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

Commissioner ToNola D. Brown-Bland

Commissioner Don M. Bailey

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Lyons Gray

IN THE MATTER OF:

General Electric

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

VOLUME 4

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CHAIRMAN FINLEY: All right, ladies and gentlemen. Let's reconvene the hearing, come back on the record. We have continued cross examination by the intervenor parties. Who's next?

MR. CULLEY: Thank you, Mr. Chairman. Thad Culley for Cypress Creek Renewables. Oh, I'm sorry. I've been informed counsel for SACE has one concluding question. I think she --

MS. BOWEN: Thank you, Thad. Mr. Chairman, at the end of the day yesterday we did forget to ask that our SACE cross exhibits please be -- we'd move that those exhibits be added to the record.

CHAIRMAN FINLEY: If you will hold that until we get through with the Panel, we'll pick up all the exhibits at that point.

MS. BOWEN: Excellent. Thank you, Mr. --

CHAIRMAN FINLEY: I haven't forgotten about them.

MS. BOWEN: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: All right.

CROSS EXAMINATION BY MR. CULLEY:

Q All right. Well, good -- good morning, Panel.

A (Freeman) Good morning.

Q As I mentioned, my name is Thad Culley. I'm counsel for Cypress Creek Renewables. I will try and get through these questions as quickly as possible today. So I'd like to start with Ms. Bowman. Let's discuss what I'll call the half-mile rule that was discussed in your testimony. So would you agree Duke has proposed some modifications to the terms and conditions of the standard offered PPAs in this proceeding as it relates to the half-mile rule?

A (Bowman) Yes.

Q And one of those modifications would prevent a party that owns a project with the standard offer PPA from selling that project to another party that owns another standard offer QF project using the same energy resource that's located within a half mile; is that correct?

A Could you repeat that? I need to follow the question.

Q Right. So I'll -- I'll see if I can paraphrase and simplify that one.

A And where are you reading from in my testimony?

Q Oh, I'm not reading from your testimony. This is just a general question about what Duke's proposal is.

A Can you point me to where in my testimony I talk about the half-mile rule?

Q Yes. Let's go to your direct testimony, page 55. And I believe the reference line numbers you're going to need there are going to be -- I think 10 through 11 you discuss the rationale.

A Okay.

Q Okay. Perhaps in your words could you explain what the half-mile proposal is in this case?

A So I believe this is intended to try to prevent kind of combining facilities that are too close together that kind of evade the -- the half-mile rule, so they're intended to prevent that through consolidation of ownership of QFs after their PPAs or another standard offer have been executed. So this is trying to prevent gaming of the system of the half-mile rule once those facilities have been constructed.

Q Okay. So maybe we could discuss what the current standard is. So Duke's current standard offer rate schedules already provide that a QF is not eligible through the standard offer if it is under common ownership with another QF that is located within a half mile and uses the same energy resource; is that -- is that correct or not?

A That is correct.

Q And I believe you just stated your understanding of the rationale Duke has now proposed for -- for this modification. And to be clear, I don't think we answered the first question about what that modification is. It's now saying that if two projects are owned by separate entities within a half mile, this rule would prohibit the sale of that QF to make it under one common ownership; is that correct?

A That is my understanding, yes.

Q So if the original rule was to prevent gaming and to -- to, you know, prevent that -- we'll say to ensure that QF developers don't circumvent the 5 megawatt standard offer by breaking the projects up into -- into, you know, multiple adjacent projects, you know, that -- that was the original intent; is that correct?

A That is my understanding.

Q Would you agree that the only effect of the Companies' proposal now would be to prevent the owner of an existing standard offer project from selling that project to a developer who owns a different project using the same energy resource located within a half mile?

A No. I don't believe the intent is to prevent them from purchasing it. I just don't think that they should be allowed to combine it to circumvent the rule.

Q And what public policy is advanced by that restriction on the free buying and selling of QFs?
A I don't believe we're restricting the free buying and selling here. We're just restricting the -- the size limitation.
Q But isn't -- if two QFs have been properly developed under the standard offer tariff by two separate developers and a QF owner who buys a nearby project isn't doing anything to game the system, I mean, would you agree with that?
A They could still have the -- the two separate agreements.
Q Right, but they -- they would not be able to buy and sell -- buy and sell that QF under the existing terms of the QF's contract with Duke; is that correct?
A I'm not sure I'm understanding what they can't buy and sell.
Q So if there are two QF projects under separate ownership --
A Under separate ownership, correct.
Q -- that are within a half mile, and the owner of one acquires the other, both had independently secured the standard offer contract, does the act of consolidating ownership have a consequence that

terminates that PPA?

A I don't believe it does.

Q And let me just ask, do you have any evidence that developers are deliberately evading the geographic restrictions in the current standard?

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

A (Freeman) Well, clarify your question because, you know, I'll go back to what Ms. Bowman originally said that -- around, you know, gaming the system, and we do have evidence that, you know, developers in -- in some cases have proposed multiple projects, you know, within a half a mile trying to, you know, circumvent the 5 megawatt project limitation.

Q I'm sorry. Let me -- I don't think I clearly articulated that question. I actually meant to say in the context of the conversation we've been having about subsequent consolidation of those projects, do you have any evidence that developers are evading the geographic restrictions by gaming it in that way?

A No. I don't have any evidence that -- that I'm aware of at this point.

Q And for developers to do that, would you agree they would have to have some form of coordination or even collusion to avoid this limitation?

A Well, I think the question has come up, you know, in a number of cases, and -- and I'm not clear on the resolution, but as, for example, your company, Cypress Creek and FLS, when there was a merger of those companies, I think it did call into question some of the projects that were owned by -- by both -- both entities. And I -- I don't recall what the resolution of that was.

Q But as -- as you say, there's no evidence that developers have deliberately tried to evade this restriction by subsequent consolidation?

A No. I'm not aware of any evidence.

Q Right. But that is the rationale Duke has put forward for proposing this modification; would you agree?

A I -- I don't have enough information to -- to really, you know, really answer your question. I'm sorry.

Q Okay. No. Thank -- thank you. Thank you. And do you agree that the proposed -- I'm sorry, let me get some water -- that this proposed restriction would apply even if there were no indication that gaming was going on, in other words, completely innocent consolidation of two projects within a half mile of each other?

A I'm sorry. So ask your question again.

Q So let me simplify this one again. So I think you would say this restriction would apply even if there is not nefarious collaboration or collusion going on; is that correct?

A As I understand how the, you know, the proposal is written, yes, I think you're correct.

Q And this would apply to two nearby projects even if they were built by unrelated developers?

A Yes.

Q And even if they were built years apart?

A Yes.

Q And I believe we've touched on this a little bit, but maybe you could expound on Ms. -- Ms. Bowman's answer. But what would be the effect on a QF if it violated the term of -- of the PPA, this term that is being now proposed?

A Well, again, I'm not intimately familiar with -- with the proposed change, but I think Ms. Bowman answered the question and said that or implied that the potential for the contract to be terminated would -- you know, the standard contract would be terminated.

Q Okay. Thank you. So with that result, would you agree this is a pretty restrictive condition?

A You know, define "restrictive." You know, let me just kind of elaborate. I mean, we -- we've seen projects change ownership now as many as five times, and trying to maintain, you know, an understanding of who even owns these projects has been a tremendous challenge for us. I mean, you know, five times has been the extreme so far, but -- but we've seen projects change ownership, you know, two -- at least two times, many, many, many times three and four times. So it's just been a challenge to keep up with -- with who owns these projects.

Q But -- but you would agree this condition is more restrictive than the status quo? That -- I think that's really the question I was asking.

A Yes.

Q Okay. Thank you. And so let's just recap this, and we can -- we can move on. So the Company proposes to prohibit a developer from ever owning more than 1 megawatt solar QF within a half-mile radius. Would you agree with that statement?

A I -- I'm sorry. Ask the question again.

Q So the Company proposes to prohibit a developer from ever owning more than 1 -- 1 megawatt solar QF within a half-mile radius?

A (Bowman) I don't necessarily believe that

that's the -- the case. I believe that it restricts them to the standard offer terms and conditions. If they want to build a facility larger within a half mile, they're certainly welcome to do that. They would just be entitled to the negotiated rate, not the standard offer rate.

Q Okay. Understood. Thank you very much for that clarification. And this would be the case even if there's no indication of an attempt to evade the standard offer threshold?

A Yes. I mean, the -- the purpose of this is to try to avoid the gaming of the standard offer. Again, all of our efforts in this proceeding are to provide just and reasonable rates to our -- our customers, while at the same time balancing PURPA's objectives of promoting QFs. And so this is to avoid the gaming of that standard offer, and if they want to build a facility or buy a facility that's larger than that standard offer, then the developers certainly have the opportunity to do a negotiated contract.

Q Okay. Thank you. But lastly, there's just -- just to -- just to wrap it up, there's no evidence that this has -- this is happening, that this is a major problem?

MR. BREITSCHWERDT: Mr. Chairman, objection. I think this question has been answered at least twice now.

CHAIRMAN FINLEY: It has been answered.

MR. CULLEY: Thank you. I'll move on. Thank you very much.

Q Okay. Ms. Bowman, I have a few questions for you related to solar integration and ancillary services, and -- see if I have a -- and do you recall in your testimony indicating that it may be possible in the -- moving forward in the future that Duke would include certain solar integration or ancillary generation services cost in a negotiated PPA?

A (Bowman) Yes.

Q Okay. Thank you. Would you agree generally that PURPA and the related FERC regulations have a principle of nondiscrimination against QFs?

A Yes.

Q Would you also agree that this is not an absolute bar to distinct treatment among QFs?

A Yes.

Q Do you know the standard to be one of undue discrimination?

A What do you mean by "undue discrimination"?

Q So to justify distinct treatment among QFs, you would need to show that there's some justification, there's some basis in fact for treating them differently.

A I think you would need to distinguish why there was different treatment, but I believe that PURPA affords different treatment for different types of technologies and different locations, so I believe that there exists the ability to differentiate.

Q Okay. First, do you agree with me that introducing a new category of cost and negotiated PPA could cause some consternation and generate a new area of controversy with developers?

A I -- I don't -- I mean --

MS. FENTRESS: I'm going to object. That causes her to speculate on what developers might be thinking.

CHAIRMAN FINLEY: Overruled.

A I'm not -- not necessarily aware.

Q Okay. Second, does the Company at this time provide any evidence to justify the inclusion of cost in negotiating -- in negotiation contracts, but not in standard offer contracts?

A So I believe Witness Snider touches on this. I think at this time we haven't proposed any specifics, but I'll defer to Mr. Snider.

A (Snider) Certainly. The standard offer contract, remember, is not a solar contract. It is a general QF contract. The way in which it's constructed in North Carolina assumes that there's an equal 100 megawatts of generation around the clock available in every hour. That's how rates are developed. That's how capacity and energy rates are developed. And that is not a technology specific application, so we are not including in the technology agnostic general offer rate any ancillary services.

I think what we touch on is that when you take into account the unique characteristics of a specific QF that is not an equal 100 megawatts around the clock, it may be appropriate in the larger QFs above the standard offer rate to take the specific characteristics, as Mr. Holeman pointed out in great detail yesterday, into account in that process. So, no, we are not offering them in the standard rate, which is technology agnostic, because there is no specific ramping or ancillary needs that we point out in that rate. Again, there's a big difference between our standard offer rate and a technology specific rate for above 1 megawatt.

Q Thank you for that answer, Mr. Snider. I recall you testifying on potential integration cost being a decrement to the standard offer of what it cost in the Sub 140, but you did not propose it at that time. Do you recall that?

A I believe in Sub 140 we did propose to have a -- an ancillary service charge at the standard offer which we then ultimately did not include as it was a generic rate. And now we're saying that if you were to take the specific characteristics outside of the standard offer into account, that would be the appropriate time to look at the potential for what those specific characteristics drive you to spend, not within -- and we're not proposing it in the 1 megawatt and under technology agnostic rate. It's just a plain QF rate for co-gens, for solar, for biomass, so it's not in our -- our standard offer. We're saying it is appropriate to consider that outside of the standard offer.

Q Okay. Thank you. And would you agree for that decrement to apply to the standard offer, you'd be looking at costs that apply to the fleet? It wouldn't just be a QF specific cost, that there are -- there are some costs that have been contemplated as being a decrement that would be attributable to the whole fleet of QFs?

A It would be a cost that the technology specific

QF, whether the individual or a group of them, would impose upon the system.

Q Okay. Thank you. And to this point has Duke developed a method for calculating those types of costs for specific QFs?

A I don't believe we're proposing that within this standard offer rate. We do mention outside of this proceeding that we have done studies that look at the cost of integrating specific technologies and that those studies continue to evolve.

Q Okay. Thank you very much for your answers, Mr. Snider. I think we're going to move on to another topic here. So we're going to talk about the competitive procurement process, and I will try not to duplicate anything done yesterday.

Ms. Bowman, you testified yesterday regarding the competitive solicitation process so I'll try not to duplicate that. If we could look at page 10, lines 9 through 12 of your rebuttal. And I'll give you a second. If you could let me know when you're there.

A (Bowman) I am there.

Q Okay. Thank you. And so on that page you state that, "...the Companies' proposal to collaborate with interested parties to develop a competitive solicitation process to provide for sustainable growth in new solar resources..." Did I get that right?

A You did.

Q Okay. Thank you. So is Duke currently engaged in any form of collaboration with the solar industry to develop a competitive solicitation proposal?

A So I -- I will say that we have been working with a group of stakeholders since last fall on a host of issues related to energy policy and renewables in the state of North Carolina, and that includes solar developers.

Q Okay. So that -- that was last fall. Is there anything currently underway?

A There is currently a stakeholder group working on energy policy over at the North Carolina General Assembly. That's currently going on at the moment. And we are continually working with stakeholders.

Q Okay. Thank you. And have the Companies reached out to parties to begin development of specific parameters of what a solicitation process would entail?

A I believe in those negotiations we have talked some about what a competitive solicitation proposal would entail, and I also listed out some parameters on the last page of my direct testimony.

Q Okay. Thank you. And can you -- can you describe the types of parties that the Company has been engaged in this collaboration with?

A So there's a whole host of parties from solar developers, swine and poultry, biomass. I believe some wind has been involved. We have our large industrial customers involved. We have electric co-ops and munis. All of those interested parties and impacted parties to energy policy in the state of North Carolina have been involved.

Q Okay. And would you -- would you say that any progress is being made at this time on advancing that proposal?

A I have no idea what you mean by -- by "progress." We are in discussions. I cannot prog--- prognosticate on any outcomes from the General Assembly.

Q Okay. Thank you on that. I'll accept that. And do you -- do you have any current plans to seek additional input from the stakeholders?

A As we have said in my -- as I have said in my direct testimony and as we mentioned in our initial filing, you know, we are requesting, you know, a separate proceeding to work with stakeholders and collaborate on the development of a competitive solicitation process for

North Carolina.

Q All right. Thank you very much, Ms. Bowman.

Mr. Freeman, I'd like to turn to you and switch to another -- another topic. Let's talk about legally enforceable obligations. So you've testified that it's important for QFs to make a meaningful and binding commitment to sell their output to the utility before establishing a LEO. Is that an accurate description of your testimony?

A (Freeman) Yes.

Q Okay. And according to the Company, one reason for this is to prevent small QFs from having the option of locking in avoided cost rates, but also being able to back out of a commitment to sell if those avoided cost rates rise; is that correct?

A I don't think I differentiated small versus large, but generally, yes, the answer is correct.

Q Okay. Thank you.

A Or your question is correct.

Q Thank you. And is it your position that there's also no harm -- harm to the utility if the QF that has made that commitment to sell can back out of the commitment without any consequence?

A Ask your question again, please.

Q Okay. Is it your position that there's also no harm to the utility if a QF that has made a commitment to sell can back out of that commitment without any consequence?

A I don't think I'm saying that at all. I think there -- there is harm if you back out of that commitment.

Q And what is the nature of that harm?

A Well, it goes to, you know, the whole idea of establishing this commitment, you know, through -- through the current LEO process, I mean, the retail customer or our customers are committed to accept the, you know, the energy from this commitment. We've got to plan on, you know, these commitments as part of our resource planning. You know, we're purchasing both capacity and energy, and not having any idea whether a commitment is -- is binding or not has an impact on, you know, our, you know, fuel and capacity planning going forward.

Q Okay. Thanks. So it's also the Companies' position that larger QFs need to make a bonafide commitment to sell before they can establish a LEO; is that correct?

A Yes.

Q And in the context of negotiated PPAs, doesn't the Company generally require substantial liquidated damages if the contract is terminated because of the QF's inability to -- to deliver power?

A Well, define what you mean by "substantial."

Q Okay. Well, maybe we can just say doesn't the Company generally require liquidated damages --

A Yes.

Q -- in that circumstance?

A Yes.

Q Thank you. And in these -- in --

A And those -- I mean, those damages are designed to protect the customer, like I said, from, you know, the -- the QF being able to walk away from that -- that project.

Q And so in these negotiated PPAs, a QF that achieves commercial operation late must also pay these penalties; is that also correct?

A That is correct.

Q And is it your understanding that liquidated damages are supposed to approximate the harm suffered by a party in the event of a breach of contract?

A Yes.

Q And what's the nature of the harm to the

Company that these provisions are supposed to prevent -- represent?

A Well, again, the -- the LD damage calculation is based on the capacity component, and it's generally being derived from a one-year value of that capacity and -- and the utility needing to potentially go to the market and replace that capacity in -- you know, from another resource.

Q And so would -- would you say that's true even if the late operation is achieved in a year when Duke claims it has no need for additional capacity?

A Yes.

Q And when is solar -- when does Duke begin to rely on QF capacity and energy in the IRP process? Let me just ask that.

A I think I would need to defer that question to Mr. Snider.

A (Snider) Again, our first capacity need, as stated earlier in my testimony, is 2022 for DEP, 2023 for DEC. I believe we'll have discussions throughout this day talking about how the QF is being compensated for capacity starting at that point in time at a level that is in excess of what the IRP values that QF at, but under the standard rates today and under the way we -- we do it under Schedule B, we give them credit for deferring capacity. Starting in that first year of capacity need we credit them. Solar in particular gets about 40 percent of a peaker. In other words, for every 100 megawatts of the solar that comes on, we're crediting them with 40 megawatts of capacity deferral largely based on the -- the Schedule B hours that are in existence today.

This gets into my testimony on the difference between the QF process and the IRP process where in truth, solar will not be avoiding capacity for the utility in the IRP, but the way the QF rates are structured today we still compensate them for avoiding capacity, so we have an avoided capacity component today in both our small QF and large QF for solar, even though as a planner, as you've heard from Dominion, as you've heard from Witness Holeman, is I'm telling you as a long-term planner, adding additional solar will not allow us to defer or avoid additional generation going forward, but we do pay for it. We're still paying for it under the QF rates.

So it starts in the year 2022 for DEP and the year 2023 for DEC, and that's our first year in need, and that's when we start compensating QFs for capacity.

Q Mr. Snider, just one -- one follow-up there. When do you include the QF in the actual model that's in the IRP? Is that when the QF comes online or when the -- I'm sorry -- the LEO is established?

A We don't go project by project, there's so many QFs in the queue. What we do is we say here's what's installed and existing today. Here's what we expect on a macro basis to come in going through time based on the thousands of QF in the queue and the estimates we get out of our regulated renewables group, and then we include the energy value that they provide immediately. So they're providing energy starting, you know, the day they come online or are projected to come online, and then it impacts our capacity starting in that first year of capacity need, as I explained in my previous response.

So we include them immediately and how they impact our energy needs. They can't defer any capacity if we don't have a capacity need, so they don't start to hit our capacity plan until the first year of need.

Q Okay. Thank you, Mr. Snider. Mr. Freeman, let's -- I want to switch topics. We're back in negotiated contracts here. Do you recall discussing yesterday that -- we were discussing terms and conditions. I believe counsel from SACE was -- was giving you some questions on that. And you stated that Duke wanted to remain free to modify the commonly included terms and conditions from time to time. Do you recall something to that effect?

A (Freeman) Yes.

Q And wasn't it your position yesterday that you did not want the Commission establishing standard terms and conditions for negotiated contracts because Duke and counterparties would lose some flexibility in their ability to negotiate?

A Yes. I did say that.

Q And does Duke currently present its so-called standardized terms and conditions on a take-it-or-leave-it basis?

A No. You know, I think we've even worked with your company on a number of projects, and we've evolved to what's -- what I would consider kind of a, "standard contract," but as time goes on, you know, we feel like there will be times we need to modify some of the terms and conditions of that contract.

Q Okay. Are there some terms that Duke will not negotiate that are off -- off limits?

A Yes.

Q And can you give any characterization of what

-- what those are, what types?

A Well, I would say that even avoided cost. I mean, we calculate what our avoided cost is and -- and, you know, it kind of is what it is. We've got security language in there. I mean, there -- there are a number of terms and conditions that we feel like are -- are set. And many of terms and conditions are very similar to what our standard contract terms are as well.

Q Okay. Thank you. Will Duke incorporate additional terms and conditions if a developer requests that they be included?

A I think we -- as you've seen with your company, I think we've been open to, you know, negotiations on -- on, you know, contract terms to this point.

Q Okay. And some discussion of the PPAs negotiated yesterday, so of the PPAs that were negotiated in 2016, did Duke make any significant modifications to terms and conditions based on negotiations with those QFs?

A I mean, define what you mean by "significant." I mean, that -- that contract has been in evolution over the last couple years to the point where it is today, to where we now have executed, as I think it was pointed out yesterday, roughly 20 some odd negotiated contracts.

Q Okay. I think I would characterize maybe as materially modified. Does that have significance to you?

A I'm not aware of what I would consider material modifications to that contract.

Q Okay. And are you aware that some states require standardization of contract terms for projects that are not eligible for a standard offer?

A I am not aware of that.

Q Okay. So you have not researched that issue particularly?

A Not particularly, no.

Q Thank you. And do you recall testifying yesterday that the Company has negotiated about a dozen nonstandard PPAs?

A Well, I think I just said a minute ago it was 20 plus, and I think, as I understand from the data request that we looked at yesterday, there were actually 22 contracts that were negotiated under PURPA, and then as I recall, there were an additional 10 or so projects that were negotiated under a -- a separate RFP. So there's been 30 plus contracts that have been negotiated that are above 5 megawatts, and they're all nonstandard contracts.

Q Right. But do you recall the conversation yesterday where I think you singled out there were 12 PPAs? Is there a particular time frame that that might be relevant to?

A I used the -- the 12 without looking at the data request, and that was just my recollection, so that was not an accurate number.

Q Okay. Thank you for that clarification, then. And can you -- can you answer when was the last time a nonstandard negotiated PPA for a solar project over 5 megawatts has been negotiated with Duke?

A I can't recall specifically. I know a -- a project as of yesterday was approved, a large project, that requires the signature of our CEO, and that project will be executed this week.

Q Okay. So that's one in -- have there been any others in 2017?

A I don't have the information to -- to answer your question.

Q Okay. I appreciate that. I think I'm going to move on to another topic here.

And Ms. Bowman, I'm back -- back to you, and would like to direct you to page 31 of your rebuttal testimony, and in particular lines 2 through 6, and I will -- let me know when you're there.

A (Bowman) Okay.

Q Okay. Great. So there you refer to the "...recent deviation in market-based commodity cost compared to prior forecast..." You say that results in more -- in customers paying more for electricity than the Companies' current forecast of avoided cost; is that correct?

A It results in customers being obligated for significant long-term overpayments compared to the Companies' current forecast of avoided costs.

Q Okay. And this deviation you're referring to, the primary -- is that, you know, primarily due to the lower than expected natural gas prices?

A Yes. And I believe Mr. Snider is the expert in this domain.

Q Right. And does that deviation also mean that the Companies' investment in, say, coal-fired generation has resulted in customers paying more for electricity than the Companies' current forecast on avoided cost?

A No, not necessarily. And I might defer to -- to Mr. Snider on this.

A (Snider) No. As -- as a matter of fact, you know, when you have dispatchable assets that can be dispatched based on real-time price signals, we -- we can then switch as needed. So if gas prices spike for a short period of time, we can burn coal and dispatch it in front of the gas. Conversely, if gas prices are low, we can dispatch the gas and dispatch coal later in the dispatch stack. It's this very abil--- this very exact dispatchability benefit that comes with dispatchable resources that are on different commodities that allow them to extract whatever value they have in real-time as opposed to a must-take where you're paying a fixed price no matter what into the future.

So I would not say that it -- just because gas prices have dropped, we don't have value or we've lost value in the coal plants. We can still dispatch those coal plants as needed and -- and so they're still -- still valuable on our fleet.

Q Mr. Snider, back -- I'm sorry. I'm going to move back to you here with this question. Do you agree that the overpayments that you discuss in your testimony are a result of the past projections of avoided cost being inaccurate?

A I would -- you know, again, I wouldn't say the past being inaccurate; I'd say the market moved. So, yes, the market was higher two years ago, it was higher than that four years ago, so if you go to Sub 136 and then to Sub 140, what we've seen is a continued decline in the market commodity prices for both gas and coal. And so when you're setting long-term prices based on an old market that was higher and the market comes in lower, you're wishing you hadn't gone out that far, so -- but it's -- it is the -- the plain matter of the fact is the commodity prices have dropped, and we've locked ourselves into substantial long-term obligations based on a time when commodity prices were higher.

Q Okay. And do you have any reason to think that the Companies' current projections of avoided cost in this proceeding are inaccurate?

A I think, very importantly, the Companies' projections in this proceeding demonstrate where the market is today. So we took great pains to go out and explain where the market is today, and that -- but to say that the market won't move two years from now -- could go down again, might go up, but we went through an extensive process to show why it's important to use the market price as opposed to a spot forecast, why -- and we'll get into that, I'm sure, throughout the day -- but, no, I think today we've -- we've said here's what the current view is, and that's like any other market. It's, you know, here's where we're at today, and we think these are just and reasonable rates at today's market conditions.

Q Okay. And standing -- standing where you are today, you don't have any reason to think that these contracts entered into under the new rates would result in future overpayments?

A The longer term you go out, the longer the risk is. So whenever you go out in time, whether it's market forecast, whether it's fundamental forecast, there's a cone. Uncertainty gets greater through time, so no matter how we set rates today, the further we go out, the more risk there will be.

Q Would you also agree that there's -- it's an equal possibility that it might result in underpayments in the future?

A That's a great question. There's only an equal probability if you transact that market. If you adopt a fundamental price that's already above market, you are not at an equal probability. You are locking in a price that has a much greater probability that you will have overpayment risk. If you -- in the face of a liquid market where you can transact, you must transact at market to have that equal probability. If you transact at above market, you do not have equal probability.

So I would qualify my answer that if transacted at market, you do have an equal probability of going up and down. That's the definition of a market. So if done correctly, there would be an equal probability.

Q Okay. Thanks, Mr. Snider. And now, yeah, the mic can go to Ms. Bowman. I appreciate that.

So Ms. Bowman, I'm going to look at page 33 of your rebuttal, lines 10 through 12.

A (Bowman) Okay.

Q Okay. Thank you. And there you state that, "North Carolina's implementation of PURPA has significantly encouraged unprecedented QF development compared to other states."

A That is correct.

Q Okay. Thank you. Has there been any meaningful development of QFs in any other state in the Southeast?

A So I think we can go back and look at some of the charts in my direct testimony. So if you refer to page 36, Figure 7, of my direct testimony, it shows utility solar scale projects across the country, and you can see some there in South Carolina, Georgia, Alabama, Mississippi, Louisiana, and Florida.

Q Okay. And do you know if any of these states have more than 100 megawatts of QF --

A I --
Q -- solar QFs?
A I do not know that off the top of my head, but I would definitely say Georgia has more than that.
Q And are you certain that all the projects listed there are -- are necessarily QFs?
A Well, it depends -- I think they are technically considered a QF because they're a renewable energy facility, and if they're solar, they're deemed a QF under FERC. I think perhaps you're asking the question are those PURPA.
Q Uh-huh.
A Are they done under the context of a PURPA or avoided cost rate? And I believe there is another chart that we discussed yesterday in my direct testimony that -- where we talk about that in North Carolina we are 60 percent of all PURPA contracts in the country.
Q Uh-huh.
A And, you know, I -- I go on to explain the reason why, and that is because we have had long-term, fixed 15-year contracts for 5 megawatts at a, you know, fixed fairly high avoided cost rate, and so that is very attractive to solar development. And I believe that other jurisdictions in the Southeast, as I point out in

my testimony, do not have the length of the long-term contract, nor are they fixed for that length, and they're -- also, some of them are variable and the rates are lower.

Q Okay. So with that, isn't it the case in -- that, you know, North Carolina is the only state in the Southeast and one of the few in the country that has implemented PURPA in a way that has actually encouraged QFs?

A I wouldn't necessarily say that. I don't necessarily say that it's not -- it's the only state. I just said that we had, you know, unprecedented PURPA in North Carolina.

Q All right. Okay. Thank you. I'm going to my last topic here. I think we had a nice transition to contract tenor.

So, you know, as a general matter, would you agree that PPA length or tenor is an important consideration for any QF project developer?

A I believe, and I'm going to refer to my -- my testimony, my rebuttal testimony, that QF developers, you know, have to measure all sorts of things, price, contract tenor, cost of capital, risk of investment, amongst other things that come into play, debt and equity, how much capital they're putting into the project, those -- those types of things, so it's not the only thing. It's one thing that goes into consideration.

Q Okay. Would you agree it makes the first team of those factors?

A I am not a developer, nor am I a finance expert.

Q Okay. Thank you. Mr. Snider, let me ask you. This is based on page 11 of your rebuttal, lines 2 through 11, so I'll give you a minute.

A (Snider) I'm sorry. Can you repeat?

Q Yes, sir. That is page 11 of your rebuttal, lines 2 through 11.

A Yes.

Q Okay. Thank you. You explain there that the 10-year contract term is demonstrably financeable for a larger QF. I'm not quoting. I'm paraphrasing, to be clear.

A I think I say the 10-year term is demonstrated to be financeable, at least for larger QFs, as demonstrated by our experience.

Q Okay. And what is the basis of the -- that -- what is the basis of your conclusion? What is that experience you refer to?

A We have 10-year contracts in place here in North Carolina.

Q Okay. And just because some QFs have been able to finance a limited number of 10-year PPAs, does that prove that it's financeable for the broader QF community?

A No. I think I -- what I said is at least for larger QFs, it's been demonstrated that 10-year contracts are financeable.

Q And do you have a similar basis to conclude that 10-year contracts are financeable for small QFs?

A I did not support that in my testimony, so I'm not saying it's -- it is not financeable, and I'm not saying it is financeable.

Q Okay. Thank you. And did you hear Mr. Yates' testimony yesterday?

A I did.

Q Okay. And are you aware of whether Duke Energy Renewables has any projects with 10-year PPAs?

A I have no knowledge of the nonregulated side of our business and their -- what contracts they do or don't have.

Q Okay. Would you agree from the testimony yesterday that at least Duke Energy Renewables publicizes the terms of its projects on its website, or some of its projects?

A Yes. I'll stipulate --

MS. FENTRESS: I believe it's --

A -- to whatever is in there is -- is correct, what Mr. Yates said is -- is correct.

Q Okay. Thank you. And would you agree that PPA tenor is an important element for Duke Energy when it decides whether to develop or acquire a solar project that will sell its output to another utility?

A I'm sorry. Are you talking Duke Energy Renewables on the nonregulated side or are you talking about the regulated?

Q Yes. Duke Energy Renewables in that case.

A I'm --

MS. FENTRESS: I believe Mr. Snider has testified that he's not familiar with the nonregulated side of the house.

CHAIRMAN FINLEY: I think he can't --

A That is my --

CHAIRMAN FINLEY: I think he can't answer that question.

THE WITNESS: Yeah.

A So I'm not familiar with the regulated side of the house.

Q Okay. Let me ask you --

A The nonregulated side. Sorry. Sometimes...

Q Okay. Let me ask this in a general way, then. Does the PPA tenor affect the degree of risk associated with a QF developer?

A I think it's one factor, as Ms. Bowman said, and I find it interesting, you know, just anecdotally that what we're saying is we -- it affects their risk and what we'd like to do is put that risk on the consumer so that the QF can develop. Because risk has to go somewhere, so what we're saying in this docket, what I keep hearing is we need to transfer that risk away from the QF developer, put it on the consumer so that they can finance the project. And so, yes, it is a risk factor that needs to go somewhere, and what I'm hearing is the developer would like that risk to go to the consumer.

Q Well, for a developer, would you agree that not having contracted cash flows beyond the life of the PPA would create uncertainty about the return that would be realized on the investment?

A Yes. Having uncontracted cash flows over the life of an asset would create a degree of uncertainty. I do not read PURPA to say that you're supposed to take all uncertainty away from the QF developer.

Q Okay. One last real quick line of questioning. I appreciate your answers today. So Ms. Bowman, yesterday afternoon you answered some questions from SACE's counsel regarding whether the Company has done any studies or analysis to determine whether a 10-year PPA with a two-year reset on the energy rate would be financeable. Do you recall that?

A (Bowman) Yes, I do.

Q Okay. Just a very few follow-up questions here. So in preparing for this case, did the Company reach out to any QF developers to discuss the proposal and whether it would be workable for them?

A I believe I answered that question yesterday.

Q And could you refresh our memory? Was the answer no?

A Yes. If you look at my testimony, you know, I talk about I'm not -- I'm not a financing expert, you know, but we looked at other states, and we also looked at PURPA, and within the context of PURPA, it's up to the states to balance the needs of promoting QF resources and also ensuring that the rates are just and reasonable to the customer so the customers are not harmed. The QF PURPA put to the utility should not harm the customers. The intent of PURPA is to not harm the customers, and that's why they are entitled to the avoided cost rate, and there's lots of discretion left to the Commission. Our desire and our goal with reducing the term and in this avoided cost docket is to try to promote no harm and less risk to our customers of overpayment.

Q Okay. And does anyone in this Panel have experience developing a solar QF project and securing financing or equity investment?

A (Freeman) No.

A (Snider) No.

Q Okay. So is it fair to say that no one on the Panel --

CHAIRMAN FINLEY: The answer was a no. Go ahead.

MR. CULLEY: Okay. Thank you, Chairman.

Q So it is fair to say that none of you know whether a 10-year PPA for a 1 megawatt project or a 10-year PPA with a two-year reset provides a QF a reasonable opportunity to attract financing under the current -- current environment?

A (Freeman) No.

A (Bowman) No. No.

Q Okay.

MR. CULLEY: Thank you. That's all my

questions. I appreciate your time.

CHAIRMAN FINLEY: All right. Who's next?

MS. HARROD: Mr. Chairman, Jennifer Harrod on behalf of the North Carolina Attorney General for the Consuming and Using Public. Thank you, sir.

CROSS EXAMINATION BY MS. HARROD:

Q Mr. Snider, Ms. Bowman, Mr. Freeman, good morning.

A (Bowman) Good morning.

Q I -- I have no preference as to who answers these questions other than, you know, whoever -- whomever is most knowledgeable and most appropriate, so if I direct something to one of you, anybody can feel free to pick up the baton.

So Duke Energy in this proceeding is proposing to greatly increase the number of QFs that will need to enter into negotiated contracts as opposed to accepting the standard contract, and so I would like to have a better understanding of what the differences between those two things are. And I understand from Ms. Bowman's testimony that -- and I guess from Mr. Freeman's testimony, also, that at this point Duke Energy has a set of standard terms that it opens those negotiations for negotiated -- bilaterally negotiated contracts, correct?

A (Bowman) That is correct.

Q Okay. So for those -- those standard negotiated contract terms, how -- what are the primary differences in those terms as compared to the standard contracts?

A I would say the primary difference is for the large negotiated we do updated avoided cost rates, more real-time avoided cost rates, and the -- the standard are the avoided cost rates set in this type of proceeding.

A (Snider) And I'll just expand ever so briefly. The standard rates stay in effect for two years, no matter what happens to the market prices, and I've gone over a great deal of detail in my rebuttal and in my direct about how volatile prices can be. So when you go through the negotiated process, the real-time market conditions at least within that time period are being reflected, and you're not leaving a two-year stale rate available to a large number of QFs which presents a risk.

Q Okay. So the rate -- if I understand you correctly, the rate is derived using the ProSim modeling software; is that correct?

A Yes. The avoided energy rates are developed using the market prices of gas and coal at a point in time and how that would relate to avoided marginal cost as determined through the ProSim process in our rates department.

Q And it's the same inputs that would be used for establishing the rates in the biennial avoided cost proceedings?

A No. Actually, they're different inputs. So the inputs are coal and gas prices that you use at one point in time for the biennial avoided cost, and then those -- those rates get froze for two years.

So let me give you a simple example. If gas prices today were $4 across the curve, we would use $4 gas and say, okay, power is $35. If gas prices three months from now went to $3, we would run ProSim with $3 and say the then negotiated rate is only worth $28 to the utility in equivalent power, whereas if they were under the standard rate, you would not get to reflect the fact that gas prices have dropped, and they would still get the standard rate back from the original filing. So as we move through time, ProSim is using new market data to give you the value of marginal energy.

Q Okay. So let me clarify my question. The value of the inputs will change over time as the market changes, but the actual inputs themselves, you know, for instance, if it's the price of gas, that's being -- that

that value will change, but what you use, what Duke uses as the price of gas is the -- is the same as it would be for a standard contract and a negotiated contract?

A Right. So what we're saying is it's the same system; it's just a new gas price getting put into that system.

Q Okay. So just to make sure I'm clear, at the present time, the negotiated contracts do not have a factor in them for the cost of integration?

A (Freeman) No, they do not.

Q Okay. And the proposal is that in the future they may -- they may have that term.

A We haven't made a formal proposal, but, yes, that is our plan as time goes on to include integration cost in -- in those contract prices.

Q Are there any other plans to deviate between the pricing -- the way pricing is calculated for a standard contract and the way pricing is calculated for a negotiated contract?

A (Snider) You know, I think what we've talked about and what you'll probably hear more about today is the value of a technology specific. Again, the rates, as filed in this proceeding, are technology agnostic, so they assume that there is an equal amount of generation from some generic QF in every hour of every day, and then you average those values to come up with both energy and capacity. So when you look at -- and that has a long history back predominantly to baseload generators such as qualifying facilities that burned some fuel and then produced steam, and so you had large QFs that burned gas that were largely baseload, and that's how a lot of our policies came into practice today.

So when you then take and move from that generic rate to a solar-specific rate, as would be envisioned under PURPA, you take into account what are the attributes of that specific technology. So when we looked at it, said there are different ancillary service costs or integration costs with that technology specific as opposed to just this generic rate.

There are other things that are different as well, so as we've spoken about today, capacity and how much capacity can the utility actually not build from a generic QF is very different than how much capacity could I not build from a solar QF. So the rates, as applied today, pay -- still pay a fairly handsome capacity payment even though very little capacity can be avoided through solar.

So I do think we need to take into account when looking at a technology-specific rate how much capacity value is actually being avoided by the utility so that we're not paying QFs for capacity that's not being avoided. And so as Ms. Bowman pointed out, what is just and reasonable for the consuming public is a -- is a big concern. So I think when you get into a technology-specific rate, that's another area that will need to be addressed for the large negotiated and potentially in the future if we did have a standard technology-specific rate in the standard offer. We do not propose one at this time.

Q Okay. Before you give up the microphone, is the Company considering -- you know, there's quite a bit in Duke Energy's testimony about the uncontrolled nature of solar development. Is the Company studying paying higher rates for things like locations that are more advantageous on the grid or the kinds of power quality services that Ms. Harkrader testifies about? Is that being studied?

A (Bowman) So I will comment that that's one of the reasons we are talking about promoting a competitive procurement process that would be outside the confines of PURPA. If you look at my direct testimony on page 60, I believe I've -- I've referenced this numerous times. In that competitive procurement process outside the context of PURPA we would be negotiating with intermittent renewable resources, and DEC and DEP would have the ability to site in those locations that would be good for the grid on the system. We would also have the ability to curtail and dispatch those. We would agree to potentially longer contract length terms as an incentive to get those good locations and the ability to curtail and dispatch. So we are definitely looking into that, and that's why we have proposed this different model for solar development.

As we talked a little bit earlier about the development in other Southeastern states, they've done that outside, and other jurisdictions in the country have done that outside the confines of the PURPA put. They've done it in a different way, and that's what we're proposing to do here in North Carolina, a smarter, more sustainable managed way.

Q So Ms. Bowman, operationally, what I'm hearing you say is that it is possible for Duke to pay more higher rates or offer otherwise more favorable terms to get -- to get power from the QFs that is more usable to it, correct?

A (Snider) Exactly. So I would say -- you know, you asked earlier about ancillary service costs or, you know, integration costs. There would be a different integration cost for a controllable QF than a non-controllable QF. So it -- it still may have some integration costs. You still can't -- when we say control, I want to be very clear, it's not dispatchable. It's controllable. I can't call on a unit if the sun is not shining or if there's a cloud overhead, but if I can control it to the extent it does have output capability, that reduces the -- the ramp and the ancillary needs that Mr. Holeman spoke about yesterday.

So clearly in a situation where you had controllability, as proposed by Ms. Bowman in a competitive solicitation process, that would be part of the competitive solicitation, would be to ensure controllability, you would be able to offer them a rate that didn't include a decrement to the extent the -- you know, to the level of the decrement that's needed for non-controllable. So there would clearly be differentiation between the QF technologies depending upon those characteristics.

Q Okay. So it's -- it's operationally possible to do that. My question is why -- or is it possible to do that under PURPA as opposed to through an RFP process?

A I guess all of us could have answered that. PURPA, to I think all of our reading, only allows the most limited control in system emergency. So PURPA, by its very nature, is a you must take, you -- you know, that is sort of one of the underlying, it's got to be a just and reasonable rates, but you must take. You cannot economically control. You cannot do what's in the general best interest of the system operator. You have to limit yourself to controllability by PURPA under, you know, the most stringent definition of system emergency. Having controllability allows you to do what's in the best interest of the customer to reduce those ancillary service costs and, therefore, that is where you could offer the different rates.

So, no, you cannot -- you cannot mandate under PURPA what you could ask for in a competitive solicitation process. And I'll turn it over to my Panel, if they...

A (Freeman) Well, I'll just reflect a little bit on some of the things that we're -- we're experiencing today. You know, under PURPA, a QF is entitled to our avoided cost rate. It's a generic avoided cost rate regardless of where that project is located on the system. So we've got examples where one particular QF has no upgrade cost, you know, associated with that project, and a project elsewhere on the system may have significant upgrade cost. And depending on, you know, the -- I'll call it the staleness of the avoided cost rate, you know, that QF may or may not be able to afford a significant upgrade cost.

So we have one example that I use quite often where a particular project locked into a -- a very old avoided cost rate located on the system where it cost the developer $2.3 million to upgrade our system to accommodate that project. Under that same rate, another project located in a different location had no upgrade cost on that -- you know, to accommodate that project. So what we're trying to move to with this competitive solicitation process is move to a process where the developer provides us a price that's separate from avoided cost that reflects their investment cost plus, you know, a fair return on their investment, and then we will look at, you know, where those projects are located on the system in making determinations as to which projects make the most sense to bring on the system.

Q And, again, so that's not talking about refusing power. That's just talking about where something is located on the system. Would it be your understanding that PURPA would not allow differentiation for rates for, for instance, a placement on the grid that might result in -- in less line loss?

MS. FENTRESS: I'm going to object. This line of questioning is asking these witnesses for technical legal interpretations of PURPA's requirements, and they are not testifying as attorneys.

CHAIRMAN FINLEY: Oh, yes, they are as to legal requirements of PURPA. Overruled.

A (Freeman) I mean, ask your question again.

Q Sure. I understood what you said about -- about the fact that you can't curtail power outside of the emergency context, so my question was about whether it would be -- whether your understanding under -- acknowledging that you're not lawyers, whether it's your understanding that PURPA would allow for differentiation of rates based on whether a QF was located on the grid in a more advantageous location, for instance, where it would result in fewer or no line loss?

A (Bowman) I'm not sure about your reference to specifically line -- line losses. You know, the way we are setting QF rates for the standard contract in North Carolina is not based and it's not related to the cost of the PURPA project. It is related to the utility's avoided cost. So I think that's one differentation (sic).

PURPA does allow for differences in rates for technologies. You can take that into account. You can take into account the dispatchability. Is the asset dispatchable? You can take into account those things. So could -- and I believe we acknowledge that you could come up with a separate rate for solar, and I believe we've talked about coming up with something separate for the negotiated, taking into context certain things in that, so I believe technically PURPA allows for -- for differentation (sic), but to get to where we need to go from an operational standpoint and looking at the risk of cost to our customers, we want to promote something outside the context of PURPA because we believe that provides the greatest flexibility, and that is the best way to move forward in this state for the development of -- of solar and renewables.

Q Okay. Thank you. Quick question about negotiated contracts. Do the -- does Duke Energy negotiate on any non-price terms on a -- commonly with those negotiated bilateral contracts?

MR. BREITSCHWERDT: Objection. This has been asked and answered. We spent five minutes with Cypress

Creek's attorney talking about non-price terms that were negotiated.

CHAIRMAN FINLEY: Well, let her ask it again. Overruled.

A (Bowman) Yes, we do. Gary?

A (Freeman) I think the answer is yes. We've -- you know, we've evolved or iterated the nonstandard contract over time as part of the negotiation process with -- with these developers.

Q Okay. So is the -- the length of the term, is that a negotiated -- is that a term that Duke will negotiate?

A No. No, we have not.

Q You're sticking to 10 years; is that correct?

A Well, we had been sticking to 10 years up until recently, but, you know, now that negotiated rate for a nonstandard contract is five years. And we -- we look at that, you know, that term, you know, based on what we feel is just and reasonable for our, you know, utility customers. And I think Mr. Snider has touched on this multiple times, the -- you know, the further out we go with that term, the more uncertainty with that -- that pricing.

Q Mr. Snider, I want to ask you a few questions, and I -- I do recognize that you testified at some length yesterday about the approximately 1 billion in overpayments for energy and capacity relevant -- relative to current market, and I'm quoting from your direct testimony at page 38, line 1 through 5. I -- I have a couple --

A (Snider) I'm sorry. Can I just get to that page --

Q Of course.

A -- page 38?

Q Of course.

MS. HARROD: For the comfort of everybody in the room, I have a couple of questions that I don't believe he testified to.

A Okay. I'm there.

Q Okay. Thanks. So what I wanted to know is, is when you're -- when you testified or when you -- when you developed that number, I want to understand, is that an apples-to-apples comparison over the rates that were established in the Sub 140 docket? I notice that in Dr. Johnson's filed testimony, he testified that he understood that you arrived at that figure by taking a snapshot of a single year, 2015?

A Yes.

Q Is he incorrect or correct in that?

A He was very incorrect.

Q Okay. So when you came up with that number of that 1 billion in overpayments, what I'd like to know is when you looked at the -- the gas pricing for the Sub 140 and your calculation that there were a billion dollars in overpayments, did you use the same -- did you use the same term -- I understand that the value is different, but did you use the same term in terms of using the five-year forward prices and then thereafter the fundamental forecast developed by Duke?

A No. We -- as I explain in great detail in my testimony, we've used in our 2015 IRP, our 2016 IRP, and in this proceeding, we use 10 years of market prices for gas. We've secured gas, bought gas for the utility for 10 years out. So consistent with our last two regulatory filings, consistent with this filing in this case, and consistent with our experience of purchasing gas, I did use the long dated. So I didn't use 2015 or 2016 gas and then compared it to a long-dated obligation. I used the gas price that was commensurate with that obligation, so here's the market price for gas over the next 10 years, here's what the utility could produce power for today at today's market prices, and then here's what we're paying

QFs under the old rates over that equivalent term structure.

So I used the same term and matched up a market obligation with a market obligation, so we have a forward obligation, we have a contractual obligation with these QFs that is no longer negotiable. Those prices are set, those terms are set, and we will pay that to those QFs over the next 10, 11, 12, 13 years remaining in those contracts. That was a $2.9 billion obligation just for what was in effect at the end of last year. If I reprice those today using the current 10-year plus term for gas, those would be worth 1.9 billion. So I did use a very apples-to-apples comparison.

Q Okay. And just to be clear, the price that you used for current forecasts where you said there was a $1 billion overpayment, was that 2017 pricing?

A That was pricing actually as of what we did in -- we filed the rate. So I didn't even take into account -- the 1 billion would actually be greater, it would be much bigger than a billion if I included the drop in fuel prices that we've seen since we filed these rates. So the 1 billion was only back to where fuel prices were when we filed these rates as of November 15th, and today fuel prices have fallen even further, and I demonstrate that in my testimony, that fuel prices have dropped, you know, somewhat significantly over the 10-year term since we filed the rates. So back in November the rates that we used to file this fuel was higher. I used those, so it's consistent with --

Q Got it.

A -- the rates filed in this proceeding.

Q Okay. And I don't want to quibble with you about what apples to apples means, but -- but I just want to make it clear that in coming up with the $1 billion shortfall, you did not use the methodology that was approved by the Commission in the Sub 140?

A No. That's incorrect. The Commission in 140 did not mandate -- actually, what they mandated was use what was in your most recent IRP in 140. In 140 we had five and -- five years of gas prices and a blend -- or actually a jump right to fundamentals in the IRP, and so we were ordered to use what was in the IRP, and we did do that in 140 subsequently and filed rates. We have filed two IRPs since then with 10 years of market prices, and consistent with that Order, we have used market prices in this proceeding that were consistent with those used in the IRP. So I believe I'm being very consistent with what was explicitly told to do in the Order in 140.

Q Okay. Thank you for clarifying that. Mr. Snider, in FERC's Order Number 69 it says, "In the long run, overestimations and underestimations of avoided cost will balance out." We're talking about a change in the forecasting in a two-year period of time. Do you believe that that constitutes in the long run for -- to give overestimations and underestimations a chance to balance out?

A I'm sorry. Could you rephrase that? I -- I don't know what you're asking me to compare when you say two-year time. Try rephrasing.

Q Okay.

A I'm sorry.

Q Sure. Absolutely. No problem. So I understand that the -- that the tariffs that were developed in the Sub 140 occurred according to what's happened to gas prices since then turned out to have been too high based on -- based on what happened with the market over the last two years, correct?

A Yes.

Q I guess what I'm asking you is, the model that FERC favors is allowing there to be a longer -- "a long run" is the term used for those overestimations and underestimations to balance out, and I'm asking you do you think that two years is sufficiently long to allow those overestimations and underestimations to balance out?

A I think -- I don't believe that's the proper interpretation of their Order. I think when they say over and underestimations will balance out, it means if you were to consistently be able to buy power at the then prevailing market prices. So if I every month could have an avoided cost rate, if we had this proceeding every month, God help me, you know, and set a new avoided price rate every month, that over time, if you had an existing amount of QFs, let's say 100 megawatts of QFs took service in month one, month two, month three, that if you looked across time, some of those would be overpaid and some of those would be underpaid. And so if you had updated rates very regularly and you had consistent PURPA development very regularly, it would be almost like a hedging program.

It's like your stock market. You're putting money in your 401(k), and some weeks you're like, boy, why did I put it in there, the market has come down 20 percent; other weeks, boy, it went up 20 percent, I'm glad I put some in there. If I do it across time, the over/under balances are going to even out. That's what they were referring to in that Order. And what we're talking about here is moving to a method that does allow a larger percentage to be priced on a more regular basis so that you don't allow a systemic risk of having a large number of QFs come in and at the cost of the consumers of North Carolina, to the benefit of the QF community, come in and get a rate that's known to be stale and over market. And that's what's happened.

We saw that right before we filed our new rates. The QF community noticed that, hey, commodity prices are coming down. We had over 300 megawatts in that last month establish LEOs, say I better get my rights to these high, no-longer justified prices in place so that I can take advantage of the process that's currently in place in North Carolina. And -- and so, no, I don't think you've properly interpreted PURPA at all, and I think it's -- it's certainly meant to do exactly what we're doing, which is to update these rates more often so that over and under can balance out.

Q Thank you, Mr. Snider. So -- but let me -- let me -- I think I understand where you're coming from. Let me just -- you said that if a market rate -- if a contract is made at a market rate, then both parties entering into that contract at the market rate share the risk of over and under estimations, correct?

A Very clearly, if done at a market rate when there is a liquid available market, you must transact at that market and not at something higher than that. So if done at a transactable market that's liquid and demonstratable, then yes, through time, you know, when that market moves up and down, it can go up or down. One of the systemic risks we face, though, is unlike our stock example where we're going to invest every two weeks, what happens in the QF world is the market moves up and down, and as soon as price level is high enough, I'll come in. When price levels go down, I don't have an obligation to come in. So I'm not investing every two weeks in my 401(k); I'm investing only when prices are high and not when they're low. And that's -- you know, that's the systemic risk that you face with QFs, is they don't have an obligation to sell to you when prices are low, but they have the right to sell to you when prices are high.

Q With that being said, would you say that the biggest distortion in the current system that we have is the staleness issue that Mr. Freeman has testified about?

A That is one. It is a big issue. Probably the largest issue is, in my opinion, the use of anything other than a demonstratable gas curve that's liquid to set that long-term rate if you're going to go into the long term. We talk a lot about the payment of a PAF, which I'm sure we'll get into more, which oversubsidizes capacity, and then probably the use of a technology specific rate as opposed to a rate that's being generated off the assumption that there's going to be 100 megawatts of generation in each and every hour that is net dependable capacity in every hour. That's how our generic rates are set. So I do think that you need to move to technology specific rates that recognize the difference between a baseload QF that's providing steam and burning gas is a very different QF than a solar QF or a wind or a biomass, so technology specific is -- is another one. So there's many factors that we've talked about this proceeding.

Q Okay. But to be clear, the one that you mentioned last, the technology specific rate, is not at issue in this proceeding?

A No, it's not.

Q Okay.

A We've pointed out the differences.

Q Okay. Yes, you did. All right. I think I just have one more short line of questioning. In Ms.

Harkrader's testimony -- Mr. Freeman, are you familiar with that?

A (Freeman) Yes.

Q Okay. She mentioned that the QFs had agreed to penalties for not abiding by time frames required by the interconnected -- interconnection standard. And she also offered her opinion that the long delays between the establishment of a LEO and interconnection to the grid are caused by the long times that it takes for the utility to -- to engage in the study process and not by the QFs. And I understand that the -- that you -- that Duke Energy is going to propose some contracting procedures to try to streamline that timeline. Is the -- are the Companies willing to impose timeline requirements -- time limit requirements on themselves that have teeth to keep the -- to keep the Companies also on track?

A Well, we are doing all we can within reason to comply with -- with those contracting timelines. I think I testified yesterday that we continue to add a tremendous number of resources to try and meet those timelines. But you mentioned Ms. Harkrader's testimony where they've got, you know, penalties. I want to kind of elaborate on that a little bit.

I mean, we do have -- I would call it a penalty or an obligation, that we've got to study these projects in a very nondiscriminatory way. We cannot discriminate, so, you know, each project is, you know, kind of looked at in that fashion.

But even more importantly in my mind is that we have the obligation to ensure that we maintain system reliability and service quality for all of our customers, and to do that, you know, there's this -- this I'll call it balancer or relationship between speed and accuracy. And, you know, we've seen several times now where sometimes, you know, speed is not maybe the most prudent way of looking at these projects and the impact that they have on the system.

So in my mind, you know, this reliability, service quality obligation, and if we fail to maintain, you know, that obligation, that could have a much, much more significant financial credibility, you know, issue on the Company than any kind of financial penalty that you might imply that you -- you know, as -- as part of that process.

Q Okay.

MS. HARROD: I thank you all, each one of you, for your attention and your answers. Mr. Chairman.

CHAIRMAN FINLEY: Okay.

CROSS EXAMINATION BY MR. DODGE:

Q All right. Good morning, Panelists.

A (Bowman) Good morning.

Q Most of my questions are probably going to be primarily directed at Mr. Snider, but I do have a few for Ms. Bowman as well that I'd like to -- to start with.

Ms. Bowman, in -- in your testimony and in your summary you listed a number of changes throughout. I can give you some specific page numbers, but just the changes that DEC had recommended as a result of the growing concern of the volume of QF development in North Carolina.

A Uh-huh.

Q Do you agree that the Public Staff's position in this reflects -- this proceeding reflects some of those same concerns?

A I do. They do reflect some of those very same concerns.

Q And would you also agree the Public Staff's position in this proceeding reflects a change from prior -- from its position in prior avoided cost proceedings, recognizing those concerns such as our agreement with the Utilities' proposed reduction in standard contract eligibility thresholds from -- from 5 megawatts to 1 megawatt?

A Yes.

Q And, similarly, the reduction of the maximum standard contract from 15 years to 10 years?

A Correct.

Q Okay. So these adjustments to the standard offer thresholds will result in a larger percentage of facilities that have to utilize nonstandard negotiated contracts with the Utilities, and that the use of those nonstandard negotiated contracts and the updated information that flows into those discussions will -- should help reduce some of the stale rate concerns that are raised by the Utilities?

A Yes. I think I make a mention to that effect in my testimony --

Q And --

A -- my rebuttal.

Q And also reduce the risk of ratepayer risk, as Mr. Snider has alluded to, the forecast risk and term risk associated with those -- those longer term contracts.

In addition, the Public Staff supported the Utilities' position on some steps needed to address the operational challenges faced by the growing amount of solar generation particularly in North Carolina?

A Yes.

Q And Mr. Holeman spoke about this a little bit yesterday, but you, in your testimony, did have a discussion about some changes to the standard contract provisions related to imminent emergencies. This is on page 54 of your direct --

A Yes.

Q -- testimony?

A And the curtailment, uh-huh.

Q Yes. And Duke is requesting that a contract provision be added, stating that an imminent violation of NERC BAL standard constitutes a system emergency?

A That's correct.

Q Would -- would you agree that Duke already has the ability to curtail QFs during a system emergency under PURPA?

A Yes. I believe it -- it does, and PURPA does provide for the curtailment in system emergencies. But I believe that, as Mr. Holeman testified yesterday, the definition of emergency is -- is fairly loose, and thus far it's been a very high hurdle. You -- you have to be in a really dire situation before declaring that emergency, so we're proposing some changes. It doesn't completely resolve the operational issues, but certainly adding those provisions that if you're going to violate a BAL standard does help.

Q All right. And so if the Commission determines that an imminent violation of a NERC BAL standard would constitute a system emergency, then the -- the language in the current contract would be sufficient to allow the Utility to make curtailments during those circumstances?

A During those circumstances, correct.

Q Okay. Thank you. And switching subjects a little bit, in your rebuttal testimony you provide an alternative proposal for making fixed energy rates available to -- for standard offer QFs for 10 years?

A Correct.

Q And you and Mr. Snider discussed this a bit yesterday. I believe Mr. Snider characterized the resulting rates that would occur under that calculation of rates as being slightly loader -- excuse me -- slightly lower than a calculated 10-year rate would be. Do you recall that discussion, Mr. Snider?

A (Snider) Yes, I do.

Q And Mr. Snider, I think you indicated that the hydro rates would provide a basis for comparison since they are calculated on a 10-year basis; is that correct?

A Yes. And I -- I think I qualified it with, you know, they're slightly lower if you're using the market curve as we proposed in the hydro rates.

Q Okay. Do you have your direct testimony with you?

A I do.

Q If you could turn to page 8 of your direct testimony. I'm going to refer to Figure 1 here in -- in your testimony. I know it's kind of fine print on this page, so I'll read out the numbers.

A We'll fix that next time.

Q So in your -- we'll just focus on the top with Duke Energy Carolinas. I'm just trying to kind of better understand what the -- the two proposals, the current two-year rate would look like as compared to the 10-year alternative proposal fixed -- fixed alternative proposal that the Utility is offering. I'm looking at the -- the top row, Duke Energy Carolinas, for the energy credits. And under the Option B, Other PP box, you indicate the on-peak rates would be -- for the variable rates, this is for the variable rates, 3.59 cents per kWh; is that correct?

A I see that, yes.

Q And the off-peak would be 3.16 cents per kWh?

A I see that.

Q Okay. And then if we go to down to the 10-year fixed long-term rates in that same column for Option B, the on-peak and off-peak energy credits are the same; is that correct?

A Correct.

Q And that's based -- those would -- under the Utilities' proposal in your direct testimony, those would be reset every two years, so those rates would not necessarily be the energy rates that they would get following the next biennial proceeding?

A Right. They would be updated with each biennial proceeding.

Q Okay. Thank you. So now let's go over to the hydro column, so I'm looking at Option B Hydro - No Storage, the last column.

A I see those.

Q All right. The energy credits for the variable rates for the hydro are the same as they are for the Other PP; is that correct?

A Correct.

Q For both on-peak and off-peak. All right. Now, if you go down to the 10-year fixed long-term rate for the hydro, the rate is different here.

A Correct.

Q For the energy credit for the on-peak it's 4.06 cents per kWh and for the off-peak it's 3.42 cents per kWh; is that correct?

A That is correct.

Q All right. And just to make sure I understand the difference -- well, first let me -- let me ask a point. Under the Utilities' proposal, the fixed rates that would be fixed for 10 -- you would take the two-year rates, which are the initial rates we talked about, the 3.59 cents and the 3.16, and fix those for 10 years and carry those forward for the term?

A I think just one distinction is it would be at the QF's discretion, so they could choose to take the two-year rate and fix it for 10 years, or they could choose to take the two-year rate and if they had a view that the market was going to be more favorable in the future, they could elect to have that rate then get reset. So with that stipulation, yes.

Q Okay. And the Public Staff didn't agree with the two-year reset, if you recall that from our testimony?

A I do recall.

Q And so under the Public Staff's calculation, those 10-year rates would have to be based on a 10-year ProSim model run more similar to those rates for the hydroelectric facilities?

A Well, I guess that's one of my -- my larger concerns in this proceeding, is that they may not be consistent with that because Public Staff also took the position that rather than using the actual market price of gas, that we should use a fundamental forecast which would then raise both the hydro rate for the 10-year fixed and raise the non-hydro rate fixed price to levels above market. That's one of my larger concerns.

And so by going to the two-year and just extending it as a alternate compromise, you eliminate that debate of which fundamental forecast do you use and market and liquidity and a lot of things we'll speak more about today, but it -- it says QF you can choose between the two at your discretion, and then -- so that's -- that is one of my big concerns is, no, it wouldn't necessary lock in those hydro rates.

Q Okay. And I agree with your -- your statement there that there is a difference in these rates. But these rates for the hydro credits, energy credits that we talked about, are based on the use of the 10-year forwards that you --

A That is correct.
Q All right. And --
A At the time when the rates were developed, not the ones that currently exist.
Q So if the -- if the Commission were to find in favor of the Public Staff regarding the use of 10-year forwards or using the fundamental forecast for an extended period of time as compared to the 10-year forwards, these rates would likely be higher?
A Higher.
Q Thank you. The other changes that are reflected in the 10-year hydro rates, are those things such as just inflationary changes, other -- what other factors would change in a 10-year model run other than the energy rates?
A I think the energy rates are largely driven by the commodity prices. The capacity, I think, is the same. We've offered the -- there wouldn't be a different capacity payment that's under the current Company proposal, and that -- that is what we're really talking about because we said we'd fix the capacity rate for 10 years either way --
Q Uh-huh.
A -- so those wouldn't change, so the only thing

that we've proposed would be the energy rates.

Q Okay. Thank you. So I'd like to ask a few questions about the fuel forecasting methodologies. First, I'd -- I'd --

CHAIRMAN FINLEY: If you're going to change topics there, Mr. Dodge, let's take our morning recess, if that's okay with you.

MR. DODGE: Okay. Thank you.

THE WITNESS: Thank you.

CHAIRMAN FINLEY: So 25 after 11:00 we'll come back.

(Recess taken from 11:10 a.m. to 11:25 a.m.)

CHAIRMAN FINLEY: All right. Let's come back on the record. Mr. Dodge, I believe you have questions.

CONTINUED CROSS EXAMINATION BY MR. DODGE:

Q All right. Thank you. So I was just getting ready to switch subjects to the fuel forecasting methodologies discussion, and I wanted to note, Mr. Snider, as you've already noted today, that this issue spilled over several dockets, including the last avoided cost proceeding and the 2016 IRP that's currently pending before the Commission?

A (Snider) I think it was 2015 and 2016 IRP, so back in the '14 avoided cost we used -- or full market

'15 IRP, '16 IRP and this docket, so this is the fourth docket that we've submitted full market for 10 years.

Q All right. And I don't want to get down in the weeds too much with some of the -- the differences here for -- but for the sake of those of us in the room that aren't natural gas traders or haven't done that previously, can you provide just a general explanation on the difference between a forward price and a fundamental forecast?

A Yeah. Just real quickly, a forward price is not something you're paying for today. It's just an agreement between willing buyers and sellers at the price you will transact at that point in the future. So I'm not buying something and saying here's money out the door. I'm saying I agree to pay this price for this forward contract at this point in time, and you agree to sell it to me at that point time.

And if you have a liquid market, that's what you're able to lock into going forward through time. Where you don't have a liquid market, you rely on spot price estimates. So if you're 30 years out and there's not a -- a gas price that trades 30 years out, there's a host of different economic forecasts that are available that give a wide range of view on that -- what that spot price might be beyond the liquid market, and so that's economists, not market practitioners, but economists that come together and say here's what we think, based on supply and demand and our current understanding of the marketplace, prices might be when you get out in the future.

So one of biggest differences I'd like to point out is there's only one market price. You can trade at one -- at any point in time in a forward market you can only buy and sell at one price. There is a host of spot price estimates. As just a quick example, you know, I looked at Apple stock today. It's $142, one market price. Analysts say 12 months from now Apple stock -- some say 85, some say 185, and everything in the middle. So that's the same with -- with the gas market. There's a wide range of fundamental forecasts, but there is one market price that is transactable. So those are two of the big differences.

Q All right. Thank you. That's helpful information. Do -- does that -- with regard to the forward price, that one price that you indicated, does that price change on a regular -- is it on a daily basis?

A Yes. The forward price moves on a daily basis as the reflection of what the market believes, so Apple could be 144 today.

Q But the fundamental prices typically are, again, looking further out and are less volatile?

A Oh, no, I wouldn't say they're less volatile at all. They only change a couple times a year, but fundamental prices, they're -- they are not near as real time, but when you look at -- and if I can direct you to Figure 4 of my -- of my -- is this in my direct -- in my rebuttal, page 20, we show fundamental prices across time, and the fundamental prices have been extremely volatile so they move drastically. They keep dropping across this. And all I've shown is as we move through dockets, what have the fundamentals done across time. And they continue to drop as the market prices have dropped, but they continue to overstate the market.

So back in, you know, pre-fracking, the fundamentals said the price of gas would be $10 today. And so the fundamentals have changed drastically just like the market, so they're both very -- I mean, they both can be volatile, but I wouldn't say just because they only get updated once or twice a year they're not volatile.

Q So do you -- do you think that DEC and DEP's current fundamental forecast is accurate then?

A I think it is one of many fundamental forecasts, so do I think it's going to be the price gas will be when I get to that point in time? Absolutely not. I think there is a wide range. Neither is the market. There's a wide range of prices, and that's why in most of our analysis we do price sensitivities around that input.

Q So maybe putting it another way, instead of saying will be accurate, do you think that that fundamental forecast is reasonable?

A I do not think it's reasonable to use to set a forward price. That's one of the -- I guess one of the key differences in understandings here is I want to be very clear, there's -- there's two basic arguments when it comes to this that seem to be inextricably linked, but they shouldn't be. One is which one is more accurate. Is a fundamental or is a market price more accurate? And there is -- I've seen countless papers and debates on this, and it's -- it would go into ad nauseam as which one is more accurate and what the differences are.

And then there's a separate question of is it appropriate. Those are distinct and separate. And what I'm arguing is that in my testimony, if I could turn to Figure 2 of my -- let me go here to my rebuttal testimony on page 7. So let's talk about the appropriateness and the accuracy as two separate items. In Figure 2, what I'm showing is what are the recommended gas prices that Public Staff is recommending in this proceeding based on fundamentals, and that's the top line. That's that top red line. And it's saying because we have one of many fundamental forecasts that exist, and ours is very different than Dominion's, which is probably very different than three other people that you would bring in here, we're saying we should use that one spot forecast to set prices that we're going to be obligated to pay for the next 10 years. And as you can see, that red line is significantly above the actual tradable transactable market. That tradable gas market back when we set rates was that black middle line. And so that line is significantly lower 10 years out where you buy gas 10 years.

And then what I represent in the bottom blue line is there's been significant debate over the liquidity in the marketplace, the transactability, the ability of a participant to readily go buy gas this far out in the curve. And we have demonstrated in 140 that we went out and got quotes, but that didn't necessarily solve concerns other than there was liquidity, so in this docket we actually went out and we purchased natural gas. We bought gas 10 years out the curve at that bottom blue line.

So the Company now purchased gas going 10 years out the curve at that bottom blue line, so the -- the market that we can actually transact at is even lower than what we filed in November, and yet the fundamentals that we're using from 18 months ago, which probably took that firm a few months to develop, could be as -- as stale as two years are the red line.

So I think, you know, it's an extremely important issue. One of the things that -- that I think really has led to a systematic overpayment is the use of a fundamental spot forecast that, as I've demonstrated, has lagged and has not come down as fast as the market. So when there is a market, it -- you know, I used to do this in the non-reg side for a good chunk of my career, and you would always look for a dislocation in the market. Where can I buy at one price, but someone is willing to sell for me at a higher price?

So if I took a QF that comes in and let's say it was a natural gas burning QF, and they demonstrate I can buy natural gas out the curve for $3, the utility has priced their power as though gas was $5. Wow! What a great win for me. I come in. I take the utility's rates based on $5 gas, which equates to a very high avoided cost rate, I lock in my QF power as a steam host provider at $3 gas, and I arbitrage that difference, and that's at the cost of our consumers. And so I think it's just absolutely critical that when you have a demonstrated liquid market, that you don't give a free arbitrage to the community.

I can tell you that is exactly what -- why a lot of people would flock to a region, is if they see a dislocation. If they see I can buy one commodity here and sell it here and automatically lock in, that will attract a large amount, but it's only done because you're creating subsidy.

And so, you know, I just can't, you know, reiterate anymore. I think this graph shows it. If you look at --

Q Mr. Snider, before you leave that Figure 2, I do have a couple questions about it, actually --

A Sure.

Q -- so I may be --

MS. FENTRESS: Can Mr. Snider complete his answer, though?

MR. DODGE: Yes. I'm sorry.

MS. FENTRESS: Thank you.

A So I just wanted to say, you know, I -- as I also pointed on Figure 4, that's how -- look at where on Figure 4, rebuttal page 20, the fundamental prices over time have systematically for the last several years been incorrect. So we talked about the appropriateness. The other point I was trying to make is about if you believe -- and it's not an accuracy argument, but if you wanted to look at accuracy, I have -- I found it hard over the last five years to find a fundamental that has actually caught up to how fast technology is happening in the marketplace. It's not just hydraulic fracking. It's how great, you know, those improvements have been so that their lifting costs continue to drop, and so the marketplace is continually willing to trade at lower and lower prices, and the fundamentals that get updated once or twice a year just can't keep up.

And all you have to do is trace where the fundamentals have been for the last five years and where the market has been, and I challenge anyone to show me where you have a bunch of fundamentals that are below market. They have systematically been above market for the last five years, and so if we're going to establish rates on a fundamental curve in the presence of an actual liquid market, you're -- you're locking in those systematic higher rates.

Q Thank you, Mr. Snider. Could we go back to Figure 2 for a moment?

A Certainly.

Q So I appreciate you -- you highlighting this -- this figure. I agree there's a lot of useful information in here. And you pointed out that the top line with -- I'm looking at a black line, but you labeled as a red line, reflects the Public Staff's position in this proceeding?

A I said that, yes, that that is the -- Public Staff recommended the use of fundamentals. I simply took -- even though we didn't use those fundamentals in our IRP, I took the fundamentals that would have been used and extrapolated backwards to say here's what the fundamentals were. So if -- you know, to the extent Public Staff had a different fundamental curve or was amenable to a different curve, then it would a different line.

Q So to be clear, the Public Staff's position was to -- for the Utility to use the same approach that it had utilized in the 2014 IRP, which does this -- does the Public Staff's chart here reflect the Utilities' use of a five-year reliance on forward markets, then switching to the five-year -- the fundamental forecast from Years 5 and forward?

A It does represent what was done in 2014, but with the fundamentals from the 2016.

Q Thank you. So -- and I think it is helpful to -- to talk about -- you know, we're not talking about necessarily with forward prices or fundamental forecasts as accuracy, but appropriateness and the reasonableness of those values. Do you -- how often is the Utilities' fundamental forecast updated?

A About twice a year.

Q Twice a year. If it's -- if the market is changing so quickly right now with what you're seeing in the markets versus what's indicated in those fundamental forecasts, does it make sense to update that more frequently?

A If you look at most fundamental forecasts, it's sort of like the IRP process, right, except it's the IRP process for gas prices. And so they don't update their curves on a daily, weekly, monthly basis. Someone like an energy information association, a Cambridge Energy Research, a Wood Mac Energy, EVA, all these firms that do these long-term econometric forecasts that give you a host of different fundamental prices take months to develop these, and they generally publish them once a year, and occasionally will do a midyear update that doesn't involve all the analytics that went into their annual filing, but then just produce it on a update.

And this is part of the reason I speak about in my testimony why it's -- it's not appropriate to use those as a transaction -- transactable. They're a guide as to where things might be. They're never intended to be used in the presence of a transactable market as a transactable price. They're simply where spot prices might be based on the analytics I did months and months ago.

Q Are you involved in the process of DEC and DEP's development of a fundamental forecast?

A That is not under my direct responsibility. We are one of the primary users, so I do give them input in terms of my needs as a consumer of those fundamental prices and how we need them to support the IRP.

Q And with regard to the IRP and this present avoided cost proceeding, what other matters does the Utility rely on the fundamental forecast to support?

A The Utility relies on the fundamentals to support their estimate of where spot prices will be beyond the liquid transactable curve for the IRP process that looks out 30 years and beyond. When it does the analytics, it gives a 15-year plan, but to give that 15-year plan, we say how do these resources perform over 30 years, and we generally look at a range of fuel prices when we do that. So it's the IRP, which doesn't involve a direct transaction, but then we also would use a range of those when considering a technology -- one technology versus another for recommendation to -- to be built.

Q Does the fundamental forecast, is it utilized for fuel procurement practices to guide fuel procurement?

A Not to my knowledge.

Q Do you have your rebuttal testimony with you?

A I do.

Q Could you turn to page 23 of the rebuttal testimony?

A I'm there.

Q All right. And I'm looking specifically at the question starting on line 15 and your response starting on line 19. On that page you comment that Public Staff went -- Witness Hinton's -- excuse me -- view is that long-term forward contracts are illiquid. And then you state on page 24, line 8, that -- and I'm just going to read from line 8 -- you state, "Based on my experience, long-dated forward contracts are liquid and transactable and may be purchased over-the-counter directly with large financial institutions and other firm rather than traded on the New York Mercantile Exchange." Did I read that correctly?

A You did.

Q All right. Are gas transactions -- so you're -- you're kind of pointing to two markets. There's the bilateral transactions that may occur between large financial institutions and what might happen on publically traded platforms like the NYMEX.

A That's correct.

Q And are there other major areas where natural gas is transacted other than those two?

A I mean, you could go to ICE, which is the Intercontinental Exchange, which is another brokerage firm or clearinghouse similar to NYMEX where it's exchange traded versus bilateral traded through large financials, yes.

Q Okay. Great. And actually that leads to my next question in a -- in a cross examination exhibit.

MR. DODGE: And Chairman Finley, I apologize. I dated these for yesterday and was overly optimistic when we would get to this information, so I apologize for the date being April 18th, but I'd ask that these be identified as Public Staff Snider Cross Examination Exhibit Number 1.

CHAIRMAN FINLEY: Let me get a look at it. We'll mark it for you. The exhibit to which Mr. Dodge has referred shall be marked for identification as Public Staff Snider Cross Examination Exhibit Number 1. We'll change the date to April the 19th.

MR. DODGE: Thank you.

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

Q Mr. Snider, when you've had a chance to look through the document, let me know.

A (Snider) Okay. I see it.

Q All right. And so this is -- actually, before we go into this document, this cross examination exhibit, one last point on page 24 of your testimony.

A I'm sorry. Direct testimony or rebuttal?

Q Rebuttal. I'm sorry. Rebuttal testimony. You -- you state, and this is on line 11 starting where I had stopped reading. On line 11 it reads, "If one is simply viewing contracts to trade on the NYMEX, that could lead to the conclusion that long-dated gas markets are illiquid." And so as you were --

A Yes.

Q Did I read that correctly?

A Yeah.

Q Thank you. And so you were just alluding to NYMEX and the Intercontinental Exchange being one of these trading platforms --

A Right.

Q -- for commodities. And the cross examination exhibit I submit to you that we just provided is a printout of the -- of an end-of-day report from the Intercontinental Exchange.

A I see that.

Q Thank you. And subject to check, would you agree that the NYMEX Exchange and the Intercontinental Exchange are two of the largest energy exchanges where natural gas futures are traded?

A Yes. They are for the short-term market. Yes, they are.

Q All right. And this document is publically available on the website listed at the -- at the bottom of the first page. Could you turn to the page labeled as page 3, the handwritten page 3.

A Oh, I see. Yes.

Q All right. Now, specifically I wanted to point to two columns. One is the Contract Month, which I've added an asterisk above, and then also the Total Volume column. Do you see those two columns?

A I do.

Q All right. And on that first row in the -- that I've indicated with an arrow, it indicates a contract month of May 2017, and the total volume for that contract month on the Total Volume column indicates 228,991. Do you -- did I read those numbers correctly?

A Yes.

Q Okay. Now, so can you describe what that column or that row represents? What is that --

A The number of contracts that traded for the May future.

Q Okay. Thank you. And so moving down to the next arrow where I've highlighted May 2018, for the May 2018 contract month or contract ending that month, the -- the total volume is 9,693; is that correct?

A Correct.

Q All right. And I'll just repeat this a couple of times. To the bottom of that column from May of 2019, the volume was 1,368?

A Correct.

Q Okay. And I won't belabor this, but just flipping to page 7 of this chart.

A Yes.

Q This is going out 10 years.

A Right.

Q The line that's indicated with an arrow from May of 2027, the total volume at that point was zero?

A Yes.

Q Okay.

A So that's because this is ICE, and I stated in my testimony this is what you would expect. And if this was your only view of market liquidity, you would draw a conclusion that long-dated markets aren't liquid. This is not where you trade long-dated. This is not how the market has evolved.

The market evolves to long-dated trades happening with financial -- many financial brokers. You can call up J.P. Morgan, Morgan Stanley, Citigroup, Bank of America, Macquarie, BNP Paribas, Bank of Montreal, I could go on and on, and there are several individual counterparties that will make very transactable, very simple -- when my -- when our group bought this, it took their trader one minute to make that transaction. It is not a big, complex deal. It's a very simple thing to pick up the phone and buy 10 years of natural gas.

And if you would go to my exhibit that I was pointing out earlier, we -- we demonstrated that you could buy that gas for the next 10 years very simply at a price significantly lower than the fundamentals are currently projecting.

And so the -- the point here is, is when you have that liquidity, not only is it inappropriate, it really sets. When you have liquidity, it makes it a free arbitrage. So that's what I was talking about earlier, is I -- just because something is not trading on ICE does not mean it's not liquid. It means it's a different format in which they trade. And I can tell you as we've gotten these quotes, we got them from multiple counterparties. Those quotes were within a penny of each other or a couple pennies -- I don't want to say one penny -- a couple of pennies of each other, and it was very easy to transact.

So this is a very liquid, long-dated market if you want it to be. The point is the market can move 10 years from now, so can fundamentals. But as I point out, to say that we're not liquid because we're looking at an ICE exhibit is to say that this is where natural gas trades. Natural gas does not trade on ICE alone.

Natural gas trades in multiple market formats and platforms, and there is a liquid market out deeper in the curve that unless you deal with those participants or talk to them on a regular basis, you may not have knowledge of, and so I understand that. If you're not in the market, you might not just be able to pull up a screen the way you can with ICE, but it is very liquid.

It's very much demonstrated, and the Company went out and actually purchased to demonstrate that liquidity, and that was not just one -- and we could have done multiple purchases, we could have done much bigger volume, but we wanted to demonstrate this very issue of liquidity. And just to highlight, again, on -- in my rebuttal testimony, the extreme overpayment risk if you lock into the red curve on page 7, line 1 of my rebuttal testimony, if you lock into any version of that red curve, whether it's that red curve, whether it's a curve that's halfway below that, whether it's a curve above that, you are making a forward transaction with the QF market that you are obligated to. It's not an estimate of spot price at that point. You are obligating customers to pay that point -- that price point into the future for the next 10 years, the next 15 years. However -- whatever term that you've agreed to, you're obligated to.

When you have a transactable liquid market, you create this immediate overpayment risk that is part of what, you know, we're seeing today, is that -- that difference between fundamental and market and just how the fundamentals have systemically overestimated market for five years. And so to continue to rely on that practice going forward in the face of a demonstrated liquid market is simply to say I -- I'd prefer to subsidize.

Remember, the QF has the -- if the QF believes this, if the QF believes the red line PURPA envisions, it gives the QF the option take the demonstrated forward market or, at your discretion, wait and take the market as it evolves over time. So QFs have the right to pick either one. What we don't want to do is say, geez, we think the forward market might be wrong and then their spot market is even higher. Let's allow the QF to lock that in today. That has never been the intent of PURPA. PURPA says let the QF make the choice a transactable forward or, at their discretion, at the time of delivery. It doesn't say assume that at the time of delivery it's going to be a lot higher and just let them lock into that today. So that's -- that's, in essence, what we've been doing.

Q Thank you, Mr. Snider. And I do want to come back to the -- the fundamental forecast a bit later and how the Utility constructed its fundamental forecast that is the basis for the line and the Public Staff's recommended position there. That -- some of that is confidential, so I'll reserve those questions for a bit later.

You mentioned just a few moments ago, though, the recent 10-year purchase that the Utility has made. On --

A Yes.

Q On page 21, if you could flip to page 21 of your testimony.

A Is that rebuttal or direct?

Q Rebuttal testimony.

A Thank you.

Q Most of my questions at this point --

A Okay.

Q -- is going to be on rebuttal testimony. And so on page 21 of your rebuttal testimony, you indicate that DEP recently purchased a 10-year forward. In fact, it was about two weeks ago. It was two weeks ago you made that purchase?

A Yes, it was.
Q Okay. And what kind of transaction was that 10-year forward?
A A forward swap.
Q Forward swap. All right.
A A NYMEX settle similar to the ones you just saw in ICE except instead of being a future, it's a -- a swap.
Q Has the Utility at any time prior to that made a similar 10-year forward purchase or 10-year swap?
A Not to my knowledge.
Q Okay. Would you characterize that 10-year forward purchase as a substantial long-term obligation on the part of the Utility?
A I would characterize it -- to put it in perspective, so, you know, how much did we buy, the equivalent gas, it's about -- it would produce about the same megawatts as 50 megawatts of solar, so we bought -- you can think about this. Again, the Utility can either buy the commodity or it can by the power. It should be indifferent between the two. That's sort of the indifference principle in PURPA, is I can -- I can go out and buy the commodity or I can buy the power. They should be the same price. So we bought about 50

megawatts of solar going forward for 10 years.

Q Thank you. That is helpful. I didn't realize the basis for the -- the volume that was transacted.

A It wasn't the basis, but it is the -- what it translated into the equivalency of. It's a quarter a day or 2,500 MMBTUs a day, which equates to about 50 megawatts of solar in terms of megawatt hours.

Q And -- thank you. And in discovery to the Public Staff, you noted that the Companies first began evaluating this issue in late 2014; is that correct?

A Yes.

Q Okay. Late 2014 or early 2015.

A Yes.

Q Turning to page 27 to 29 of your rebuttal, or turn to page 27 -- I'll give you a moment to get there.

A I'm there.

Q All right. So you -- in this section you talk about the divergence between -- and I'm actually looking at the very last line of page 27 and kind of spilling through Figure 6 over to 29. You talk about the divergence between DNCP and Duke's fundamental forecast; is that correct?

A Correct.

Q Do you agree that DNCP's approach relies on the shorter term use of forward prices before blending the values to transition to their fundamental forecast?

A Yes. I see that that's how they do it.

Q And do you think that approach is reasonable?

A Reasonable for maybe IRP planning. Again, I think as I've stated, it's wholly unreasonable to set rates based on a spot estimate when there's multiple ones out there. I think what you'll find yourself, then, is the future proceedings will now be which fundamental are we going to argue over as opposed to this is the market, it's demonstrated liquid, it is the appropriate. So, no, I don't think it's appropriate to set long-term rates based on one particular estimate of many of spot prices when you have a transactable forward market.

Q Thank you. Would you agree that DNCP's approach, however, is similar to the approach that DEC and DEP took prior to -- well, in the 2014 IRP?

A No, I don't believe it is. I think they blend much earlier.

Q But they -- it does reflect a shorter term use of forward prices before blending to -- the blending point is different, but the -- the blend to the fundamental forecast?

A Yeah. We both go to a fundamental forecast at a point in time.

Q Thank you. And in the 2014 avoided cost proceeding, the Commission directed the Company to revise its fuel forecast to be consistent with what it had used in its last approved IRP; is that correct?

A I think, yes, that it said to revise not the -- to revise the inputs to the calculation of avoided cost to go back and use what was in the IRP.

Q All right. Actually, could you turn to page 16 of your rebuttal testimony just to make sure we're there? I know the Sub 140 proceeding has been stipulated in the Order on this point, but you quoted in your testimony, so I just want to --

A Uh-huh.

Q -- refer to that. On -- let's see. I'd like for you to read, if you don't mind, Mr. Snider, starting on line 11, the -- the quote the Commission directed that. Could you read that line?

A "The Commission directed that, to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in the avoided cost calculations."

Q Thank you. And so just to repeat the key phrase here, I think, the -- those changes, the Commission directed the Utility to propose those changes, first is in the biennial IRP proceeding and for those to be approved in the IRP proceeding?

A Yes.

Q Thank you. Now, on page -- could you turn to page 30 of your rebuttal testimony?

A I'm there.

Q On page or -- excuse me -- line 7, I'll read from the line starting "The Public Staff..." "The Public Staff and other intervenors have failed to sufficiently explain why at this time the Company should depart from the Commission's directive in its Phase 2 Sub 140 Order and not remain consistent with their previous IRP filings with respect to their fuel forecasts." Did I read that correctly?

A Yes.

Q All right. Thank you. And which previous IRP filings there on line 10 were you referring to?

A So I've made the -- I think I made this point. I'll make it again. We've filed this now four times. We filed fundamental starting in year '11 starting with Sub

140. We have used market prices for 10 years in the 2015 IRP, the 2016 IRP, and in this proceeding. And, yes, although those -- the ’15 IRP was approved, the ’16 IRP is pending approval, there were no comments in the ’15 IRP about 10-years’ worth of market. Those arose in the ’16 IRP, which is the biennial, which is yet to be approved. So, you know, I think that, you know, what’s before this Commission is what was the intent of that Order.

Was the intent of that Order, to say two years down the road after you've filed this four times, that the administrative lag in terms of the difference of when we approve an IRP and when we file an avoided cost case should be precedential, and that we should go all the way back to ’14 simply because we filed it four times? But if you were to say has it been -- the ’16 biennial been approved, you know, I think that faces this Commission is what was your intent at that point in time? I would say your intent was let us see this in the IRP prior to coming to forward in the -- that was my read of your intent.

And, of course, I don’t want speak for the Commission, but we've filed this now four times, saying that this is appropriate specifically in one of the --

you know, A, it's more -- it's liquid, we've demonstrated it, we've transacted at it, and that to set rates in any other method is to simply invite an overpayment that we'll be sitting here two years from now and will no longer be 1 billion, but will be multiple billions.

Q Thank you, Mr. Snider.

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

CHAIRMAN FINLEY: We will mark this exhibit that appears to be a section of the Order in E-100, Sub 141, as Public Staff Snider Cross Examination Exhibit Number 2, and we'll change the date to April 19th.

MR. DODGE: I apologize. All of my exhibits I'll use today have the April 18th date. They should all be revised. Thank you.

CHAIRMAN FINLEY: Let's just not change them to the 20th.

MR. DODGE: Do my best.

(Whereupon, Public Staff Snider Cross Examination Exhibit Number 2 was marked for identification.)

Q Mr. Snider, have you had a chance to look at this document?

A (Snider) Yes.

Q You know, would you agree that this is an excerpt from the Commission's June 26, 2015 Order approving the Utilities' 2014 IRP?

A Yes. The June of 2015 Order reaching back to the September IRP, right.

Q Correct. Yes.

A Yeah.

Q Thank you. Could you read the first two ordering paragraphs that I've highlighted on page 54?

A In number 1 ordering paragraph, "That this Order shall be, and is hereby, adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1."

Q All right.

A And then 2, the IOUs -- "That the IOUs' 15-year forecast of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads and reserve margins are reasonable for planning purposes and are hereby approved."

Q Thank you.

MR. DODGE: And so I have a second cross

examination exhibit. Chairman Finley, I'd ask that this exhibit be identified as Public Staff Snider Cross Examination Exhibit Number 3.

CHAIRMAN FINLEY: It shall be so marked.

(Whereupon, Public Staff Snider Cross Examination Exhibit Number 3 was marked for identification.)

Q Mr. Snider, have you had a chance to look at this document?

A (Snider) I have.

Q Now, would you agree that this is the Commission's -- I may have read the wrong date earlier -- the Commission's March 22nd, 2016 Order accepting the filing of the 2015 IRP update reports?

A Sorry. Let me look at this again. Yes, I see that.

Q And on the last page, page 8, I highlighted the conclusion paragraph, and I'll -- I'll read it here. "Based upon the record in this proceeding, and the comments of the Public Staff regarding the IRP Update Reports and REPS compliance plans submitted by DEC, DEP, and DNCP, the Commission hereby accepts the Update Reports filed by the Utilities as complete and fulfilling the requirements set out in Commission Rule R8-60." I'll just stop at that point. The last sentence is --

A Yeah.

Q -- dealing with REPS. So Mr. Snider, you're very involved in the IRP process. I know we spent a lot of time talking about that for much of the year.

A Yes.

Q And you -- you were involved some of the revisions to the rules in 2014 and 2015 to change -- or excuse me -- 2014 to change the update reports, the odd year IRP filings?

A Yes.

Q And those are viewed as, again, as an update, and parties don't file comments on the updates. The Public Staff did file a -- as is noted here, comments regarding the completeness of that update report, but not comments on the inputs or other assumptions that went into that report?

A I know that the Public Staff is the only one that comments on an update year, but we did respond to numerous data requests from Public Staff, including all of our inputs in 2015, so I'm assuming that the Public Staff did review those extensively because we had extensive data requests that we provided in 2015. So, yes, I'm -- I think Public Staff did -- was the only party, but I wouldn't say that they did not get a chance and a very adequate chance to look at our inputs.

Q Thank you. And the last point on this issue I was -- I'd like to make is that the 2016 IRP that's currently pending before the Commission in Docket No. E-100, Sub 147, as you indicated, DEC and DEP proposed similar adjustments to their 10-year forward price for natural gas in that filing?

A I would say we've been consistent, as I said, in '16 with the two previous dockets and this docket that followed, so I don't know that it was a big adjustment. It was a continuation of what we've done since the Sub 140 filing.

Q Have you reviewed the Public Staff's comments filed in Docket No. E-100, Sub 147?

A Yes, I have.

Q And did we take exception to the natural gas forecast?

A Yeah. That -- that is true. I think there were -- that's part of the reason in which we, you know, we went to great lengths to address those concerns. The concern stated in the IRP was that the market is not liquid, so I think we've definitively shown that it is liquid. We can -- we can readily transact very readily at a -- at a known price for 10 years out. So that was one of the concerns raised.

The other was that it was overly conservative, and that that's been a constant theme, is that the market has been too low. The market is wrong, the fundamentals are right, and we've got to go with fundamentals. Well, the overly conservative comment had we made back in 2014, we would have -- we would have said the market is overly conservative. And if you go to my graph where I look at our -- our last several filings, we actually show here's what the market has done and here's what the fundamentals have done over the last several filings.

In my rebuttal testimony, on Figure 3, page 18 of my rebuttal testimony, we show over the last several regulatory filings where fundamentals have been versus the market or what's been used in those filings. And so if you look at the top line, and mine is getting small, it's actually what's been used in the filings, is in Sub 136. So the rates that are still now in effect, you know, we -- we set those rates back in 2012, but we still have 10 years of payments to make to a significant number of QFs who have established LEOs under Sub 136. We relied on that top blue line in Sub 136 which had a large dependence on fundamental prices.

We walk down to the green line, and that's what was originally filed in Sub 140. That's what the market was trading back when we did Sub 140. But the red line is the fundamentals that were in the 2014 IRP. So, you know, after the Commission's Order came out, we went back and redid avoided cost rates not using the green line, but using the green line and then going to the red line. So that's what was ultimately used in 140.

Then as you walk on to the next three IRPs, you have the purple line, the blue line, and the orange line that shows that the market has -- which have all been 10 years of market, and each time we've said that's too conservative, only to come back a year later and find it lower, and then only to come back a year later and find it lower, and yet we continually want to set avoided cost rates not on the market, but on the fundamentals that I showed on another graph have continually lagged over the last five years the market.

Finally, the orange line represents what's been filed in this docket, and says, you know, here back in November is what we've transacted a 10-year -- or what we got quotes for the 10-year market. And then upon our purchase, after seeing that still we needed to demonstrate liquidity and we actually -- to show it was very liquid, we actually bought at that bottom line. So the bottom line is where the market existed as of, I think, the 7th or whenever we made that purchase, you know, 10 days, two weeks ago.

And so very specifically Public Staff's concerns have been, one, liquidity, and I can see where if Public Staff was just looking at ICE, they would draw that conclusion. So I'm not faulting them for that. The fact of the matter is they do not transact in the marketplace. They would not know to call one of a, you know, a dozen financial institutions and -- and get a quote for those prices. So I can -- I can see where they'd have liquidity concerns. We have -- we have more than demonstrably demonstrated there is a liquid market. So the liquidity concern was brought up in the 2016 IRP. You know, the -- the ability to transact, we've demonstrated an ability to transact.

And then also the overly conservative, and I think in the 2016 IRP the specific comment was made this will have an adverse effect on avoided cost. Well, I'm not trying to have an adverse effect on avoided cost. I'm trying to say here's what avoided cost is worth. It's not good. It's not bad. It is what it is, and here's what the market is, and not to say I shouldn't use this because it might lower avoided cost rates. So I think when you look at the IRP comments that came out in 2016, it was liquidity, transactability, and whether it would have an adverse impact. I'm -- I can't address adverse impact because it is what it is, but we've demonstrated liquidity, transactability, and we've shown that it is appropriate.

Again, there's accuracy and appropriate, and we've demonstrated when you have a liquid market, that is the only way to set a forward -- because, remember, we're not setting a spot price. We're setting a forward price. We're obligating ourselves, just like we did all the way back in that blue line to these prices that we're going to be paying for the next decade. So in the face of this market being liquid, being transactable, and demonstrating what the Utility can buy at, it's imperative that if you're going to set longer term rates, that those are the prices that are used in the derivation of those rates, unless the intent is simply as concerned, is it's going to lower avoided cost and we'd rather have higher avoided cost rate, then we can go to spot.

Q Thank you, Mr. Snider. And I appreciate some of the key words you're using about, I agree, are the heart of this issue; transactability and liquidity. And you mention on that figure the quotes that the Utility obtained back in the fall when it was preparing these rates. Were those quotes that you obtained transactions?

A No. They were transactable.

Q Transactable. Thank you. And -- but now there is a transaction that has transpired?

A The -- yes. The transactable quotes were at the orange line, and we've actually bought the gas at 6 -- what I testify in my testimony is 6 percent lower on a 10-year levelized basis than the numbers that went into the rates that are before this Commission in this proceeding. So we've actually purchased gas at a 6 percent lower 10-year level than what went into the rates when we filed in November. And the argument before this Commission -- this is why I said in my rebuttal testimony, you know, it's so important to take a macro view and not get lost in three-days' worth of academic -- you know, in the real world the gas market has declined, it is liquid, it is transactable. And when we get into these academic arguments and say, oh, well, we should still pay something above that transactable, that's where we find ourselves creating a significant overpayment risk.

Q Thank you, Mr. Snider. And just one last point on that issue. And I recognize you -- you have made the one transaction. Is -- does one transaction indicate a liquid market? Is one transaction liquid?

A It certainly does, and it's this matter. It's not is it liquid for Duke. It's is it transactable in the marketplace for anybody? For us? For QFs? For -- you know, we're not saying Duke creates the entire natural gas market liquidity. What I've demonstrated here and with our quotes is it's not from one person that was very difficult and it took months for them to get approval to do this. You can call and they can transact with you like this (snapping fingers), and there are literally multiple, multiple counterparties willing to do that with you at very similar prices with a very small bid versus ask spread. That's a demonstration.

Someone who used to do this, again, for a long part of my career, liquidity comes in, can I get the same price from multiple counterparties and can I transact pretty readily and check all those boxes when it comes to 10-year gas transactions. I can readily do it. So can a QF. And, again, my example is if we had a co-gen come in here who could burn gas and produce steam and sell its power to the citizens of North Carolina and they could come in and secure their gas for $3, but we developed avoided cost rates based on $4, then they lock in that differential. They say, great, the Commission and the Utilities came together and decided that $4 gas is how they want to set avoided cost rates. That provides, even though the Utility also is a natural gas burner, I'm going to be able to come in and buy my gas at 3 and then sell it to North Carolina consumers at 4, at the equivalent of $4 gas, and lock in that artificial spread.

And that's why I said, you know, appropriateness versus accuracy aside, it is never appropriate to set a forward market that you're willing to transact on today that is in conflict with a transactable liquid market. You'll create arbitrage and the marketplace will swoop in to take advantage of that arbitrage.

Q Thank you, Mr. Snider.

MR. DODGE: And the additional questions I have on the fuel forecasting methodology are confidential in nature. I'll save those -- reserve those, if that's acceptable, Chairman Finley. I do have some questions on the Performance Adjustment Factor. I think most of these are also for Mr. Snider.

Q So Mr. Snider, on page 50 of your rebuttal testimony -- turn to that page.

A (Snider) I'm there.

Q I'm at -- I'm sorry. Actually, I think my questions are on page 49 dealing with the Public Staff's -- or baseload availability factor that Witness Metz provides in his testimony. This is starting on page 49, line 4, continuing down through page 50.

A Yeah. Okay.

Q And Mr. Metz indicated that this was calculated on an average availability factor for the baseload fleets of the three Utilities. In the past, the Public Staff has made a similar calculation based on baseload performance. Mr. Metz did modify the -- the units that are included in that calculation of a baseload performance to recognize some of the changes in how the fleets were operating. As you've indicated, the --

A Right.

Q -- natural gas and coal fleets are operating differently now than they may have, you know, five, 10 years ago.

A That's correct.

Q And do you agree that it's appropriate to make adjustments to kind of what's considered a baseload unit for performance data?

A Do I believe it's appropriate to look at the baseload units and say what's their availability? If done correctly, yes.

Q Thank you. And you agree that the Public Staff took an appropriate position when it looked at availability factor as opposed to the capacity factor of those units over the -- over the year? Your issue was more with the -- looking at the annual availability as compared to the on-peak availability; is that correct?

A Yes. To be clear, a QF does not have to be available. Let's make it clear. They can get their entire annual capacity payment without being available less than -- they can be available less than 25 percent of the time and receive an entire year's capacity payment, and that's because capacity is paid to the QF over a very finite number of on-peak hours. In Schedule B less than 25 percent of the hours in the entire year are on peak, so the QF technically, if I'm a co-gen burning QF, I can be off 75 percent of the hours and still get an entire capacity payment.

Clearly, the Utility already would not be able to do that and receive their -- if they were unavailable 75 percent of the time, they would not be entitled. So what -- what's so critical here is that we recognize that the QF is being paid its capacity during these very finite period of hours that allows them ample hours for maintenance, for -- if it's refueling, if it's -- if they need to upgrade their equipment, they have 75 percent of the hours in a year that they don't have to provide availability and can still receive their full capacity payment.

So when you look at, you know, how do we put them on par then with the Utility, it's unfair to say let's look at the annual availability of the Utility's generation fleet when we're paying for capacity for the QF only during these very finite on-peak hours. So on the on-peak hours what I've recommended in my testimony is that if you hold the QF and the Utility on an apples-to-apples basis, that you would look at how available are those same generators that Public Staff looked at. And I have no problem with their selection of those generators, but if you said what's their availability on peak. So let's not take a nuclear plant that is available to meet all of our peak demand needs and penalize it for being off during the off-peak period in a way in which we don't do with the QF.

So if you looked at an apples-to-apples comparison of the on-peak availability of a Utility fleet, the baseload fleet that Public Staff looked at, or

Ms. Bowen pointed to all those plants where she pointed, look at their equivalent forced outage rate, which says when needed, when needed for peak, when needed for that polar vortex morning or that hundred degree summer afternoon, or just a hot day or a cold day in the winter, what's your availability metric at that point in time, then compare the QF to that, that's how we came up with a 1.05, which says we have an equivalent forced outage when needed. It's actually less than 5 percent of the time, but to make for ease and rounding, we said at a 5 percent, would say okay, QF, you are now on an equivalent apples-to-apples basis in the real world with the Utility generator. When you look at the whole year, that does not have a -- a apples-to-apples. That's apples-to-oranges, because the QF doesn't have to be available the whole year.

Like I said, less than 25 percent of the hours is when they can earn an entire annual capacity payment. That alone would suggest that they're already getting a pretty good deal, because I don't believe, as other witnesses have contended, that we're not held to high standards. I think our operational standards are -- we're held to very high standards, both by ourselves and by this Commission, such that if, you know, we were not available, you know, as Public Staff shows, you know, if we were not available 14 percent of the time, which is the PAF that they're recommending, across the peak, that would be like saying that during all peak hours we had 5,000 megawatts offline and that this Commission would be -- find that prudent, acceptable utility practices, is to be 5,000 megawatts offline across the peak. That's the equivalency. And I don't think that that's a fair apples-to-apples comparison.

So, yes, I think on peak is absolutely critical when you're looking at availability when you compare it to how the QF is being compensated for capacity.

Q Thank you, Mr. Snider. And I'll try to keep my questions on this fairly brief, but if you could try to also keep your answers to the questions I'm asking brief, I would appreciate that as well.

A We're going towards lunch.

Q Yes.

A You got me.

Q So briefly, you talked about the 25 percent of on-peak hours. There are different options that QFs can choose from that may represent a larger number of hours than the Option B, I think, is what you're referring to, the 25 percent of those hours?

A To my knowledge. I don't know of any solar QFs that have taken anything other than Option B. So there was an Option A. I think we originally said we should go to an Option B, and it was Public Staff that said, no, we don't want you to eliminate Option A. So if it was the Utilities' choice, we would just have Option B, but there is an Option A that, to my knowledge, very little QFs are taking.

Q And that Option A has a larger number of hours that may be more applicable to, say, a landfill gas generator or biomass generator?

A Right, who, if they were producing it, a baseload would still receive their full capacity payment.

Q All right. Do you agree that in past proceedings, including the Sub 140 Order that's been stipulated in, that the Commission found that if the QF operated during 83 percent of the on-peak hours, that it was considered reasonable and that the QF should be entitled to earn a full capacity payment?

A I think many factors have changed since those Orders, and that's why we brought it up. I think we've said that if you actually look at the apples-to-apples comparison, that if you do compensate them for 100 percent of capacity -- again, from a macro perspective we're already paying for capacity that when applied to a solar specific rate is not avoiding capacity. We're giving it 40 percent capacity value as we sit here today with the filed rates, and we're proposing to make that rate higher. Let's take that multiplier, apply it to a rate that is already overcompensating and make it higher. So from a macro perspective and from the specifics of the issue itself, that is not justified.

Q Right. And do you agree that the Utilities have capacity needs outside of their peak hours and that QFs can provide capacity during those hours, too?

A In the extreme, capacity would be in every hour. We have -- you know, the hours are energy. The true need for peaking or for capacity -- not just peaking, but capacity -- does come across your peak, but I think it would be -- if you wanted to go down that, then you would have to pay capacity over all hours and not just over the peak. So -- but right now if we paid QF capacity over all hours, they would not be earning anything at night, and so the capacity payment they would receive would be far less than it is today.

And then if you -- if you then said, yes, I'll pay it over all hours, all capacity hours, then the equivalency factor that you brought up would be more appropriate, but we would have to then say you have to earn your capacity payment by being there in all 8,760, and if whatever percent you're there is how much capacity payment you get, and then the performance factor that you recommended would be more appropriate. But the fact of the matter is, is we don't pay them over all 8,760 hours, so we've got this mismatch where we're not apples to apples.

Q Thank you. Now, are all the Utilities' resources expected to operate at a 95 percent availability factor during those on-peak hours to fully recover their costs?

A I think, as I've stated before, there's different, you know -- they were held to prudent standards. I will point out the Utilities are the ones with an obligation to serve. The QFs do not have an obligation to serve. And this Commission deems what's prudent operating practices. I think I spoke yesterday to the -- you know, if you looked at a nuclear generator, they have to deem themselves as a baseload generation as prudent, which includes a very high availability, much higher than what's recommended by Public Staff, or be subject to a prudence review and disallowance of potential fuel, replacement fuel cost. So, yes, I do think we're held to very high standards both internally and as we come before this Commission.

Q All right. Thank you. And I think we -- part of that point we -- you wouldn't look at just a single unit or a single facility. When you're looking at this question, you would be looking at the Utilities' overall ability to meet the system peak from a systemwide -- on a systemwide basis?

A Yes. In my rebuttal testimony, that's exactly what we did. We looked at what is the fleet's, not one unit, what's the fleet's on-peak availability, and that's how we came up with the 1.05. So I want to make sure we're not saying we looked at just a nuclear unit or a set of units. We looked at the fleet's availability when needed to meet peak, consistent with the way the QF is being compensated for peak, and an apples to apples would justify a 1.05.

Q And would you agree that the reserve margin that's utilized by the Utility accounts for some portion of that -- that fleet not being available to meet the system peak, that there is a -- not a cushion, but that there is a portion of that that is viewed as operating in reserve?

A The reserve margin has multiple influences. It is certainly not just for peak availability of your resources. It does -- does recognize generators can be offline. That's why you have -- part of why you have a reserve margin, but part of it is for load uncertainty, like spikes during a polar vortex, so you need a reserve margin for that. Long-term forecast error. If you have generation needs quicker than expected, you need to be able to serve that. So there are multiple inputs. And, again, it points out to if we adopted Public Staff's availability metric, our reserve margins would need to be significantly higher than what we filed.

So if we are only available 86 percent of the time during peak, we could not come to this Commission in the IRP process and say we need a 17 percent winter reserve. If we were to adopt that on-peak availability, we need high 20s, 30, to accommodate having that lack of availability during peak. So that's part of the disconnect, is we have a reserve margin that's built upon being largely available at peak, you know, with only a very small, you know 3, 4 percent of our units out during peak, and that's what goes into the reserve margin calculation.

So if we were to assume 16 percent of the units or 14 percent of the units weren't available, we'd come to this Commission and say we need a much higher reserve margin. So I would say to be consistent with our reserve margin calculation that's presented to this Commission, we would need to go to the 1.05 PAF.

Q Right. And just a couple last questions on this point. Would you -- you just noted, Mr. Snider, that the Utilities are currently using a 17 percent reserve margin; is that correct?

A Seventeen percent winter reserve margin, yes.

Q Thank you. And so under the analysis that you did reflecting the Public Staff's position that an 86 percent baseload availability factor is -- is inappropriate and that that would result in the Company having 5,000 megawatts of generation unavailable during the -- the Utilities' peak, using the reserve margin of 17 percent doesn't that indicate, though, that the Utilities could have 6,100 megawatts above the system peak?

A See, and that's a very important point. It does not. And see, what -- what's done there is the availability factor that the Public Staff used. And, again, I think it is appropriate to look at availability, and -- and I went into a great deal of debate yesterday with Ms. Bowen about on peak versus annual without sort of backing up first and saying Utilities need to take generation offline during times of -- of not peak, so nuclear generators need to refuel, but we never do that across the peak. Those times during off peak where the generator is brought offline, whether it's for maintenance or for refueling, went into Public Staff's calculation.

That is -- you know, in the reserve margin, we recognize we're taking those offline when we don't need them. It's only how much of that Utility generation is not going to be available during critical peak hours that causes you to need a reserve margin. So the cause for reserve margin, we certainly didn't assume 17 percent or 16 percent of our resources are going to be offline in any given hour; we recognize in the creation of that reserve margin that we're going to be highly available during on-peak periods, similar to the on-peak periods that we pay capacity to the QFs. And so to use an annual that pulls in these off-peak outages and then comparing it to your on-peak availability is this apples and oranges and that we keep getting here, which, I think, using availability is -- is a step in the right direction. You just have to apply it to the on-peak period because that's what drives our reserve margin, that's what drives our need for capacity, not the annual availability.

Q Thank you, Mr. Snider. And you just talked about kind of maintenance cycles for facilities and planning outages. Would you agree that a generation plant, regardless of the fuel that it uses, has a specific maintenance cycle that's planned or engineered in the life cycle of the plant that accounts for wear and tear and --

A Yeah. They're very, very specifically planned away from our peak periods, and that's one of the operational disciplines that the Utility has.

Q And, again, part of the --

CHAIRMAN FINLEY: This is three -- this is three questions, Mr. Dodge.

MR. DODGE: Okay.

CHAIRMAN FINLEY: We're going to break for lunch.

MR. DODGE: Two. All right.

CHAIRMAN FINLEY: Come back at 2:00.

MR. DODGE: We're breaking?

CHAIRMAN FINLEY: Yes.

MR. DODGE: Okay. Thank you.

(The hearing was recessed at 12:35 p.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

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

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 2nd day of May, 2017.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150