability?

A. No. My testimony is that, whatever the reliability level is, and I think the Company is committed to maintaining a reliable system, certainly it agrees that it needs to comply with all NERC standards, that that reliability level -- and I think Mr. Wintermantel will discuss this in more detail -- but that reliability level be maintained both before and after you add the solar.

And we're not implying, and nor does the LOLE FLEX metric imply that we are somehow drastically overcomplying and being more reliable than required. We -- the study, itself, does not -- does not make that assertion.

Q. I think I have just two more questions. Well, they may be small clusters of questions. The first is, I was asking a minute ago about the costs that contribute to your need to impose these charges and capital versus operating cost. You asked me to talk to Mr. Wintermantel about this, but let me ask you this:

Today, with your ratepayers incurring costs associated with the integration of intermittent facilities, does the Company do everything within its power to mitigate and minimize those costs?

A. Yes. And the Company, within its power, does everything it can to operate and dispatch its system economically. I mean, it's a subject that is of many proceedings, it's how do you operate, just commit and dispatch your system. We do it in the most economic manner possible. Well dispatching in realtime. You have to match load to demand, demand to supply, minute to minute, hour to hour. In doing that, we do it the most cost effective way possible. We just have to carry additional operating reserves when we have more uncertainly. And that's what the study points out. To a large extent -- and again, letting Mr. Wintermantel get into the details -- that is an operating cost.

Q. That was my understanding. And so is it fair to assume that, if you're successful in getting this charge adopted such that these costs will be transferred from ratepayers to solar facilities over time, that you will continue to do everything within your power to mitigate and minimize those costs?

A. Certainly.

Q. And if you are successful in doing that, to the point that the actual costs incurred are lower than the costs that are reflected in the charge that you have collected from the solar facilities, do you have an intention to rebate or true those up so that they will be refunding costs that you didn't actually incur?

A. I think what we're saying is that's the beauty of how we've done this, is we're going to update them every two years. So I don't think there's any retrospective look-back. I think it's saying, you know, they've gone down or up, and now you adjusted on a go-forward basis.

The same way we don't look back on the energy charge that's now, you know, $2-and-a-half billion over what it's worth and ask for the solar community to rebate that $2.2 billion to customers. We're not going to, when we're updating every two years, try and say, well, what were the actuals and let's reconcile. We're saying here was our best estimate. Two years from now we'll update that based on the new situation at that time, and it will be in effect for only two years.

Q. Thank you. You provided a very helpful segue to my last question.

If the Company determines that it's reasonable and prudent to build a natural guess plant and obtains approval from this Commission to do so at a moment in time to meet projected capacity needs in the future, and three, four, five years in, gas prices increase substantially, and it turns out that that gas plant with its 25-, 30-year life was, in fact, a really bad bet, and is going to cost ratepayers substantially more than an alternative, if you had been able to anticipate that alternative at the time you made the decision.

Do you consider making rebates to ratepayers for the excess cost of that facility?

A. I think what the Commission does, on a very regular basis, again, is go through a very detailed certificate of public convenience and necessity process. It's a cost-of-capital based. So we don't get paid for capacity. We get paid for capital invested, if it was invested prudently, which is determined both through an extensive CPCN process and then followed up by a rate case process, which is put into rates.

We periodically then appear before this Commission, and the Commission has cost-based service rate cases, and adjust the equity return that the utility gets over time based on current market situation. All very different than how a QF gets compensated for its investment. It gets a market-based rate or an administratively determined rate. This Commission has no cost-based ratemaking authority over that.

You don't have to show up for a CPCN and demonstrate need. You don't have to make a determination, did I prudently incur those costs; that's all done at market-based or administratively determined based rates, whether it's in the CPRE or whether it's through a standard offer.

So there's very -- and I point this out in testimony. There's very significant differences between how a utility invests capital, how that capital is deemed to be prudent through a CPCN process and the associated rate case that goes with it. That's a very different cost-recovery mechanism than PURPA QFs are allowed, and there are logical trade-offs between the two.

Q. I understand, Mr. Snider, that you take issue with the way that the cost the QFs are allowed to recover are determined relative to the way your costs are established.

A. I don't take issue; I just point out the differences.

Q. Fair enough, that you point out the differences.

But the fact is that, in the way that your cost recovery is determined, if a decision is made that is deemed to be reasonable and prudent at the time that it was made but subsequently turns out, due to change in market conditions, to be significantly more expensive than some alternative that might have been anticipated with perfect insight -- even though it was prudent at the time, no one is saying the wrong decision was made, but the fact is the ratepayers will be paying substantially more for that asset than they would have been if you had had good enough foresight to make a better decision at that moment in time; isn't that correct?

A. I think ratepayers have that potential. They also have the potential to make significant benefit to the ratepayer if it goes in the other direction. So let's take an example of the QF wherever you have a fully depreciated solar plan. Let's say the QF has nothing left on its book, but circumstances at the time determine that your true avoided cost for the utility is pretty significant. If the utility made the same investment on a cost-of-service base, it would only be allowed to put into rate base its non-depreciated book balance. And the fact that avoided costs were seven times higher would all be a benefit to the consumer.

In this case, the QF would get the full avoided cost rate, and the consumer would pay that avoided cost, not the depreciated book balance that the

QF now has on its books. So if your QF that you are saying is going to expire in 15 years is fully paid for, and we have high avoided cost rates, the customer doesn't get that benefit. The customer has to pay full avoided cost rates. It doesn't get the depreciated book balance.

So it can work in both directions. And to selectively pull out the single direction where it may work against the consumer without pointing out that the cost-of-service base ratemaking also gives all the consideration of market moving in their favor to the consumer is not really a fair look at that equation.

So yes, the equation is different, but the consumer also has the potential to benefit very significantly from investments made under a cost-of-service model that they don't have under a QF model.

Q. Well, under a QF model, if markets shift in favor of the consumer, they get the benefit of lower cost energy relative to market rates at the time; do they not?

A. No. They pay the indifference price, even though the QF may have nothing left on its book when it enters into its second contract. And that indifference price doesn't benefit the consumer, it just leaves them indifferent.

MR. LEVITAS: I have nothing further.

CROSS EXAMINATION BY MS. ROSS:

Q. Good morning, gentlemen. My name is Deborah Ross, and I represent the Small Hydro Group in this proceeding. I only have a few questions for you. I think they'll predominantly be for Mr. Snider, but anybody else who has wisdom to share, we'd be happy to hear from you.

Most of my references are going to be to the rebuttal testimony that then would incorporate your preliminary testimony and your supplemental testimony, Mr. Snider, so I'll tell you which page.

A. (Glen A. Snider.) Supplemental rebuttal or rebuttal? Sorry.

Q. Rebuttal. Supplemental rebuttal didn't go to the issues I was dealing with --

A. Got you.

Q. -- so the rebuttal testimony.

So the first question is, in both your direct testimony -- and this was the reference, it was to pages 12 through 14 -- and your rebuttal testimony on page 6, you state that the Company's IRPs have consistently and appropriately assumed that all wholesale purchase contract capacity is removed in the year after the wholesale contract expire, and that QFs are not presumptively assumed to establish a new legally enforceable obligation to deliver capacity and energy to the utilities over a new fixed term in the future; is that correct? Is that what was in your testimony?

A. Yes.

Q. Okay. So -- and you also say that you treat merchant power plant contracts and QF contracts the same for contract renewals, despite the fact that QFs have a federal right to renew under PURPA; you're still treating them the same?

A. Yeah. The -- it's a right but not an obligation, and I think, in this proceeding and in prior proceedings, I tried to point out that the utility has no guarantee. We've had extensive discussion about the QF has lots of rights. None of those guarantee that that energy or capacity will be there after the contract expiry. And PURPA explicitly points out that they have executed a contract over a fixed term.

Q. But the QF does have a federal right to renew their contract should they choose to?

A. At this point in time, they do, assuming that 15 years from now PURPA stands the way -- I mean, they've established a legally enforceable obligation that resulted in a legal purchase power agreement that's entered into for 15 years. So, like, in Mr. Levitas' example, you know, they're just now coming into service 2018. They're going to go through 2033. They have a legal obligation, and we have a legal right to that energy and capacity. If PURPA remains exactly the same a decade and a half from now, they will have that same right to enter into a new contract in 2033.

Q. But, Mr. Snider, we're dealing with something for the next two years. So right now there are two hydroelectric facilities who are going to have expirations of their contracts in 2019.

Do they have a federal PURPA right to renew their contracts?

A. In my understanding, as long as they're still a qualified facility, they have a right to enter into a new contract under the appropriate terms, conditions, and rates consistent with North Carolina implementation of PURPA, yes.

Q. And consistent with the federal law?

A. Right.

Q. Thank you. And so when the Public Staff asked -- and I'm going to hand this you up to you.

MS. ROSS: Madam Chair, may I approach?

CHAIR MITCHELL: You may.

(Pause.)

Q. In the IRP docket, which, of course, is very much related to this docket, because we're basing capacity payments based on the high IRP docket, the Public Staff asked, in Data Request Number 6, Item Number 6-4 in the IRP docket, whether PPAs for QFs are considered renewed after their initial terms, and I've handed you Duke's response to that data request. And Duke replied, "For planning purposes, QF PPAs are expected to either be renewed or replaced in kind. Importantly, however, there's no implicit assumption in the IRP of contract renewals with any given existing QF facility owner"; is that correct?

A. Yes.

Q. Okay. However, your IRPs show that biomass and hydroelectric QFs -- and I'm here for the hydro QFs -- will diminish in the case of DEP from 266 megawatts to zero during winter peak by 2033. And in the case of DEC, from 95 megawatts to 52 megawatts,

again, for winter peak, by 2033.
Is that your recollection of what's in the IRP?
A. Yes, subject to check.
Q. Okay. Thank you. And are you aware that there are three hydroelectric QFs who testified in the public hearing for the IRP and in this proceeding saying that they intended to renew their contracts and they were afraid, because of that IRP, that Duke didn't have an intention to renew their contract?
A. I -- subject to check, yeah, I agree with that.
Q. Thank you. And then, in this docket, in Data Request Number 14, Item 14.4 --
MS. ROSS: And, Madam Chair, may I approach?
CHAIR MITCHELL: You may.
Q. How many hydroelectric QFs have ceased to sell power to Duke, that's both DEC and DEP, since 2010? And in that reply it said that it was only two hydro QFs, one in each of the territories; is that correct?
A. Yes.
Q. Thank you. And are you aware that most of

the small hydroelectric facilities in North Carolina have been operating consistently since the 1980s or earlier and are predominantly in rural counties?

A. That is my understanding.

Q. Thank you very much. Also in your rebuttal testimony, in your testimony from yesterday, you talked about -- and also today, because we've talked about this a lot -- that you talked about all the options for QFs with expiring contracts. And you talked about their ability to participate in RFPs, including the CPRE program, and a variety of different other kinds of ways to participate; is that correct?

A. Yes.

Q. So are you aware that the CPRE program only applies to QFs that are placed in service after the date of the initial competitive procurement?

A. Yes.

Q. And so that's what is in House Bill 589?

A. For these next tranches, yes.

Q. Yes. And so could you explain to me how a small hydro facility would be eligible to participate in the CPRE program?

A. In my understanding, it would not. I was talking to Mr. Levitas about solar facilities.

Q. Okay. So the CPRE program, as it's constructed by the legislature, provides no alternative, other than exercising PURPA rights, to a small hydro QF, correct?

A. It does not stop the QF from bidding into other competitive solicitations, but I agree with your characterization of 589.

Q. And, Mr. Snider, there aren't any other competitive solicitations currently that a small hydro QF would be eligible for; is that correct?

A. At this time, there are not.

Q. Okay. Thank you. My next question is on page 6 of your rebuttal testimony -- so you can take a look at that -- you testified that, in 2018, in the biennial IRPs filed in Docket E-100, Sub 157, that the utility's first respective avoided capacity need arises in 2028 for DEC and 2020 for DEP; is that correct?

A. Correct.

Q. But Duke will be adding new capacity under the CPRE program in the DEC territory; is that correct, between now and 2028?

A. It will be adding new energy, and there might be a tiny bit of capacity.

Q. Okay. And Duke, itself, can bid into the

CPRE program; is that correct?

A. If it has a facility that meets the bid requirements, so yeah, it would need to be consistent with the resources that you just mentioned that are allowed.

Q. Okay. Great. Just a couple more questions. In the IRPs, there is also a discussion about the need for new capacity over the planning horizon.

I believe, on page 8 of both of the IRPs, there is a discussion of additional new customers and demand growth, the potential retirement of some older and less efficient generation, the need for some new resources, and, of course, we've talked about competitive procurement; is that correct?

A. Yeah. I think the other thing driving need is actually the expiration of the contracts, so.

Q. Okay. Your assumed expiration of the contracts?

A. I mean, they expire. It's not an assumption. It's a -- sort of a legal term in the contract, they expire.

Q. But your assumption that they won't be renewed?

A. Yeah. And again, it's -- we explicitly don't count on capacity. We don't have a legal right to. Now, if we enter into a new contract, at the point in which we enter into a new contract, it will go into the IRP. And we treat that very similarly for all resources, whether it's gas, solar, hydro. It's a designated, countable, reliable resource once you have an executed PPA. Those that are undesignated or that are planning resources are simply ones that we plan on but don't have an executed contract. So it's not designated, it's not -- it's avoidable. It is not something that can be counted on.

So we try and -- we've agreed with Public Staff, we're going to, in future IRPs, very clearly delineate when our first need is based on what resources we have today, both physically owned or contracted, and when the first avoidable need is created in the IRP that points to a new resource need for which we do not have either a contract or we own generation to meet that need.

And so, yes, I would just make that delineation. We have resources in the IRP that are both owned and contracted, and then the IRP has planned resources going out into the future that we do not -- have yet not built, that we're not sure if we're going to own, someone else may own. We -- you know, may have a contract for it, but those are undesignated versus a designated resource that we have ownership of or have a contract for.

Q. But, Mr. Snider, right now, we haven't gotten to that lovely point where -- two years from now where we're going to have that statement of need. Right now, in this proceeding, we are having to rely on the IRP that was filed in 2018. And we haven't yet gotten direction from the Commission about how to interpret that IRP consistent with PURPA and consistent with contract renewals for QFs; isn't that correct?

A. I will agree, we haven't got a ruling from this Commission yet on -- in this docket.

Q. And that's a -- that's a significant issue because it will guide how the Companies respond when they do their statement of need in the next avoided cost proceeding because they come so frequently?

A. Yes.

Q. I just have two more questions. So what we were talking about the capacity needs from adding new customers and retirements, and so capacity needs build over time, they're not just fixed at one point in time. They're over the planning horizon; isn't that correct?

A. What is one point in time is when is your first need, right, and that first need then grows over time. So you're adequate in both supply, whether it's owned or contracted, based on what you have today up until a point in time when you become deficient, and then you start, in an IRP, saying here's what my planned resources are under various scenarios and sensitivities to meet that deficient need.

So yes, you have a growing need across time, but you have a specific date at which you have your first undesignated avoidable need.

Q. And just a final question.

And the resources that you have in your stack, whether they're merchant resources or ones that you own, contribute to filling that need up until the point when you need to get something else?

A. Right. Anything that we have owned or contracted contribute to meeting our needs today and into the future up until those owned resources are retired or those existing legal contracts expire. At that point in time, to the extent we have insufficient resources to meet a growing demand, that's what the IRP points out. Here is the point in time in which those existing or contracted resources become insufficient to meet future needs plus a reasonable reserve margin.

MS. ROSS: Thank you. I have no further questions.

CROSS EXAMINATION BY MS. KEMERAIT:

Q. Good morning, gentlemen. My name is Karen Kemerait, and I'm going to be asking questions on behalf of EcoPlexus. And, Mr. Snider, I think, again, most of the questions are going to be directed to you, although if anyone else would like to contribute, because my questions were touched upon by, I think, all members of the panel in your supplemental and supplemental rebuttal testimony.

So I'm going to be focusing my questions on Duke's position about the structure that you have proposed when energy storage is added to an existing facility. So that will be the focus of my questions to the panel.

And, Mr. Snider, to begin with, Duke's position about the structure that you are proposing to the Commission differs from the structure that's been recommended by the Public Staff, NCSEA, EcoPlexus and some of the other intervenors; is that correct?

A. (Glen A. Snider.) It's not my understanding.

Q. Is the structure that Duke is proposing in regard to how PPAs will be provided -- so just to frame, I think, fairly simply what Duke's position is, is that, when energy storage is added to a facility, is it Duke's position that the underlying solar-only facility must enter into a new purchase power agreement with the current avoided cost rates and term, and that the added energy storage also will enter into a new PPA -- or excuse me, a PPA with current avoided cost rates and term; is that correct?

A. Yeah. Let me see if I can restate it. I'm sorry, I may have misinterpreted your first question. When it comes to our position on additional storage being added as a material alteration to an existing contract, it is Duke's position that it's in the best interest of customers, consistent with PURPA and consistent with House Bill 589, that the best way to do that is to negotiate a new contract with that QF provider at the then prevailing avoided cost rates. So that is our position, yes.

Q. For both the added energy storage and the underlying solar-only facility, correct?

A. Yeah. The two are under -- behind one inverter under one meter, so yes.

Q. And under -- with that construct that Duke is proposing, the solar developer would lose its rights to the avoided cost rates in turn with the underlying PPA if it were to, with Duke's position, add energy storage to the facility?

A. At its discretion, it could choose to enter into either a new contracted existing or now current avoided cost rates, or it could retain its rights if it didn't alter its facility, so yes.

Q. And it would retain its rights under the PPA if it decided that it would be -- there would be -- if it decided not to add the energy storage, correct?

A. Yeah. We're in a legally binding purchase power agreement with that facility, that if it doesn't materially alter, we are committed to honoring.

Q. But if the solar developer made the determination that it did want to materially alter a facility by adding energy storage, then what would -- the effect of that would be, if the solar developer had a PPA with, say, Sub 140 or Sub 148 rates, the new rates that would be applicable to the facility would be the current Sub 158 rates; is that correct?

A. Assuming it was standard offer, yes.

Q. And this would be Duke's position that a new PPA would be required with the current avoided cost rates even when energy storage would be added that did not increase the maximum output of the facility; is that correct?

A. I think we've had extensive discussion on that yesterday, that yes, it's going to either increase it -- it's going to either increase or decrease it, and it's going to materially shift when that energy is being delivered.

Q. And you're aware that there is a considerable amount of interest among the solar developers in North Carolina for energy storage and adding energy storage to existing and proposed facilities?

A. That has been purported, yes.

Q. Do you have any information for the Commission about how much energy storage has currently been deployed in North Carolina?

A. I do not have the exact numbers.

Q. Do you have any general information about the number of facilities that --

A. It's been a relatively small number of facilities, as it's a -- you know, a nascent technology coming into existence. I think there has been a lot of discussion around different manners in which storage could be deployed onto the grid. And we have a placeholder for that in the IRP, and there's a few projects that have been -- have been proposed and approved it.

Q. And, Mr. Snider, would you agree that there should not be any unnecessary barriers placed in front of -- or placed that would prevent the appropriate deployment of energy storage?

A. Yes. Unnecessary barriers, yeah, I would agree.

Q. And would you also agree that there would be a disincentive -- a strong disincentive for a solar developer to add energy storage to an existing facility if by doing so the solar developer would lose its rights under its existing PPA?

A. Yes. As I pointed out, the existing PPAs today are generally more than double their current market value. So allowing -- or having to forego that -- what right now is an excessive payment relative to customer value would be a disincentive.

Q. And leaving aside the discussion of whether it is excessive payment, it would be a disincentive?

A. Yeah. I guess our difference is it's not -- I think you used something to the effect of any unnecessary barriers or something to that effect. And what we're saying here, again, is from what's in the best interest of consumers. Is it in the best interest of the using and consuming public to go back in and open up an existing PPA in a manner inconsistent with House Bill 589's intent, or is it better to incent storage through competitive procurement where that storage could add more value for the consumer.

And it's been our position that it's better to do it through competitive procurement. And if existing customers or existing QFs would like to open up their contract to add storage, that they should do so with those same general principles in mind, which would require bringing that into service at now applicable avoided costs.

Q. So, Mr. Snider, I'll ask you a couple more questions about this in a minute, but I did want to touch upon that energy storage can provide benefits to the grid -- to the utilities grid and system -- regardless of whether it is in a project that was bid in the CPRE or a PURPA project; would you agree?

A. They have -- you know, assuming they were operated identically, the question is, then, at what -- if I had two projects, a 5 megawatt battery under CPRE, a 5 megawatt battery under an existing contract, the question then, if they had the same physical characteristics to the grid and to the customer, is just at what cost are customers paying for that identical service.

So yes, I would agree they have the same physical impact on the grid, whether it's a 5 megawatt battery obtained through competitive procurement or a 5 megawatt battery obtained through opening up a PPA and allowing a 5 megawatt battery to be placed into an existing QF. The question then becomes which one is consistent with the intent of 589 and which one has the best and highest benefit for the consumer.

Q. And I'll ask you, in just a couple of minutes, questions about the benefit to the grid for energy storage, whether it is through CPRE -- the physical characteristics through CPRE or through PURPA projects, and I'll get to that in just a minute.

But before I move on, the position of the Public Staff, NCSEA and EcoPlexus is consistent in their supplemental and supplemental rebuttal testimony that the energy storage that is added should be at the current avoided cost rates; is that your understanding?

A. Yes. I think it's testimony that it should be -- the battery, itself, should be at current avoided cost rates.

Q. And no -- no party is advocating in this proceeding that the added energy storage should be at the previous avoided cost rates in the PPA?

A. I think one of the parties raised that perspective and then came in and said, as a negotiated position, they thought that this would be appropriate.

Q. And so the Public Staff and intervenors' position is consistent that the energy storage that was added should be provided a PPA with the current avoided cost rates, but then the underlying solar facility should retain its rights under the current PPA.

That is the Public Staff and the intervenors' position; is that your understanding?

A. That is my understanding.

Q. And the Public Staff has provided information in its supplemental rebuttal testimony that, under that construct in which the added avoided energy storage is provided at current avoided cost rates, that the ratepayers will be fully protected; is that your understanding of the Public Staff's position?

A. I think it's important to say that the public staff said, as an initial matter, that's their position, but they also noted that there is a series of complex, both physical, federal and state legal issues as well as interconnection issues that would need to be worked out. So that conceptually Public Staff says that is their position, but candidly acknowledges that there is a significant number of both physical and legal issues that would need to be overcome to effectuate that position.

Q. Or perhaps to be addressed, that EcoPlexus and the Public Staff discussed that there are additional issues that need to be addressed to accomplish the two separate PPAs; is that a fair way to describe their testimony?

A. I think that's addressed, worked out, overcome.

Q. All right. And I'll move on to that question in a couple of minutes, because EcoPlexus, as you know, has provided some solutions to those technical challenges. But I did want to go back to your testimony about compliance with PURPA for when energy storage is added.

And you testified yesterday and then provided information in your supplemental rebuttal testimony that, if energy storage is added at the current avoided cost rates, that the customers would be indifferent.

That was your testimony yesterday, correct?
A. Correct.
Q. Okay. And so if the customers remained indifferent, then the requirements of PURPA will have been met; is that a fair assessment?
A. Yeah. They would need to be left indifferent, not just -- I mean, PURPA is a broad guideline; 589 is the specific state implementation of that broader guideline under cooperative federalism. So the implementation of it would need to be consistent with the intent of 589, which defines how PURPA is implemented. And so yes, it is my testimony that, as long as it was consistent with the intent of 589, that you would be indifferent.
Q. Okay. And then for the intent of 589, you testified on page 12 of your supplemental rebuttal testimony, is to prevent customers from overpaying for energy storage.
But if the energy storage is added and a PPA is entered into at the current Sub 158 avoided cost rates, then the customers would not be overpaying, they would be indifferent; is that a fair statement?
A. Again, under 589, if it was done for more than five years at full avoided cost, and as I think we

had some testimony on yesterday, that would not be consistent with 589. So again, you have most of these QF facilities are no longer standard offer. It's 1 megawatt and under for standard offer. You have 5 megawatts -- a lot of 5 megawatts, and then you have them as big as 80 megawatts. So now you're talking about adding storage to these contracts and asking consumers to pay for that storage for 10 or 15 years of the remaining PPA at full avoided cost. And that -- I think my testimony is that that is not consistent with 589.

Q. So, Mr. Snider, if energy storage was added to an existing facility and the energy storage entered into a PPA under the current avoided cost rates for a term of five years, then that would be in compliance with 589 and the customers would be indifferent to the source of that power; is that -- is that correct?

A. For the storage, itself, yes. That doesn't alleviate the concerns Mr. Wheeler had earlier about you are now getting a different amount of energy coming out of the residual solar facility than was originally contracted for. So, by definition, you've got to charge the storage with the existing solar.

So the existing solar is now changing what it's obligating itself to by selling you the net output of its facility with the residual going into the battery. And so you've changed the amount that's under the old rate and introduced a new facility within it that's going to take some of that energy to charge the battery. But for the battery, itself, that output at five years would be -- for that particular piece, yes, it would be consistent with 589.

Q. And PURPA?

A. And PURPA.

Q. And I'm going to move on to the questions that I had reserved for the end, my final questions, but since we're talking about these technological challenges, the output from the underlying solar-only facility and the output from the battery could be measured separately by two separate DC batteries; is that correct?

A. I'm sorry, would you restate that? Measured by?

Q. Could be measured separately by two meters.

A. And I'll allow Mr. Wheeler to expand upon this. I think his point was -- our understanding is that it was data loggers that would need to be not utility-grade meters. I think Mr. Wheeler, and I think it's in testimony extensively, points to there's a significant difference of egressing someone else's property trying to use a data logger as opposed to a utility-grade meter on the AC side. Some of the issues that that creates, in terms of the utility's actual control of that device, the M&V, measurement and validation, of that device, the fact that it's intertwined into the customer side, their electrical system, requiring qualified electrician to enter as opposed to a meter tech. There's a host of issues that I think we brought up that, you know, you're not addressing when you just say having a data logger on their side.

Q. So those technological issues that you're mentioning, they are currently being considered by Duke, and Duke is trying to find solutions currently; is that a fair statement? That you're looking for technological solutions to this issue?

A. (Steven B. Wheeler.) I think Duke's concern, overall, is that there's technical limitations on our ability to distinguish the output between a battery storage system in the solar facility. It's all behind the customer's inverter. We only meter at the AC side after it's gone through the inverter and it's delivered to the grid.

We think the simplest solution to resolve this is to renegotiate the entire agreement. If they want to make a material alteration under the facility under current rates and charges, that's what's fair to retail ratepayers who our primary interest is in serving their needs, making certain they're indifferent, as Mr. Snider has said numerous times.

We believe if you install a DC meter or data logger behind the meter, we don't know what that will result, then, on the AC side when it's delivered to the grid. We believe that there are possible workarounds that are not as technically feasible as the AC meter, which we know is 100 percent accurate of what we're actually delivering to the grid and the benefit to ratepayers. There are possible workarounds that we could use using DC meters, or blended rate, or some other approach.

We've agreed, if Commission decides that it needs to be considered, that a working group be set up as Public Staff Witness Metz has recommended, we're not opposed to that if the Commission decides that we need to dig into the details, come up with a different solution than the Company is recommending. What the

Company is recommending is the most technically sound, and that's to install a DC -- an AC meter like we have today to measure the entire output of the facility and to compensate the QF based on that output at current rates.

Q. Mr. Wheeler, I understand that that is, you believe, the simplest solution --

A. And most technically sound, I would add.

Q. Most technically sound at the current time, but technological advances and improvements will continue to occur, would you agree, considering that there is so much interest in energy storage, and that solutions will be sought by solar developers and by electric utilities?

A. And that's the reason we conceded to the Public Staff's decision if the Commission decides against us. That a working group should be formed with all the parties, including your company, and decide what is the best way to try to address, overall, blending some -- a rate from an old rate with a new rate and come up with something which is fair to retail ratepayers, which is what our goal is.

Q. Thank you. And I think that we are in full agreement that a working group and a solution through the working group could be achieved to address this issue.

And then in regard to ANSI standards, you did mention that that was one of the technological -- or one of the concerns about having an appropriate ANSI standard if there were to be two separate meters.

Is Duke currently engaging with EMerge Alliance and Accuenergy to try to develop appropriate ANSI standards for two separate meters?

A. I'm not in the metering area, so I don't know who we're interacting with, as far as looking at ANSI standards, what used to be handled, I thought, by IEEE, who represents the industry to look into what standards are appropriate.

Q. And then are you aware -- are you not aware, then, that Duke has been working with both Accuenergy and EMerge Alliance and preparing draft ANSI standards for these technological -- this new technology for two meters, and that the draft is expected to be prepared sometime in the fall, perhaps even in October?

A. I'm not familiar with that, no.

Q. And then -- thank you, Mr. Wheeler.

Mr. Snider, back to a few questions to you. And this is back to your testimony about House Bill

589. But House Bill 589 does not have any requirements in the legislation that -- let me rephrase the question. Has no requirements that a project outside of CPRE must -- if you must demonstrate customer benefits, if you were complying with the current avoided cost rates.

Is there anything in the House Bill 589 that provides that language to support your position?

A. (Glen A. Snider.) Yeah. As I understand it, it's any new facility -- and this is a new facility being placed into service -- that seeks a long-term rate -- that's above 1 megawatt that seeks a rate of greater than five years for a fixed term shall have the opportunity to do so under competitive procurement or other programs outlined in CPRE. But that -- again that -- suppose it's a 2-megawatt battery, should not be -- a new 2 megawatt battery that's being added to the grid would not -- was never envisioned to be done at a 10 or 15-year avoided cost -- full avoided cost rate, whether it was the old avoided cost or the new avoided cost.

Q. And so for -- if it was a five-year PPA at the current avoided cost rates, there is nothing in 589 that would require the solar developer to demonstrate to Duke or to the Commission about customer benefits, other than compliance with the current avoided cost rates?

A. If it was a new facility, five years or less, no.

Q. Mr. Snider, I want to move on to benefits. You focused on customer benefits, and I think that the parties would disagree that there are no customer benefits to adding storage to a solar-only facility; but let's talk about benefits to the grid for adding storage to a solar facility.

Would one of the benefits be to add more predictable output and to smooth the intermittency of solar facilities?

A. Highly unlikely.

Q. And could you elaborate on why you think that that would be highly unlikely that storage would not have the ability to smooth the intermittency?

A. As I pointed out, I think extensively in testimony, storage, in and of itself, does nothing to smooth intermittency; storage is a time shift. I believe on my rebuttal testimony towards the end, page 65, figure 5 of my rebuttal testimony shows an example of where you could operate storage, and if I was the developer, would operate storage to shift energy from off peak into the premium peak period.

And in shifting that energy, under an existing PPA where there is no financial incentive to smooth, I would not operate a scheme -- smoothing involves quick charge and discharge of that battery. That takes wear and tear on your battery. Why would I charge and discharge my battery while attempting to fill it up in the off peak so that I could move energy to on peak? I would simply charge the battery at a constant rate, as is shown in this example. That rate is low, and to the -- there would be benefit and you -- we've acknowledged the benefit, it's good -- to get higher energy hours, higher cost energy and capacity hours, but you would do it in a manner that left the net output of the facility equally if not more intermittent than the original facility that didn't have the battery. And there is a very clear example of that in Figure 5.

Again, I struggle to see, without the appropriate ancillary service charge and an attempt to alleviate themselves of that charge, how an existing facility would ever have an economic signal to smooth. It's simply going to shift energy. And in this case of -- it's going to have an old set of hours to choose from to charge the battery, because it's charging the battery under old rates. So these are the old Schedule B 140, 136 rates. It's going to take old rates, and it's going to move energy out of the old rates, and it's going to try to minimize the lost revenue from the old rate, and it's going to try and maximize the revenue from the new rate under the proposal by parties to get as much arbitrage between the old B rate and the new Sub 158 rate. And in that arbitrage that the developer will use to maximize its revenues to pay for the battery, it's going to do so in a manner that limits it's O&M cost to that battery and does it in the most efficient way possible.

I don't see how smoothing would be a very likely outcome in an existing contract. In a new contract, if there were to be an integration charge and they could simultaneously try and smooth and shift, they would have that economic incentive, but in the existing contracts, I don't see any smoothing.

Q. So, Mr. Snider, going back to what I -- about the party's position, you were talking about time shift and that time shifts are more profitable periods.

If there are separate meters or a way of measuring the output from the battery, which has been proposed by the Public Staff and by EcoPlexus, then the customers would not be harmed in any way, because the output from the battery would be compensated at the current avoided cost rates; is that correct, assuming you meet those challenges?

A. Notwithstanding you're changing the output from the existing solar facility. The battery, itself, the output from the battery, if it were limited to five years, would not create any detriment.

Q. Thank you. And then -- but I understand your opinion that a solar developer would have no incentive to provide that smoothing, but that is something that a battery is capable of doing. It could ramp up and provide a smoothing for the intermittency. Regardless of your opinion about whether it would be actually performed, but that is what the battery can do?

A. It's technically capable of doing that.

Q. And then another potential benefit to a battery --

CHAIR MITCHELL: Ms. Kemerait, before you ask your next question, how much more do you have for the Duke panel?

MS. KEMERAIT: Probably less than five

minutes.

CHAIR MITCHELL: Okay. Let's go ahead and finish before we take our next break.

MS. KEMERAIT: Okay.

Q. And then another -- Mr. Snider, another benefit to adding energy storage would be that you could -- the time shift where you could provide the output at times when -- peak periods when output or power is most needed; is that correct?

A. Yeah. As I said, it would shift to the premium peak.

Q. And I'll move along very quickly here. But in regard to a peaker plant, for example, a natural gas peaker plant that is the objective of a peaker plant, so energy storage could displace the need for the more expensive peaker plant; is that correct?

A. No. It's an indifference price. It's not a more expensive peaker plant. It's being displaced at the avoided cost rate that reflects the peaker. So it's not displacing a more expensive peaker, it's displacing -- the consumer is paying for that peaker in the form of full avoided cost. Now, if it was done at half of the avoided cost, then it would be displacing a more expensive peaker.

Q. What about dispatchability? Is that -- energy storage can provide dispatchability ability for the utility; is that correct?

A. Partial. In other words, the storage -- again, it's difficult to put 20 or 30 batteries all from different manufacturers and have a utility get in the middle of all that and somehow have full dispatch control. I think storage protocol can give partial dispatchability by sending the right price signal, the right times, the right ramp rates much more so than underlying just solar, itself. So from that perspective, yes, but is it as dispatchable as an asset that's on full automatic generator control that's moving up and down minute to minute at the utility's demand? No.

Q. So, Mr. Snider, this partial dispatch -- as you described, the partial dispatchability of the battery would be valuable to the system?

A. Yes.

Q. And this -- and would you agree that a solar -- with these benefits, that a solar-plus-storage facility would be more valuable to the system than a solar-only facility?

A. Again, I think Mr. Levitas and I went round and round for probably an hour on that yesterday. If you're saying are the costs higher or is the customer -- there is more value and more cost. So it's providing, yes, more premium peak, higher cost energy, but it's at the full indifference price.

So, again, if I'm a consumer, I'm not benefitting any more from paying solar with storage compared to just solar. There's no -- I'm indifferent as a consumer to whether or not you add a battery. Now, the battery in this case is displacing a need for a peaker, but it's being done at the full indifference price.

So the consumer doesn't see additional benefit one way or the other in terms of would my -- would my -- if everything was done perfect in analytics base and it all came out that way, assuming avoided cost rates were perfect, the consumer would be left fully indifferent to whether you added storage or did not add storage. Because if you didn't add storage, we would add a peaker at the exact same -- or the portion of a peaker. The storage does not offset -- four-hour battery does not fully offset a peaker, but it does a lot more than solar standalone. And for that portion that it does offset, you would be offsetting it the full cost I would have billed the peaker for.

So the consumer doesn't see any net bill reduction whether you choose to add storage or not, it simply changes how you provide peak.

Q. Thank you, Mr. Snider. I just have a couple more questions that will be very brief related to the protocol for energy storage. And you testified earlier this morning that the protocol is being discussed in the CPRE context in the docket. And we had a technical conference that I think you were present for.

A. I was there.

Q. Yeah, present for approximately a month ago.

And we had quite a bit of discussion about the energy storage protocol that was included in the PPA for Tranche 1; is that your recollection?

A. I do.

Q. And I think that Duke's statement at the technical conference is that Duke is considering modifications and revisions to the protocol that was in the Tranche 1 PPA and that there -- that there is likely to be a different protocol in the Tranche 2 PPA; is that right?

A. That's a fair assessment.

Q. And the energy storage requirements or protocol have not been provided -- I think Mr. Levitas touched upon this -- in this avoided cost docket; is that correct?

A. They have not.

Q. And at the technical conference, Duke's informed the parties, the market participants, and the Commission that it would provide the revised energy storage protocol to the CPRE market participants so that discussion and collaboration about appropriate requirements could hopefully be agreed to; is that your recollection?

A. That is.

Q. And have those revised energy storage protocol been provided to the market participants yet?

A. I'm not responsible for that. I will let Mr. Johnson answer that.

A. (David B. Johnson.) So we haven't -- we haven't yet submitted the updated protocols, and we're still working on them. But we have had a couple of discussions with developers, and we do intend -- as the Commission ruled in a recent order, we were required to have monthly meetings with stakeholders on CPRE up until we release the Tranche 2 RFP. So our intent is to -- in one of those upcoming meetings, to discuss those updated protocols.

Q. Okay. Thank you very much. That's all the questions I have.

CHAIR MITCHELL: All right. We will take a break and be back at 11:35.

(At this time, a recess was taken from 11:23 a.m. to 11.36 a.m.)

CHAIR MITCHELL: Let's go back on the record, please. And before we resume with the cross-examination of the Duke panel, my intention is to take a recess at 1:00 for lunch. Proceed.

CROSS EXAMINATION BY MR. QUINN:

Q. Good morning. My name is Matthew Quinn. I'm the attorney for NC Warn, and I have tried my best to identify cross examination topics that have not been covered yet, and I cannot promise that I will make an A on that exam, but I will do my best.

So with that in mind, Mr. Snider, I would like to speak with you about a topic that I don't think has gotten as much coverage yet, and that is the Company's natural gas forecasting method.

MR. BREITSCHWERDT: Objection. madam Chair, again, I think the noticed purpose of this proceeding was on a discrete set of issues, and the Commission was very clear in the scheduling order that that topic, while I'm sure Mr. Snider would love to spend a lot of time talking about it, was beyond the scope of what Commission noticed for hearing.

MR. QUINN: On page 23 of Mr. Snider's supplemental testimony, he discussed natural gas forecasting in detail. Also, I think it's extremely important to the Company's support of the stipulation reached with the Public Staff about the avoided cost rates. The Company's acknowledged, themselves, in their joint statement, that one of the primary drivers behind the reduction in the avoided cost rates is the natural gas forecasting. So it's directly pertinent to that.

CHAIR MITCHELL: Given that Mr. Snider has testified to the issue and -- I will allow questions on his testimony, so please stick to matters testified to.

And for purposes of this proceeding going forward, the scheduling order that was entered by the Commission identified discrete issues that -- on which we requested testimony from the parties. The intention was that this proceeding, the evidentiary proceeding, this hearing run as efficiently as possible. Historically, the Commission has allowed open cross. We've been lenient with respect to cross examination.

I will remind you-all, though, that this docket is a bit unusual in that we have identified the topics from which we have -- we want to hear from the parties. So while I will be lenient to a certain extent with your cross examination, please, please, in the interest of efficiency, stick to, to the best of your abilities, the matters on which these gentlemen have provided testimony.

MR. QUINN: Thank you.

Q. (Glen A. Snider.) So, Mr. Snider, as I mentioned a moment ago, I think you probably agree that, according to the Companies, one of the primary drivers behind the reduction in the avoided cost rates is a drop in natural gas prices; is that fair to say?

A. That is certainly a contributing factor.

Q. And when the Commission approved the Companies' avoided cost rates in 2016, natural gas prices were higher than what they are presently; is that also fair?

A. That is fair.

Q. And you probably agree with me if I said that, at this moment, natural gas prices could be accurately described as being very low; is that right?

A. There -- they've been dropping since we've been doing this proceeding for -- since 2012. Consistently orderly I think is what I said in testimony. There's been an orderly decline in the 10-year forward curve for the last six years at least.

Q. And, of course, the lower the natural gas prices, the lower the Companies' avoided cost; is that right?

A. Yes. One component of what benefit a QF provides is that it's allowing the Company to buy less natural gas. So the question is, how much money is the consumer saving, what's the indifference price based on that price of natural gas?

Q. Okay. And so the more that a company's natural gas forecast emphasizes the current natural gas market, like at this moment, the lower the company's avoided cost rates are likely to be; is that fair to say?

A. You know, when you say "prices at this moment," we're not talking about prices at this moment.

We're talking about the 10-year-forward price. So we're going out on a systematic basis and buying gas out 10 years forward. So it's not purchasing gas at today's spot price, which may be significantly below the 10-year-forward price. Just for the clarity, what we're talking about is we're buying 10 years of natural gas out into the future at the then prevailing forward price the same way we're buying QF power at a prevailing forward price for QF power.

But yes, to bring it full circle, the 10-year avoided cost rate has come down, and natural gas prices are one of the drivers. And they are lower today, as I said yesterday, than they were even when we filed these rates back in November.

Q. Okay. So -- and in your answer, you mentioned four prices. And I think what you're getting at there is kind of the difference between a forward prices forecasting model and -- versus a fundamental prices forecasting model; is that a fair and accurate understanding of the component of your answer?

A. No. A forward price is not a forecasting model, it's the market. I mean, you don't forecast a forward, there's -- there are -- as I have said in previous rounds of this, there are multiple forecasts.

Each of the intervenors can bring forward a different entity that forecasts a price. There's a single market. So there's not multiple forward markets. And if you go to buy gas today for 10 years forward, there would be one price for that, and that is the forward price. So you have a forward price and then you have a forecast of what prices might be when you don't have a liquid forward market.

Q. Okay. So just for the sake of our conversation to make sure we're on the same page, my understanding is that the forward prices forecasting method, it represents the future price that parties are willing to contract for now; is that fair to say?

A. It's a price agreed to today for exchange of cash and commodity in the future. So I'm not -- just to be clear, a forward, you don't pay for it in advance; you agree on a price and then that price settles in the future. But yes, it's a market price established today for a future period.

Q. And so, then, conversely, the fundamentals forecast looks at a longer-term trend in the natural gas market; is that fair to say? It looks more market dynamic supply and demand on a national and international scale?

A. No. I would say they both -- I mean, if you're transacting, if you're in that market, a forward market participant, it's all suppliers, all consumers are coming together and saying that encompasses all of the markets' beliefs about supply and demand at a single price.

A forecast is dependent on who you get to provide the forecast, and they have different macroeconomic views. And like I said, there will be multiple forecasts.

So yes, there are more forecasts than there are forwards, and they all have varying views of what those supply and demand factors are, except for a forward price where there is but one view, and that's the market's view.

Q. Okay. In light of that, isn't it true that the more reliance on a forward prices forecasting model that the Company uses, the more that the Company's natural gas forecast will reflect current low natural gas prices?

A. Again, it depends on -- most of the fundamental forecasts today are above. Because of the trend, we've had extensive testimony in this case and prior cases that the fundamental forecasts have struggled to keep up with the market, and they're usually done on a year to two-year lag compared to a market that's transacting in realtime.

So I would say that no, the gas price that we've transacted at -- as I pointed out, we just did another transaction last week where we bought 10 years of forward gas at a single transaction price that is today lower than some historic fundamental forecasts. There may be a point in time where someone forecasts prices to be lower than the market.

And, in this case, given the trend that I just spoke about since 2012 of constant steady decline, if we went back and looked at the transcripts from 2012, '14, '16, and '18, every time we said the market can't go any lower and that the fundamental forecasts are more correct, and over the last six to eight years, all that's happened is the fundamental forecasts continued to decline in response to what's happening in the marketplace.

So the marketplace, in my opinion, is by far and away the best not estimate, but the -- more importantly, is the price at which transactions are taking place. So we are entering into physical transactions, buying gas at a certain price level, and our clear interpretation of PURPA is we should not be required to buy the same power at a higher level.

Q. Okay. Well, then, let's compare your belief that the forward-pricing model is preferable. Let's compare that belief to, I guess, some of your colleagues or other utilities.

Would you agree with me, Mr. Snider, that the Companies use -- in this avoided costs docket, the Companies use a natural gas forecasting model that uses 10 years of forward prices before transitioning to a fundamentals forecast; is that an accurate summation?

A. That has been the case in the last four or five IRPs and the last several avoided cost filings, at least what we've presented to this Commission, yes.

Q. Okay. So relevant to the other utilities --

MR. BREITSCHWERDT: Objection. I'm not seeing where Mr. Snider's supplemental testimony or any testimony filed in this portion of the proceedings speaks to how other utilities are analyzing their future procurement of natural gas or how they're making purchases out in the future. This is something certainly addressed extensively in the comment proceeding that preceded the evidentiary proceeding, but I think we're getting far afield from them.

MR. QUINN: One of the topics for this evidentiary hearing is the Companies' support of the stipulation for the Public Staff about avoided cost rates. The primary -- as Mr. Snider, himself, acknowledged, the primary driver behind the reduction in avoided cost rates is natural gas prices. So, to my mind, the topic that we're discussing right now is probably the most important component of this evidentiary proceeding.

CHAIR MITCHELL: Do your best to stick to the issues on which these gentlemen have provided testimony. I ask that you move through these questions efficiently.

MR. QUINN: Yes, ma'am. I will do so.

Q. Mr. Snider, is it fair to say that the use of 10 years forward prices forecasting before switching to fundamentals, that's a fairly unique way to project -- to project natural gas prices among utilities?

A. Again, it's not projecting, it's actually procuring. So we're not projecting, we're actually buying. And that is the market price of gas, which is the market price that should be used for power. They need to be equivalent. We said that repeatedly.

It isn't -- when we say it's unique in that other utilities, it is ironic that what has precipitated the use of 10 years of forward is the fact that we now find ourself in a position where by not using actual market, we end up with thousands of megawatts that are currently excessively above the true value being created for the very reason that we -- that caused us to go to 10 years.

So we went to 10 years because we ended up -- we're buying power out 10 years, 15 years under the old rates, at rates that were significantly above the market -- the actual market for natural gas. So I would purport that, if there were any other utilities that found themselves in a $4.5 billion obligation to a long-dated QF community, they would very well be buying gas out a commensurate tenner to ensure that they were getting the true indifference price of a forward transaction for power with a forward transaction for natural gas.

The very nature by which this came about was the obligation to go out 10 and 15 years and lock in two forward power positions. As a result of that, back in 2012 and 2014, it was questioned whether there was an equivalent market that was liquid. There was a lot of discussion around whether that market was liquid and transparent. We started getting quotes for that. It was argued that maybe the quotes were not transactable. And starting a few years back, we started transacting.

And we've demonstrated that not only we but other utilities are also buying out 10 years, that we're not alone in doing this, and it's really just and prudent, on behalf of customers, to ensure that, if you're going to make forward natural gas transaction or power transactions to QFs, that they should be commensurate with and equal to what you could have, the but for principle, indifference principle, you could make that same forward transaction for natural gas. And we -- I think, as Mr. Breitschwerdt has mentioned, we've, you know, commented on that extensively in this proceeding and in prior proceedings.

Q. I appreciate your defense of the Company's natural gas forecasting model, and suffice it to say that multiple intervenors disagree with it, but that wasn't exactly my question.

What my question was is, isn't the Company's natural gas forecasting model unique relevant to other utilities? I guess what I mean by that is, Mr. Snider, can you identify another utility in the entire country which uses a natural gas forecasting model with a 10-year forward-pricing component?

A. Two issues there. One is I've said repeatedly it's not a forecasting model. There's a fundamental difference between a forecasting model and a liquid forward market. So no, no one using that forecasting model, because it's not a forecasting model, it's a market.

Second, reliance on forwards, as we've demonstrated to and we filed as a confidential response in one of our interrogatories, is yes, there is another utility in the southeast that is also buying gas at significant quantities out 10 years, and that was provided as a confidential response to a data request.

So yes, I can; and no, it's not a price forecasting model.

Q. Okay. So I don't want to get into the confidential issues, but there is one other utility that you've been able to identify; is that correct?

A. Yes.

Q. Any other than just one?

A. Well, as I point out, no other utility also that am I aware of that is buying $4.5 billion worth of QF must-take at administratively determined rates that are reliant upon gas prices. So North Carolina is uniquely situated in the very position that precipitated us going out and buying gas that far into the future to ensure that we had this indifference principle in place at the right level.

So it's a circular reference here to say North Carolina uniquely went out and procured 3,000 megawatts plus of solar at 10- to 15-year contracts, which then required, from a prudence perspective, to make sure that that was being done at the prevailing market that consumers would be indifferent to if the Company simply went out and bought the natural gas.

So the very nature of the North Carolina QF process precipitated this, and now they're using the argument that we're unique in buying natural gas that far forward as a reason not to do it. Well, you know, by that respect, just tell us what natural gas forecast we should use so that you can get a high enough rate; that's not the way this process should work.

Q. Mr. Snider, you mentioned the unique situation of North Carolina. So that raises me to ask the following question:

You are, of course, aware that Dominion is a utility in North Carolina; is that correct? A public

utility in North Carolina?
A. Yes. They have a small portion of their service territory in North Carolina.
Q. And are you familiar at all with Dominion's filings in this avoided cost docket?
A. Roughly.
Q. Okay. And are you aware of the natural gas methodology used by Dominion in this case? That they use forward prices for 18 months and then switch to fundamentals; is that fair to say?
A. Subject to check, I would agree with it.
Q. So subject to check, if that is indeed a correct statement of Dominion's position, then I'm sure you would also agree that Dominion's method, there's about an eight-and-a-half-year difference in the use of forward pricing between Dominion and Duke; is that correct?
A. I think the difference between one and a half and ten is eight and a half, yes.
Q. Mr. Snider, are you -- let me ask that question again.
Mr. Snider, you're an employee of Duke Energy Company; is that correct?
A. Yes.

Q. Okay. And Duke Energy Company, of course, is the parent company for several subsidiaries, right?

A. My responsibilities lie with Duke Energy Progress and Duke Energy Carolinas.

Q. Fair enough. Then are you familiar at all with the natural gas of subsidiaries Duke Energy Florida, or Duke Energy Kentucky, or Duke Energy --

MR. BREITSCHWERDT: Objection. I'm going to raise the same objection I raised previously; we are now far outside the scope of what Mr. Snider's supplemental testimony speaks to in this proceeding. We're squarely within the comments that were filed by the Public Staff, by Duke, by numerous other parties that the Commission specifically said they did not want to hear testimony on. These were issues that had been considered and decided before, and Mr. Snider didn't prepare -- while he seems fairly well prepared to articulate his views on this, we didn't go back over what we addressed in the comment based in this proceeding related to what Duke Energy Florida does or other utilities. It just seems like, in the interest of expediency and efficiency, we're far, far outside the purpose of this proceeding.

MR. QUINN: And I disagree with that vehemently. As I said a moment ago, one of the, if not the most important, issue in this evidentiary hearing is the stipulation between Duke and the Public Staff and the Companies' avoided cost rates.

MR. DODGE: Madam Chair, if I could interrupt there. I just want to point out, the Public Staff entered into two stipulations with Duke. One related to rate design, which dealt with the schedule, the hours and the months during which on and off peak, the rates would be assigned; and then also with regard to this whole integration services charge. But we are certainly not in agreement with all issues including gas price forecast with the utility.

MR. QUINN: And that's absolutely understood. But the stipulation between the Public Staff and Duke and -- goes to the very heart of what the avoided cost rates are going to be.

CHAIR MITCHELL: All right. Mr. Quinn, I have -- we have given you some time to ask your questions on the natural gas forecast construction methodologies that the Company has used or not used. I have asked you to stick to the matters that have been testified to by these gentleman in this proceeding, and, you know, we are now 15 minutes into your cross-examination. So I'm going to give you two more minutes to make your point, and then move on to the next topic, please.

MR. QUINN: I will -- in deference to that, I will move on to the next topic now, and I appreciate that.

Q. So, in light of that, I'd like to shift our conversation away from the natural gas issue and toward the standard terms and conditions. So, Mr. Johnson, I expect that a lot of my subsequent questions are going to be directed at you, but there's a lot of overlap here between yourself and Mr. Snider. So, you know, by all means, you know, both gentlemen, please interject where you think is appropriate.

Mr. Johnson, is it fair to say that, as we move into the forward future, that battery storage is going to play a greater and greater role in the utility market?

A. (David B. Johnson.) That seems to be the way it's gone, but it's still to be decided.

Q. Are you familiar with the Companies' IRP filings for 2018?

A. That's not my area of expertise, so just generally familiar.

Q. Okay. Then my question is probably -- general familiarity is probably going to be sufficient. I guess what I wanted to just -- I just wanted to get on the record is that, would you acknowledge that the companies have expressed, in their 2018 IRP filings, the objective of adding about $500 million in battery technology in the Carolinas over the next 15 years?

A. (Glen A. Snider.) Roughly the amount of investment in a number of batteries that we had put placeholders in the IRP for.

Q. And so, presumably, the Companies are making this $500 million investment, or something in that ballpark, because they anticipate that batteries are going to play an important part in the utility market as we move forward in the future; is that fair to say?

A. I would say it's a growing part for sure. I think the big debate with any nascent technology is just how quickly and how fast it grows. So we have a placeholder for some amount of storage, could be on the transmission system, could be on the distribution, could be paired with solar, but there's a placeholder recognizing growth in that.

It's still a nascent technology. We're talking -- I think our placeholders are a little over 100 megawatts in the two utilities' IRPs. I apologize, I don't have my IRP with me right now. That's relative to a -- you know, a combined system of, you know, nearly 40,000 megawatts. So yes, it is not insignificant. It is a growing -- but it is still a nascent technology that is coming into utility scale.

Q. Would you acknowledge that the cost of battery storage has been on the decline for several years?

A. Certainly.

Q. And would you also agree that the cost of battery storage is projected to continue to decrease as we move forward into the future?

A. We have those projections in our IRP.

Q. And so, therefore, I think we can probably agree that investment and battery storage is a prudent investment that the Companies are -- have forecasted that they're going to make; is that fair to say?

A. Actually, they're placeholders right now. You know, I think what we say is, you know, battery storage has the potential, if costs come down significantly, to be a prudent investment. At today's prices, a standalone battery, you know, if I were to put one in tomorrow, is not cost-effective.

But given declines, given the potential to solve potential T&D and G issues, you know, once we work through stack value, you know, it has potential. It has potential to be prudent, but it's dependent upon, as Mr. Johnson said, a lot of factors.

Q. I've read several places in this docket that one of the Company's chief concerns about solar generation is that it's intermittent and non-dispatchable; is that fair to say?

A. I don't know if it's a concern, it's just a recognized difference. I mean, it still provides energy value. We're not saying it doesn't provide value. It's just a recognized difference that does impose certain costs on the system that we have to account for.

Q. Okay. Fair enough. Would you acknowledge that adding battery storage to a solar facility would allow a shift in the production of electricity to more valuable peak times?

A. Yes. To higher -- we had this discussion at length, to periods where there is a higher cost to provide that same energy.

Q. And we have had this discussion, so I've cut a lot of questions about this, I promise, but my colleague with EcoPlexus did a good job on this subject, and there's just one -- I think one follow-up question or cluster of follow-up questions that I wanted to ask just to try to make sure I understood your testimony.

Would you acknowledge that battery storage technology creates the -- at least the possibility of helping the Company's -- of addressing the Company's concerns about solar generation being intermittent and non-dispatchable?

A. It has the potential to change the time in which energy is being delivered, for sure. As I said, we still have a lot -- a long way to go before it can be fully dispatchable; but it is certainly -- as I think I explained earlier, it's partially dispatchable. It's certainly less intermittent than pure solar standalone.

Q. And you would also agree, I'm sure, that the -- it's important for the Companies to incentivize the use of battery storage?

A. Yeah. I think I testified extensively

yesterday that this very rate design that we stipulated to with Public Staff sends a very significant price signal for incremental battery storage.
Q. Just so the record is clear, is that a yes to my question, it's important to incentivize the use of battery storage?
A. If done at the proper avoided costs, absolutely.
Q. Now, of course, the Company's position in this docket is that, if a QF were to install storage, then it's a material alteration and require a new PPA at new avoided cost rates; is that fair to say?
A. Yes.
Q. And those new avoided cost rates would be higher avoided cost rates, correct?
A. During the --
Q. I'm sorry, wait a minute, lower avoided cost rates.
A. It depends by price period. So during the premium peak winter hours, you have certain price periods where the new rates are higher in that particular period than the old rates. The average rate for around-the-clock, you know, QF that was 100 percent available would go down. But any given price period,

it depends on looking at the comparison of the price period.

Q. So switching topics just a little bit, Mr. Snider, you are aware that an electrical energy storage device is used to store electricity rather than to generate additional electricity; is that fair to say?

A. Yes, depending upon its application. It has the ability to do both when paired with storage.

Q. I guess you're also probably aware that the process of storing and then discharging electricity from an electrical storage device involves an inherent efficiency loss; is that fair to say?

A. Yes.

Q. Okay. And are you also aware that, in the wintertime, solar generators produce less power than in the summer, and often produce less than their maximum output rating at their peak winter daily production periods?

A. Yes.

Q. So are you aware, then, that solar generator -- that a solar generator that stores and then discharges part of its production on winter days using a battery may, in fact, produce less overall energy output on those days, not more; is that fair to say?

A. On any given winter day, the potential for the joint output to be less is definitely there.

Q. Then would you also acknowledge, in that case, that a key reason to install storage on a solar generator is to time shift generation from one time period to another rather than to generate additional electricity?

A. In my prior example, yes.

Q. Thus, would you say it's reasonable to assume that, if all or most avoided capacity value is allocated to the wintertime, as Duke is proposing in this docket, that a substantial portion of the use of the storage equipment on a solar-plus-storage facility would be used in the wintertime; is that fair to say?

A. No. I think, if you have a storage device, you're going to use it every day. To the extent there is -- once you've sunk the cost into a storage device, if there is a daily energy arbitrage to be had, winter, spring, summer, fall, that sunk cost is going to be offset by, on any given day of the year, ensuring that you put energy in to the extent you can based on its configuration in the off peak and discharging it on the on peak 365 days a year.

Q. That's all I have. Thank you.

CROSS EXAMINATION BY MR. DODGE:

Q. Good afternoon, gentlemen. I'm Tim Dodge of the Public Staff. Sorry. Working our way down the table. I will try to be -- I've shortened mine a little bit as a result of some of the other questions that have been raised, but I have also some points I think I want to follow up on as well that have been added. So, Mr. Snider, most of my questions are going to be directed at you, but certainly of either of the other panelists have input on the questions, I'd appreciate their thoughts as well.

So, Mr. Snider, as you discussed yesterday with Ms. Bowen, you were one of the witnesses in several of the avoided cost proceedings, most recently the Sub 148 proceeding in the 2016/2017 timeframe, correct?

A. (Glen A. Snider.) That is correct.

Q. I wanted to make a couple of references to your testimony and the testimony also of Duke witness Sammy Holeman from the Sub 148 proceeding.

MR. DODGE: May I approach the witness?

CHAIR MITCHELL: You may.

MR. DODGE: I have copies of those testimony just for Mr. Snider's reference as we go through these sections here.

Q. Why don't you flip to those? The first page I'll have you turn to is your testimony is the Sub 148 proceeding. I believe this is on pages 24 and 25 of your testimony.

In this section, you're discussing unscheduled and unconstrained QF generation, particularly from solar resources, correct?

A. Just one second.

Q. Sure. Take your time.

A. (Witness peruses document.)

Yes.

Q. All right. And the question that was put forth to you was, "Please expand on how ancillary impacts of solar generation may influence the types of new generation and future resource plans." And you responded, "The ancillary services impact of high levels of must-take solar may need to be considered in future plans when recommending the type of resources needed to satisfy winter reserve margin requirements and to ensure adequate system ramping capability and operational flexibility." And then you reference

Mr. Holeman's testimony describing increased levels of variable unscheduled and unconstrained solar QFs may create incremental need for faster load following response generation as well.

Did I read that correctly?

A. Yes.

Q. Okay. So now, if you could turn to the second tab and Mr. -- that's going to be Mr. Holeman's testimony, on pages 10 and 11. And in this section, Mr. Holeman defines or explains what the utility meant by "unscheduled and unconstrained solar." And again, the question put to Mr. Holeman was, "Please explain what the Companies mean by unscheduled and unconstrained solar QF energy and why it is now impacting the reliability of system operations." To which Mr. Holeman responded, "Solar QFs inject energy into the BA without any day ahead or intraday scheduling coordination with the system operator and without any commitment to delivery scheduled quantities of energy into the BA, and therefore are making unscheduled energy injections into the BA. Moreover, the unscheduled solar QF energy injections into the BAs are unconstrained by dispatch control due to purpose limitations, and that this is because FERC's PURPA regulations, absent contractual agreement otherwise, a QF injecting energy into a system under a contract may be curtailed and the energy injections discontinued only in a system emergency."

Did I read that correctly?

A. You did.

Q. Okay. So in the context of these statements, Mr. Holeman and your testimony, you were referring to -- generally to the day ahead or intraday basis for planning for system reliability purposes, were you not?

A. Yes.

Q. And to address the costs that are being incurred by the utility as a result of this unconstrained or unscheduled solar that was being discussed here, that is part of the basis for the utility's decision to retain Astrape to develop the solar ancillary services study that's been discussed extensively in this proceeding?

A. That is correct.

Q. All right. Now, in his testimony, Mr. Holeman also talked about excess energy situations and where the utilities may have operationally excess energy and have to dispatch down or curtail QF power and potentially sell power non-firm basis at a loss; is that correct?

A. Yeah, I believe that was the case in his testimony.

Q. Okay. And so we've talked again about the amount of solar, the amount of existing solar in North Carolina's system, but at this time, aren't most of the solar QFs in DEC and DEP's service territory operating under option B hours -- option B rate design hours?

A. Yes, that is my understanding.

Q. Okay. And do some of those operationally excess energy hours that the utilities have incurred or experienced, are those typically occurring during on-peak hours or during off-peak periods?

A. Off-peak periods.

Q. During off-peak periods. Okay.

So in the current proceeding, the Public Staff and Duke have entered into stipulation supporting the implementation of the solar integration services charge, and the purpose of that is to ensure that some of the costs of that additional load following resources that are being incurred by the utilities and ultimately being passed onto customers are assigned or recovered from the cost causers; is that correct?

A. That is correct.

Q. I know Mr. Wheeler testified to this point as well.

Yesterday, Mr. Snider, when you were talking with Ms. Bowen, I think you stated your perspective that any energy that increases intra-hour volatility adds a cost; do you agree with that statement?

A. Yeah. The resources that create additional intra-hour volatility require -- must take resources that create that -- require us to carry more operating reserves, which results in a cost, yes.

Q. All right. And one of the criticisms that was raised by the Public Staff in our initial comments regarding the development of the solar integration services charge and also by a SACE witness, Devi Glick, was that when the utility, in developing Astrape when establishing the baseline for the system reliability, the base case, Duke used a no-solar scenario that didn't include existing utility solar; is that correct?

A. Yes.

Q. All right. And why -- why -- if you could refresh my memory, why did the utility believe it was appropriate for the utility-owned solar to not be included in that baseline?

A. I think, in the baseline, what we're looking at is must-take unconstrained under PURPA. So utility-owned solar is not subject to PURPA. We don't have -- we can -- if we're in excess, we can curtail it. I think -- and I'm not the expert on this, but I believe we've agree that we are curtailing ours in advance of QF solars, subject to check. And so we were looking specifically in the study at the impact of the must-take uncontrolled under PURPA where these situations that Mr. Holeman was describing under PURPA apply.

Q. But you would agree that those -- the utility-owned generation does still result in increased intra-hour volatility that must be -- requires additional load reserves, load following reserves?

A. Yes.

Q. And in the stipulation, the parties also agreed that it was appropriate going forward to consider the ancillary services cost of adding incremental solar, such as in CPRE -- future tranches of CPRE that we would consider how to address those additional ancillary service costs caused by those intermittent resources?

A. That's is correct.

Q. As part of the stipulation -- and again, this was discussed yesterday between you and Mr. Smith and Ms. Bowen -- the parties agreed that a negotiated QF facility could seek to demonstrate and contractually agree with the utilities that -- based on its operational characteristics, that it could reduce the need for additional load following generation and no longer be subject to the solar integration service charge, correct?

A. That is correct.

Q. And specifically in the stipulation, wasn't the addition of energy storage system one of the examples that was listed?

A. It was.

Q. All right. But as you've indicated, a battery by itself doesn't reduce volatility, it's how it's operated and the operational constraints or controls that would be in place on that battery?

A. That is correct.

Q. And in the context of the stipulation, we also agreed that, for currently exempt projects, or the grandfathered existing QF facilities, that they would not be subject to the solar integration charge until they come in to renew or until the time of their current PPA term expires, correct?

A. Right.

Q. So if one of those facilities, you know, a facility that may be on an option B Sub 136 or Sub 140 rate, wanted to make changes to its facility to avoid the charge, it doesn't have an incentive to do that currently for purposes of avoiding the solar integration charge?

A. That is correct.

Q. All right. But say if that is its goal within one year of the expiration of that PPA term, it could file a new -- establish a new LEO with the utility, seek to commit to selling its output, and at that point it may be able to make the modifications that we've described here to seek to avoid the application of the charge going forward?

A. Yes.

Q. So thinking back to some of those facilities that may want to make those modifications, if they don't have an incentive under the integration charge to modify the facility to avoid that charge currently, those facilities -- I think yesterday you described the idea that, for the utility to be receptive to allowing those modifications, there would be need to be a benefit to customers. Customers would -- they would need to demonstrate that customers would benefit as a result of that modification to the facility.

Do you recall that discussion?

A. Yes. I think yesterday and today I was testifying to the extent that that is consistent with my read of House Bill 589.

Q. Okay. And I know we talked about the indifference point, I think you made some references to -- and I won't try to use the hamburgers and the fillet mignon analogy that was used yesterday.

A. Thank you.

Q. But to the extent that there are -- there's different ways you could view indifference, and I just want to make sure I'm following the way that you are interpreting the indifference principle for PURPA purposes.

I think you indicated that this point is basically when a customer is indifferent between whether that megawatt hour that's required by the utility to serve load comes from either the utility or a QF; is that correct?

A. Right.

Q. Okay. And this Commission makes that

determination every biennial proceeding as to what the appropriate indifference point is for the purposes of that proceeding, correct?

A. That is correct.

Q. But customers are not indifferent between energy purchased under older avoided cost rates and that may no longer be representative market conditions and current avoided cost rates necessarily, are they?

A. They are not.

Q. And you've described some of the costs that customers are currently paying for under some of those older contracts currently.

In addition, would you say that customers are indifferent between a megawatt hour that they purchased that increases intra-hour volatility and a megawatt that provides a smooth megawatt hour profile?

A. The only way they're made indifferent is if the QF is charged and that dollar is no longer being subsidized from the customer but is moved over to the cost causer, which is the QF, then they would be indifferent. Absent discharge, they are not indifferent.

Q. So the solar integration charge would seek to address that -- ensure that indifference point is still maintained for Sub 158 proceedings?

A. For incremental. We've talked at length about the exclusion for prior, yes.

Q. Okay. But again, for a facility that the solar integration charge does not apply to, is the customer indifferent between a megawatt hour that has volatility -- that increases intra-hour volatility and a megawatt hour that is being procured that would not be subject to the application of the solar integration services charge and does provide a smooth profile?

A. I'm sorry, I lost you there. Could you restate your question?

Q. Sure. So to the extent a facility is not subject -- so an existing facility that's been grandfathered and would not be subject to this whole integration services charge at this time, is the utility indifferent between a megawatt hour that that utility -- or that facility produces that further increases intra-hour volatility and an -- or -- and an hour that that facility produces that provides a smooth profile and does not increase intra-hour volatility?

A. I'm trying to see if I understand your question. So if that legacy facility had certain hours where there was intra-hour and some where there were not, the one where there was not intra-hour volatility, all other things being equal, would be preferred.

Q. And the only way that they could reasonably do that would be to modify the facility to add storage or subject to an energy storage protocol that would provide some of those -- a protocol that was designed to provide for smoothing, that's the only way they could provide that kind of smooth profile?

A. Right. I think we've had the extensive -- the mere existence of the battery will not do that for an existing facility. In certain instances could actually exacerbate the intra-hour volatility.

Q. Okay. Thank you. Earlier today you -- just a few moments ago you were discussing with Ms. Kemerait whether the utility would be indifferent between an energy storage facility, and I believe you described a peaker facility that was following an AGC signal; do you recall that discussion?

A. Yes.

Q. And is Duke -- you're familiar with Duke's -- Duke Energy Progress' Hot Springs microgrid project?

A. Yes.

Q. And is that facility proposed to operate following an AGC signal as well?

A. I believe it was. I did not participate in that proceeding, but my general understanding is yes.

Q. Okay. All right. Thank you. So -- I covered some of this already. So let's go ahead and shift gears a little bit. This is still primarily directed at Mr. Snider, but, Mr. Wheeler, you may be able to answer some of these questions.

Mr. Snider, did you read Public Staff Witness Jeff Thomas' June 21, 2019, testimony in this proceeding?

A. I did review it.

Q. On page 23 of his testimony, he discussed the solar integration services charge that Duke is seeking to apply and possible overlap with Dominion's redispatch charge; do you recall that discussion?

A. Yes, I do.

Q. The utilities didn't respond to that statement in rebuttal.

Do you believe -- does Duke believe that there may be some overlap between the cost that each of those studies identified?

A. We didn't respond because I did not do the Dominion study, but in my review of it, as I understand it, and subject to the Dominion witnesses coming up after me, their model is at an hourly level, and it looks at the some of the impacts of commit and dispatch at the hourly granularity.

The Duke approach that Astrape took focused solely on the sub-hourly operating reserves that happen at intra-hour. So there are differences that Duke has not addressed that happen at the hourly level. Again, when we file an avoided cost rate, we use a generic base load resource, so 8760 hours a year, that resource is available. We look at the difference between the availability -- or the cost with and without that resource, and then we apportion it into these time buckets.

There are some hourly differences that occur with an intermittent resource that we've responded to in data requests subsequent to our filing that show a difference between had you done that same analysis looking at an hourly level, you get a little bit different result then you would if you assumed a base load resource. We did not address that in our solar integration charge. We focused on the sub-hourly.

It's my understanding that Dominion's look more at the hourly. So I'm not saying there isn't an overlap, because, again, I haven't reviewed their study in any detail, but I would say they focused on two different aspects at different time steps, which, you know, Dominion, to my knowledge, did not look at the sub-hourly, you know, five-minute deviations that require, and ours did. And conversely, they looked at some hourly impacts that we did not.

So I -- again, there is certainly a potential that, to take the collective impact, we could have both come up with something lower -- or higher integration charge that would have resulted in a lower net revenue for the QF community. I think this is another example of where we're being a bit conservative in our approach and really stepping into this in a thoughtful manner.

Q. Thank you. And this may be more a question for Mr. Wheeler. Just to clarify -- and this has come up in discussion as well with you, Mr. Snider.

But on page 4 of your testimony, Mr. Wheeler, you describe that there is an existing subsidization resulting from the exclusion of existing solar QFs from the application of that solar integration services charge; do you recall that discussion?

MS. FENTRESS: Can counsel identify what testimony?

MR. DODGE: I'm sorry. And I did not

note that in my testimony -- or my notes here.

THE WITNESS: (Steven B. Wheeler.) I believe that's my direct.

MS. FENTRESS: Direct?

THE WITNESS yes.

MR. DODGE: I believe it is direct.

A. (Steven B. Wheeler.) Yes, I made that statement.

Q. Okay. And by this statement, just to clarify, you mean that there is a continuing subsidy -- ongoing subsidy that results from those costs not having been included in the calculation of avoided costs in prior avoided cost proceedings, correct?

A. Not really in the avoided cost, themselves, but because the solar intermittent generation is located on the system, it has been causing us to incur a cost. We're not going back do those customers who had previously contracted with us and trying to recover those costs directly from them, even though they are the cost causers of those costs.

And so because of their approach of phasing this in over time, they will eventually be charged if they decide to renew or accept new contracts when this current ones expire, but until then, those costs will be absorbed by the general body of customers through cost of service of retail rates.

Q. Okay. Thank you. And one last question regarding the stipulation that I wanted to clarify a point.

Yesterday Mr. Smith asked Mr. Snider about the amount of solar that was included in the change case for -- calculation of the solar integration charge for the purposes of this proceeding and how Tranche 1 projects that were selected that included energy storage would be modeled.

Do you recall that discussion?

A. (Glen A. Snider.) I do.

Q. Okay. And to be -- just to be clear, for the purposes of establishing the Sub 158, the solar integration service charge for this proceeding, that's based on existing plus transition solar -- the existing plus transition solar scenario and does not yet include the CPRE Tranche 1 generation; is that correct?

A. Yeah. Just to be clear -- and I may have misinterpreted or misspoke on that point -- the integration charge was calculated, in this proceeding, just on existing plus transition. So we did not include CPRE future tranches as -- you know, again, that are yet to be contracted for in the calculation of the integration charge.

Recognizing that our approach is to update it every couple of years, to the extent those come into service, they would affect the next charge. But the solar integration service charge was strictly calculated based on existing and transition which resulted in a lower charge than you would have used had you used a higher amount of solar.

Q. Okay. Thank you for that. And one last question for Mr. Snider.

Yesterday you mentioned there was finite need for energy storage resources in the utility service area and that the utility's preference was to procure those resources through a competitive procurement process; do you recall that discussion?

A. I do.

Q. And as noted by Mr. Quinn today, the utility's IRPs do include placeholders for significant energy storage resources over the planning period; is that correct?

A. Yes.

Q. Has Duke done any analysis or estimates of what that finite level of energy storage resources would be for its system?

A. No. We have not done analysis to say -- when I say finite need, I was speaking more generally that any resource has a limit to how much value it creates. So you have so much peaking resources, so much intermediate, so much base load. And it's just a general principal within planning that, if you try and put too much of any of those peaking, intermediate, base load resources on, that next increment does not have value or it's detrimental. So it's more of a general statement.

With that said, certainly it's a topic of additional study that will, I'm sure, take place in not only these proceedings and IRP and CPRE, but we will continue to study as battery storage technology evolves, the role that storage plays and the appetite that each of the systems has for four-hour battery storage, or any hour battery storage, for that matter.

Q. Thank you. And I believe the remainder of my questions are for Mr. Johnson.

Mr. Johnson, just one point of clarification. Do you have your summary with you?

A. (David B. Johnson.) I do, yes.

Q. And on the summary, on page 3 of your summary, line 4, you describe the energy storage protocol and indicated that the Public Staff agreed with the energy storage protocol for purposes of the standard offer facilities.

And I just want to clarify, subject to check, would you agree that Public Staff Witness Thomas' testimony states that the Public Staff does not have -- and this is on page 30 to 31 of his testimony, that, "We do not have the expertise to determine the appropriateness of the energy storage protocol, but we do recognize that some operation guidelines for facilities incorporating energy storage devices is appropriate"?

A. Yes, I agree, subject to check.

Q. Okay. Thank you. Also wanted to discuss briefly with you the term "estimated annual energy production" that's included in your testimony and is also incorporated in Duke's definition -- proposed definition of material alteration.

Now, as you discussed with Ms. Bowen yesterday, the term is an existing term in Duke's PPA in terms and conditions; is that correct?

A. Yes.

Q. All right. And how does Duke monitor and track whether the facility is operating in compliance with that estimate?

A. I would say we don't continuously monitor that, but if we do see some irregularities, you know, it will come to our attention. But we don't have a process in place to, you know, continuously monitor that.

Q. And I believe, Mr. Wheeler, in those same discussions yesterday, you indicated that it's Duke's perspective that the energy output from year one, which should be reflective of that estimated energy -- annual energy production, should generally be the same at year 15; did you not?

A. (Steven B. Wheeler.) Yes, I did make that statement yesterday.

Q. Okay. And when Duke's seeking to enter into or execute a PPA with a QF, does the utility make any kind of preliminary reasonableness assessment as to that estimated annual energy production value that's indicated in the PPA?

A. (David B. Johnson.) I would say yes.

Q. And is that information compared with -- evaluated for consistency with the interconnection request that that facility may have submitted?

A. I think it is, subject to check, yes.

Q. And as a result of the added emphasis on this provision, the new material alteration definition proposed by the utility, does -- would there be changes going forward on how that estimate is tracked or evaluated by the utility?

A. We -- I would say we are evaluating what ways to track that. It is just -- trying to get our hands around all the data is the critical piece.

Q. Now, in your rebuttal testimony, page 11, I had a quick question about a statement you made there as well. This is Johnson rebuttal page 11. On line 7 you indicate that, "The Companies anticipate developing specific requirements in the coming months and will make them available to QF developers seeking the negotiated PPA that proposes to integrate battery storage."

Can you comment on how the development of those specific requirements will be -- will they be incorporated or included in the stakeholder meetings as part of the CPRE, or included also in discussions taking place in the North Carolina interconnection process related to the incorporation of existing -- energy storage to existing facilities?

A. I don't think this time we have decided how we're going to go about that. We just recognize that -- through this proceeding, that that is something that we need to look at and evaluate.

Q. All right. And then one last question regarding the -- on page 12 of your rebuttal, this is dealing with the Company's process for allowing an existing QF to seek to enter into a new PPA. And you state that, "To ensure that the QF will be paid reasonably accurate avoided cost rates at the time of the delivery, the Companies do not accept requests to enter into a new PPA earlier than 12 months or one year prior to the end of the QF's existing PPA term."

How does this compare with the time frame that a new QF seeking to enter into a -- establish a LEO and execute a PPA would be subject to?

A. Well, traditionally a new QF, especially if you're talking about a -- I mean, there's a difference between standard and noneligible standard QFs, because of mainly the interconnection process. For a standard, let's say the interconnection process, even for that is -- you know, there is some amount of time that that QF will have to wait until they're interconnected and the facilities are constructed versus an existing QF.

For a negotiated, as I mentioned -- negotiated QF or PPA -- the new -- the new interconnection process is quite lengthy, or it has been. And so, I mean, it can be two to three years or even more. For an existing, you know, you don't have that lengthy process. They've already developed their facilities, the interconnection has, you know, been approved, and it's in operation.

Q. So a -- potentially an existing facility that is operating and is already interconnected doesn't have to go through those, may have to wait until much closer to its operation or renewal date before it could commit compared to a new facility that's still subject to the uncertainties of the interconnection process?

A. Correct.

Q. Okay. All right. Thank you. No further questions.

CHAIR MITCHELL: Redirect?

MR. BREITSCHWERDT: No redirect for Mr. Snider.

MS. FENTRESS: No redirect for Mr. Wheeler and Mr. Johnson.

CHAIR MITCHELL: Questions from the Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Gentlemen, I'm just going to ask my questions to the air, and whichever one of you wants to field it can field it.

In your initial submission, you did submit proposed initially the rate design, and you had assumed certain inputs into that rate design that you modeled and spit out as one of the exhibits a set of proposed rates for the standard offer. We're at a point now where you've got a stipulation on a different rate design with the Public Staff, and I understand -- fully understand from your testimony, of course, that you still don't know what decisions the Commission might make about some of the model inputs, principally the fuel costs. So I'm going to ask you to make a couple of assumptions and see if you can do something for me.

If you take the proposed rate design that's in the stipulation and then you use the same model inputs that you used in your initial submission, how difficult could it be, how quickly could you rerun proposed rates for the standard offer now as a late-filed exhibit?

A. (Glen A. Snider.) Commissioner Clodfelter, I apologize, I may not have fully caught that.

Q. Make the same assumptions that you used in your initial filing as to fuel costs and any other assumptions. Make the same assumptions, use the rate design that you stipulated to with the Public Staff, and rerun.

A. That is what we filed in the stipulation, so.

Q. I missed it. Is it there? Our staff may have missed it too.

A. In the stipulated design, we filed a new set. I'm looking for a page reference here.

(Pause.)

MR. BREITSCHWERDT: Commissioner Clodfelter, can I --

COMMISSIONER CLODFELTER: If you've got it, that's fine.

MR. BREITSCHWERDT: I don't believe it's in the stipulation. I could present the stipulation to the witness and allow him to refresh his recollection.

THE WITNESS: We could do it quickly.

COMMISSIONER CLODFELTER: I don't want to waste time on it. If it's there, you can just tell me during the break where is it, and I can find it and feel like an idiot for not seeing it.

But if you haven't run it, rerun it. That's what I'm asking for.

THE WITNESS: We can have that -- if it's not in there, we will have it as a late-filed exhibit very quickly.

Q. There you go. Thank you. And let's pick up on another question that was asked of you yesterday. And with apologies to your counsel, I'm going to preface the question with an opening statement. I have to do it to be sure counsel understands why I'm doing it.

You know, one thing that's really changed since 2016 proceeding is that the General Assembly of North Carolina has now taken this concept of avoided cost and imported it into some completely non-PURPA programs. And so I have to deal with the fact, in this proceeding, that the rate we set in this proceeding is going to have operative effect in some non-PURPA programs of the State of North Carolina. I have to deal with that. I cannot be in a silo and not deal with it. Apologies to your counsel. I have to.

So how difficult would it be for you to run the 20-year avoided cost rates using the rate design in the stipulation and the same model inputs? The rates that would be used for the CPRE Tranche 2.

A. So we could do that fairly expeditiously. I would say our standard practice, though, has been to update -- even the -- you know, the gas prices have changed since, you know, back last summer.

Q. I'll give you that. I'll give you that.

A. Okay.

Q. I'll give you that.

A. Okay.

Q. Update the current gas prices -- update the current gas prices, but use --

A. With this design, 20 years forward, we could do that.

Q. That's late-filed Exhibit Number 2.

A. Okay.

Q. Got it. Thank you. There has been a lot of testimony about contract terms. And whenever I hear people asking questions about contract terms and talking about contract terms, I want to pull the contract. And so I'm going to ask you some questions about the contract terms. Who is best to answer those? Okay. What I've done is just -- and because of time, I pulled the Sub 148 documents, the PPA and the terms and conditions.

Now, I don't know to what extent those changed in 148, I wasn't here, and I just haven't had time in preparation for the questions to go back and pull the prior one, so I may have some questions, you will say, well, that really doesn't apply because that was a new term in 148, so we'll deal with that when we get to it. I want to ask you about paragraph 7 of the terms and conditions in Sub 148.

A. (David B. Johnson.) Excuse me, you said Sub 148?

Q. Yeah. Yes, sir. I'm sorry for the yeah. Yes, sir.

A. And this is the contract renewal?

Q. Yes.

A. Okay.

Q. Yes. There's been a lot of back and forth about what happens and who has what options and what choices at the point of expiration of the contract term. As I read this, the Company is the one that has the option to renew. It's the Company's elections to whether or not to renew the agreement for an additional term. It's not the QF's option. I mean, the QF can surely use -- you know, use its option under PURPA and establish a new LEO, but under the contract, the company can elect to renew the existing contract. Why am I reading that wrong?

A. (Steven B. Wheeler.) I think the Company has an obligation to purchase from the QF.

Q. That's the PURPA obligation, but you have a contractual right to renew this contract if you want to. Am I wrong? Isn't that what it says?

A. Well, it says to be subject to renewal for subsequent terms at the option of the Company on substantially the same terms and provisions at a rate either mutually agreed upon by the parties negotiating good faith and take into consideration the Company's then avoided cost rates.

Q. Right. Right.

A. And other relevant factors are set for arbitration.

Q. So if you want to renew these -- all of your existing QF contracts at the expiration of their term at your then point of renewal --

A. Right.

Q. -- avoided cost rates, you have the option to do that.

Is that the way your contracts have read since prior to 148 -- Sub 148?

A. I don't believe this provision was changed with Sub 148, so I think that's a longstanding provision in the terms and conditions.

Q. Have you exercised that option?

A. We renew customers who want to sell to us. We execute a new PPA with them at the current prevailing rates that applied at that point in time. We don't really view it as their option, we view it as their obligation because they are a QF. They qualify to sell to us, and we're required to purchase from them. So we kind of overlook the provision that says "at their option," because we think it's at our obligation because of PURPA requirements.

Q. But when you do the renewals, as you have done them, you do it at the then current avoided cost rate?

A. Right. Or if they don't renew, then we automatically extend the term of the contract under the as available rate, which is a variable energy rate.

Q. You do that, your option?

A. Because they haven't told us anything different. That's the default rate if they don't take any action at all at the expiration of the contract term.

Q. Thank you. I just needed to get a baseline. I mean, there's been so much back and forth about who has what rights at what points, I want do go to the actual agreement between the parties and see what it says about their rights. Stay with me on that agreement, because I want to ask some other questions about it.

So the only two things I see that are sort of stipulated and fixed in the PPA and the terms and conditions -- again Sub 148 is the only one I've pulled, it's the only one I'm looking at -- are nameplate capacity and something that's called the contract energy, which is the estimated total annual kilowatt hours registered or computed by or from the Company's metering facilities for each time period during a continuous 12-month period.

Those are the only two things I see that are spelled out. The nameplate capacity -- well, excuse me, there's a third one, but it's really not material for my question, the location. The nameplate capacity, the location, I don't care about location, and the contract energy, the estimated 12-month production.

A. Yes. Those are both spelled out and scheduled PPA --

Q. Right.

A. -- as well as -- and the purchase power agreement leaves a blank for both of those --

Q. Exactly. And then it's also defined in the terms and conditions consistent with PPA?

A. Yes.

Q. Right. So if I don't change those -- if I make a change in my equipment of my existing facility that doesn't change either the nameplate capacity or doesn't change the estimated total annual kilowatt hours registered or computed over a 12-month interval, why is that a material modification? Point me to the provision in the existing contract that says a change of the type I just described is a material modification. I haven't changed either of those things.

A. I think the Company's interpretation goes back to the fundamentals that we use to set the rates, and a fundamentals we use to set a levelized rate is an expectation over the term of the contract, generation profile being unchanged. Recognizing that run-of-the-river hydro, for instance, can't produce the same amount of electricity every year because of water flow, and solar has some degradation over time on their output, but the expectation from a ratemaking perspective is the generation profile be unchanged over the term.

Q. Mr. Wheeler, you provided for those kind of variations in paragraph 4C where you take into account changes of water flow, steam supply, or fuel supply, but it doesn't say anything about solar facility variations in the operation of a solar facility in terms of a production profile. It just stipulates that there has to be the total annual kilowatt hours computed for a continuous 12-month period. That's the contract energy capacity.

So where in the contract is a change that doesn't affect that total a material modification?

A. Well, in 4B it does talk about the contracted capacity or contract estimate annual energy production without adequate notice to us and prior consent. So it talks about if you want to change it. I think our view is, when you fill out the purchase power agreement, you identify what the facility is. If you're making a change to those facilities, that constitutes a material change, regardless of how is it affects your output. That qualifies as material change, especially if it's going to change your generation profile.

That is material change. That is a harm to ratepayers and customers who have an expectation of levelized continuous load profile over the term of the contract.

Q. What I'm struggling with, as I read the contract, the production profile --

A. Is not specified.

Q. -- is not called out. What's called out is the total estimated annual kilowatt hours delivered to the grid. But the actual production profile is not called out anywhere in the contract, and that's what I'm really trying to get a handle on.

Now, in fact, it even -- and I understood Mr. Snider -- you I'll wait. May want to chime in on this one. Mr. Snider was explaining earlier this morning that, well, if you've got a battery added to an existing facility under contract, that you've got to charge the battery, and that's going to reduce the total kilowatt hours delivered to the grid. Right, so that does change maybe the annual. But the contract provides specifically for that. It provides that, if the average energy generated in the 12-month period falls significantly below the contract energy, the Company can petition for a reduction in charge and reduction credit.

So haven't you already covered that case where the battery is added and it reduces the total energy production? Haven't you already covered that case in the terms of the contract?

A. I think there are provisions in here if the profile does change, go in and try to adjust or charge the customer for the harm done to the retail customers. So I think it is covered in here already.

Q. The harm is -- that's covered is loss or damage to the Company's facilities, not to the customers. I'm working very hard to sort of figure out why this contract, as I read it in Sub 148, makes the addition of battery storage a material modification.

A. Well, I would say that the terms and conditions are living documents. As conditions change over time, I think most provisions in here were created in an era where you didn't have solar generation at all; all you had was cogeneration, primarily. And I think, over time, we recognize some of the deficiencies in the terms of conditions. And that's the reason we're seeking changes this time, to clarify things like material alterations, to make certain it is more clear to sellers in the future exactly what is met and how it's interpreted by the Company.

Q. It's great thing to make it more clear to the sellers in the future to go forward. I'm really grappling with a case that I think Mr. Dodge was addressing in some of his recent questions of where you're trying to get the system value to the customers of an existing facility that's not going to be subject to the system impact charge but may want to smooth out by adding battery storage or may want to take advantage of some other operating improvements by adding battery storage to that existing facility. I'm trying to figure out why we can't do that under the existing contract terms.

All right. I'm going to leave that one alone, unless you've got something else you want to tell me about it. But I think you know what my concern is. I think the Company knows what I'm interested in on that point.

A. Let me see if Mr. Johnson would like to add anything.

Q. Okay.

A. (David B. Johnson.) As I said earlier in answering a question, I think that fundamental premise of the agreement between QF and Duke in this case is that the PPA is supposed to represent the facility that the QF is building, and simply put, if during that PPA term a QF modifies that facility, we think that's a change that wasn't -- you know, that wasn't intended for that PPA.

Q. I understand. Again, as I say, where I read the contract, there are certain modifications that are very clearly identified as things that are material changes, but then there are others that are not. And I'm trying to understand how everything becomes a material modification when only certain things are called out in the contract. I'll leave it alone. I'll leave it alone. I think that's the issue.

Coming back to Tranche 2, again with the apologies to your counsel. So I like the idea that you're going to be offering an exit ramp from the system integration charge under certain circumstances and certain conditions. So we're coming up within a matter of weeks, literally within a matter of weeks of opening the document review process in Tranche 2. And so if I'm going to be a market participant who is going to consider bidding in Tranche 2, I really want to know, probably by the beginning of the contract review period, what is your fully dispatchable PPA option going to look like.

I understand, Mr. Snider, from your testimony, that's one option for avoiding the charge is offering up a fully dispatchable PPA.

A. (Glen A. Snider.) As one tool that --

Q. As one tool. When am I going to be able to see an example of what Duke proposes for a fully dispatchable PPA contract? We're literally weeks away from the document review process. When am I going to see what exactly the final storage protocols are going to look like so I can know whether or not to include those as a component in my project that I'm going to bid in?

We're literally on the doorstep of those things. I appreciate the attention. I appreciate the openness to negotiation and the willingness to do that. I buy it. I take you at your word. I'm worried about the timetable. And I really need some more comfort about where we are on the timetable of making those things explicit and getting them out there in the public, having people touch them and feel them and know where they're going with them, because they're going to start bidding here in just a couple of months or so.

A. Agreed. They would need to be part of those protocol, and I think that's what we're testifying to, is when those protocol are developed, you will have to have an allowance. I agree with you that, within those protocol, you would have to have some allowance for smoothing that addressed -- and it would have to be done in time before people started bidding.

Q. I get it.

A. So we're in agreement.

Q. So I heard earlier this morning someone say it may be a matter of some months before all of this gets ironed out. That's when the red flags went up for me. We don't have a matter of months for these things. They need to be done in a compliance filing in this docket relatively contemporaneous with the document review process in Tranche 2.

Can the Company do that, is really -- what I'm really driving at is I'm looking to you guys to say can you do it? Can you get it done?

A. (David B. Johnson.) Commissioner Clodfelter, so we are -- we have been updating and evaluating the Tranche 2 storage protocols. We've gotten some input from developers. This issue with regards to the integrated system -- or integrated system or the charge, integration charge, is something that we are contemplating in the protocols. You know, the ability for the QF to either smooth their discharge, or, you know, the other way that they would do it is just to shift the energy from off peak to on peak to take advantage of the higher prices. So we're looking at that. Beyond that, we haven't developed any other PPA language for that, so that's something I think we'll have to evaluate.

Q. Well, First Solar had brought us in -- at the technical conference or CPRE Tranche 2 -- had brought us a proposed -- a fully dispatchable PPA.

Has the Company done anything to advance the review of that or analysis of that option?

A. (Glen A. Snider.) Yeah. And again, if it was a battery standalone, that could make some sense for a battery standalone, because it's a dispatchable asset and, you know, there's industry standards out there for dispatchable assets to sort of get a capacity payment and then a small variable energy charge or an index tolling agreement PPA.

What's difficult when you pair, for example, an 80-megawatt solar facility with a 10-megawatt battery, you still, by and large, do not have a dispatchable. There's still a tremendous amount of volumetric risk and how much volume you're going to get. And so you don't have control of -- it's truly not dispatchable when you pair a large solar facility with a small battery.

So, you know, we don't see a way to make a dispatchable dollar per kW offering on a paired work the way First Solar has been ascribing. We think it could make more sense than just a pure battery situation where you actually would have something that gives you maybe a day ahead -- you know, if you give me one turn a day, dispatch it, you know, 365 days, each day I'm going to tell you which four hours. We could give you a fixed price, you know, for that much more readily.

So we've been looking at it, we just -- we don't -- we have not been able to come up with a way where that makes sense for consumers nor the Company to pay a fixed-price payment for a variable entity output that's not fully dispatchable.

Q. So that's probably not going to be an option in Tranche 2, an option that can be called upon to avoid the system integration charge?

A. Right.

Q. Okay.

CHAIR MITCHELL: All right. We're going to break now for lunch. We'll be back on the record at 2:00.

(The hearing was adjourned at 1:01 p.m. and set to reconvene at 2:00 p.m. on Tuesday, July 16, 2019.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 24th day of July, 2019.

JOANN BUNZE, RPR
Notary Public #200707300112