PLACE: Dobbs Building
Raleigh, North Carolina
DATE: Wednesday, January 8, 2020
DOCKET NO.: E-100, Sub 157
TIME IN SESSION: 10:00 a.m. to 1:49 p.m.

BEFORE: Commissioner Daniel G. Clodfelter, Presiding
Chair Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

2018 Biennial Integrated Resource Plans
and Related 2018 REPS Compliance Plans
ORAL ARGUMENT

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P R O C E E D I N G S

COMMISSIONER CLODFELTER: Good morning. Let's come to order, and we'll go on the record. This is in Docket E-100, Sub 157, the Biennial IRP and Related 2018 REPS Compliance Plans by Duke Energy Carolinas and Duke Energy Progress. I'm Commissioner Daniel Clodfelter. I'm presiding this morning. And with me this morning are our Chair Charlotte Mitchell and Commissioners ToNola Brown-Bland, Lyons Gray, Kim Duffley, Jeff Hughes, and I hope you'll welcome our brand newest Commissioner Floyd McKissick who took the oath yesterday, and this is his first time with us on the dais, so we welcome him.

We're going to call, as I say, the Docket in E-100, Sub 157. Let me talk to you a little about this morning and how we're going to proceed this morning, because it's going to be a little bit different than if this were an adjudicative hearing. It is not. So let's be clear about that before we start. Although we will have the court reporter make a record of the proceedings, the primary purpose of that record is not for purposes of evidence or adjudication, but really so that the Commission has a way to go back and refresh our memories about what we heard and what we thought and what we were told this morning. So we will go on the record, but this is not a hearing for adjudicative purposes.

For those of you who were here a couple months back, this hearing will be conducted more like the informational hearing we held on the integrated systems operations planning component of the IRP process. The goal of the hearing is really to enable the Commission to understand a little bit better what's going on in the Integrated Resource Plans by the two Companies, to ask some questions to sort of deepen our understanding, and to flesh out any possible topics or issues that the parties or the Commission might think would warrant a further develop in more formal proceedings at a later time.

So, again, this is an educational presentation and, again, I hope that's the expectation that everyone brings this morning. As a result of that we will not be taking sworn testimony. There will not be cross examination of witnesses or cross examination back and forth or redirect examination by counsel. We did ask that the parties bring with them today subject matter experts and not just chattering lawyers, and I understand they've all done that, being a chattering lawyer myself. But I understand they've done that, and so if you're here in that capacity, we welcome you, but understand that you're not going to be testifying in a formal sense. We're going to be asking you or your counsel or both to present to us in whatever style you may find comfortable.

I want to thank the parties who have responded already in writing to questions presented by the Commission in the August 27, 2019 Order in which we posed a series of written questions to the Company and the other Intervenors in this docket. I want to thank the parties for -- the responses were filed in November on those. Let me say to those of you who have not had a chance to review those yet, there is a wealth of very important and valuable information in them on topics, in addition to those that we'll be talking about this morning. So there are many, many subjects covered in those written materials, in addition to the subjects of load forecasts and reserve margins.

The focus of our presentations this morning will be on load forecast issues and reserve margin issues, and as a result of that we've asked the four parties in the docket who filed written comments on those two issues to present to us this morning. There are other parties in the docket who may have filed comments on other issues. We are not dealing with those other issues today, and that's why we invited these four parties to make presentations this morning.

The Integrated Resource Plans are planning documents that the two regulated Companies prepare. They're for their purposes, and they're used by them for planning purposes, and so we're going to take the presentation this morning in a little slightly different order than we would do in an adjudicative proceeding. We're going to hear first from the commenting parties, including Southern Alliance for Clean Energy and some affiliated parties there, North Carolina Sustainable Energy Association. We'll then hear from the Public Staff, and last of all, we'll hear from the Company. So that's kind of a reverse of the normal order of presentation, but, again, we anticipate that many of the questions we will have will be for the Company predominantly. This is the Company's plan, and so that's really where we need to place the focus.

We've told each of the four presenting parties that you will have up to 30 minutes for your presentations, up to 30 minutes for your presentations. You can do them however you like. If you've got visual materials, we will take those in as additional comment materials. They'll not be evidentiary materials, but we'll take those and put them in the record of the proceeding as if they were supplemental comment matters in response to the Commission's August 27th Order and the November 4th questions.

So if you have written materials of that sort or slide presentations, we'll deal with them in that fashion. We won't have to mark them as formal exhibits, but I will ask you if you're using written materials or presentation slides that we make sure that we get them to the court reporter and we indicate who they're coming from and some sort of title information so she can enter that in the record, and then we'll get it into the docket accordingly.

Questions? Any questions from the participants this morning?

(No response.)

COMMISSIONER CLODFELTER: All right. Let's take appearances first, and then we'll do the ethics reminder. Appearances from the parties, or the participants, I should say.

MS. THOMPSON: Good morning, Commissioner Clodfelter, Chair Mitchell, and members of the Commission. Gudrun Thompson appearing on behalf of Natural Resources Defense Council, Southern Alliance for Clean Energy, and The Sierra Club.

COMMISSIONER CLODFELTER: And am I correct my understanding that you're going to be presenting first?

MS. THOMPSON: That's right, yes.

COMMISSIONER CLODFELTER: Your group of participants will be.

MS. THOMPSON: Yes, sir.

COMMISSIONER CLODFELTER: Great. Great.

MR. LEDFORD: Commissioner Clodfelter, members of the Commission, Peter Ledford with the North Carolina Sustainable Energy Association. With me is my colleague Ben Smith.

MR. DODGE: Good morning, Commissioner Clodfelter, members of the Commission. I'm Tim Dodge with the Public Staff. Also appearing with me today is Lucy Edmondson.

MR. SOMERS: Good morning, Commissioner Clodfelter, members of the Commission. I'm Bo Somers, Deputy General Counsel, on behalf of Duke Energy Carolinas and Duke Energy Progress.

COMMISSIONER CLODFELTER: Thank you. Okay. Before we begin, then, let me, in accordance with the State Government Ethics Act, remind the members of the Commission of our duty to avoid conflicts, and inquire at this time whether any member has a known conflict with respect to the matters before us this morning?

(No response.)

COMMISSIONER CLODFELTER: Madam Court Reporter, please let the record show that no conflicts were identified. And with that, again, Ms. Thompson, we'll turn the floor over to you.

MS. THOMPSON: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Let me say something else, too. We'll probably -- I think we had a little discussion about this yesterday. We'll probably open to questions with each participant after the presentation is made, we'll open for questions from the Commission, but it may be that we may come back, circle back to you later once all presentations are made. We may circle back to a party, a particular party when a particular question has come up in the intervening time, okay?

MS. THOMPSON: Okay.

COMMISSIONER CLODFELTER: Got it.

MS. THOMPSON: Thank you, Commissioner Clodfelter. Thank you. I first want to express my gratitude to the Commission for changing the format a little bit. You'll be glad to know that I'm not going to attempt to orally argue these highly technical issues.

Instead, we have brought our expert James Wilson down. Mr. Wilson was the author of the reports on load forecast and reserve margin issues that were attached to our Initial Comments filed in this docket and -- as well as our comments on the 2016 IRP. So there are some issues that have continued to recur.

So without further ado, I'll ask Mr. Wilson to come up. With the Commission's indulgence, he's -- Mr. Wilson has a presentation. I've also printed out the slides from that and passed those out to the Commission and counsel and Staff. And I'm going to position myself over there so I can operate the PowerPoint.

And Mr. Wilson, if you could just -- if you don't mind introducing yourself to the Commission.

MR. WILSON: Because I'm not testifying, I get to bring supporting materials. Thank you for the opportunity to participate in this meeting. I hope my comments will be helpful.

You can go to the next slide. Gudrun already mentioned that I provided reports in the last two IRPs. I'm an economist. I've been involved in resource adequacy issues for many years, mainly in RTO regions, and I mention two papers from 2010 in the Public Utilities Fortnightly where I raised questions about the one day in 10 years LOLE criterion, and that kind of set some balls rolling. There were a number of other papers sort of on that topic after that, and I think to a great extent the FERC work and the FERC report was sort of a continuation of that topic that got started on the FERC report sites, my work on page 1. So I've been very involved in that all along, and other related work is -- can be found on my website.

So the scope of my comments, I've kind of organized it into three topics, but topic one is the big one and the other two are much smaller, the resource adequacy analysis and the metrics/criteria. So this is question one in the August order and the follow-up questions in the December order. Then topic two is load forecasting and peak load mitigation topics which were your question two. And then topic three, which is also very important, is on work plan in process and that was question 1H in the August Order.

So as a preliminary matter, I kind of like to think of reliability -- we're talking about reliability, resource adequacy here today. I kind of organized it into four broad categories; distribution systems, which is where, you know, most outages that customers see occur; then there's small transmission system, few outages, but they can really big.  And then I've added a new one nowadays -- I didn't used to include this -- system operation.  That would be your problems ramping with variable resources on the system that could potentially lead to an outage.

And then there's resource adequacy.  I'm always trying to take resource adequacy out of the reliability box because it really can and should be supply, demand, prices, price sensitive demand.  We really ought to be able to get to a place where we balance the system with prices and active demand side.  But we're not there, so resource adequacy is often still in that reliability box.

Next slide.  So outage frequency and impact by these four different causes.  Distribution system, small, but many, and it's by two orders of magnitude; it's the greatest cause of outages for customers.

Transmission system can be, you know, we don't want to crash the grid, so we're definitely going to do everything we can there.

System operational, we haven't seen too much of it.  It's increasing.  If it happens, it's probably going to be very small.

And then, of course, resource adequacy, actual, you know, shortages on peak days, we really haven't seen that for a very long time.

And one thing I want to emphasize, and it's perhaps more on the next slide, is that it's a real different type of outage from distribution systems or transmission systems than it is from resource adequacy. When the distribution -- a tree falls or whatever, the customer is suddenly out, he doesn't know when he's going to be back, it could be moments, it could be hours, it could be days.

By contrast, typically, if we actually got to situations where we had to have a resource adequacy caused outage, it would almost certainly be an extremely hot or extremely cold day that was seen days in advance. The utility probably was warning customers we're going to ask you to, you know, conserve energy on that day. They might have even seen it hours in advance. In some utilities you can go online and see whether you're one of the rotating outage blocks and at what time. And then it's a very controlled thing, 30 or 60 minutes, so it's a really -- and it's also kind of directed towards typically the lower impact circuits, you know, typically residential, and avoiding essential use customers. So it's a real different value of lost load impact for resource adequacy than it might be for transmission or distribution systems.

And part of the reason I bring that up is that the Clean Energy Plan calls for doing work on value of lost load related to resilience, okay, and they're going to probably come up with a big number there for resilience. And I just warn you that that number is not the right number to use for resource adequacy analysis, in my opinion. It's a much lower number. A typical -- typically, the number is less than $5,000 per MWh used for resource adequacy.

So next slide. One day in 10 years. Where did this come from? Early 20th century. It's not actually known where it came from. It's extremely conservative. Even before my paper 10 years ago you could find papers decades earlier that suggested this is awfully conservative. Is this really the right criterion? It's not a NERC or FERC requirement to plan for one day in 10 years. Reliability First Corp does require doing a study and for consistency across the regions they say use one day in 10 years and tell us what your reserve margin is, but that's only to do a study. There is not a requirement to build to satisfy one day in 10 years.

So on the next slide -- and this is all in my papers, it's very conservative -- it's about orders of magnitude more delivered reliability. That is at the customer reliability than distribution systems typically deliver. Because one thing we have to remember is when we say one day in 10 years, that's a system event, but only a small fraction of the customers are probably going to have that rotating outage. So for the customer, one day in 10 years is maybe one day in 50 or 100 or some number of years, depending on what fraction of the customer. So that's just -- when I say delivered reliability, that's what I'm talking about, and that's why one day in 10 years is like two orders of magnitude; fewer outages than most customers see from distribution system disruptions.

So, and in my paper I was pointing out that with scarcity pricing that can reach thousands of dollars per MWh and with increasingly active demand-side smart meters, smart devices, and all that, then you really want the system to get to a place where prices are very high and a lot of customers are either knowingly or automatically reducing their load at peak times. And when you actually are in that situation, the distinction between voluntary load drop at a price close to the value of lost load for customers or involuntary load drop, it gets to be very unclear and kind of irrelevant because, you know, if I'm willing to pay 3,000, the price rises to 3,000, if you cut me off before I was about to turn it off, I don't care. It's the same place. But that becomes very problematic for resource adequacy analysis that's focused on calculating physical reliability involuntary load drop. But it gets to be kind of mushy in a world with a lot more demand-side involvement.

So next slide, I like this quote because I think every regulator can relate to it, the things that go bump in night that cause them -- that keeps them awake. This is from Maryland, but I would guess that most regulators feel this way. You know, the most important thing is to keep the lights on. And that's kind of their main charge.

And then the next slide is this economist's perspective on resource adequacy, and this is also on the first page of my paper, is that extremely conservative resource adequacy practices perhaps make more sense to the utility folks and the regulatory responsible folks who will be asked hard questions if they have to have a rotating outage, then it makes for the customer who has to pay for it.

So when trees fall or a line melts in the grid or whatever, you know, that's sort of an external cause.

It's not particularly blood on your hands. But when you just didn't build that extra 500 MW and now you wish you had it one day, well, that's, you know, why didn't you build that extra 500 MW? So I think there's a little bit of a different perspective about resource adequacy, and it's not necessarily consistent, in my opinion, with the interest of the customers. So that's kind of why I throw that out there.

Now getting more specifically to your questions on the next slide. Alternatives to the traditional Loss of Load Expectation in one day in 10 years, LOLH, Loss of Load Hours, and EUE, Expected Unserved Energy, these are also physical reliability measures in that they count outages, either hours or MWh, so they're very similar to LOLE. And typically there's a very simple relationship between them. So if one event -- if a typical event is four hours long and 200 MW deep, then LOLE one day in 10 years would be LOLH four hours in 10 years and EUE 800 MWh in 10 years. Those would all be basically the same, so you could pick any one of those and you'd be in the same place.

Now, over time, as load shapes change and as the resource mix changes, then those ratios might start to shift a little bit. But, you know, when I saw the

FERC report and all this attention to LOLE and EUE and LOLH, I thought, you know, why at the time. I mean, EUE is a better measure. It’s closer to the economics because it's how many MWh got cut off, so it’s, you know, it’s closer to what you really care about because events can be very brief and they can be long, so EUE is probably a better physical reliability measure, but typically there’s a very simple relationship.

Whereas, the last one, Economically Optimal Reserve Margin, you know, that’s sort of the economist’s notion of how you ought to set the reserve margin -- marginal benefit, marginal cost. I mean, for an economist what’s to not like about that?

But the problem with the Economic Optimal Reserve Margin is that to calculate that, you have to really get it right as to what happens on tail events of your load, tail events of your plant availability. That’s just like physical reliability. But in addition to getting all that tail event likelihood and frequency correct, then you’ve got what happens in other situations, the scarcity pricing, the assistance from other regions, if there’s an outage, what’s the value of lost load. There’s all these price and availability assumptions that have to go into it, and for the most part we don’t have any reasonable historical basis to come up with these numbers.

And as you see in Duke’s filing, they point to something from 1982 as the basis, and this is also in the Resource Adequacy study.  1982 is sort of, you know, drives some of the data using that.  So that’s the problem with the Economically Optimal Reserve Margin, is it rests on a lot of assumptions that, you know, are really kind of troubling.

Next page.  The approach used in SERVM, you know, the sort of bathtub curve, U-shaped curve over/under economics that’s been used for a long time, this is from 1978, one of my former employers, Decision Focus, and the Over/Under Model they developed for EPRI. So this conceptual approach has been around for a very long time, but as I mentioned, it does require a lot of very difficult assumptions.

You know, if they’re set in a reasonable manner, an economically optimal reserve margin is always well below the one day in 10 years reserve margin, as in the FERC report, as in ERCOT.  I believe that, you know, if you do right and if you make reasonable assumptions, the economically optimal is multiple percentage points below the very conservative one day in 10 years.

COMMISSIONER CLODFELTER: Well, you know, I had sort of planned to let you get all the way through the presentation, but this is such an important point that I've got to stop here and hear you talk more about it now so we get it clear and focused.

So in the previous slide, though, you were saying the disadvantages and the problems are that we don’t really have good data or ability to model the value of lost load. We don’t have consensuses on how to do that, on what the values should be. The data points are how, then, can we execute this? How do we execute if we don’t have adequate modeling or data capability to come up with the value of lost load? How do we do it?

MR. WILSON: Well, I mean, there is a lot of information on the value of lost load. There are lots of papers. I think the FERC report says for residential customers the consensus is something probably a little less than $5,000 per MWh. So if you’re imagining that a rotating outage is going to be done intelligently and imposed on residential customers, residential communities, because that’s a lower cost of the outage than if you hit commercial or industrial who haven’t voluntarily reduced, then, you know, you pick a number in that range, and 3 or 5,000, it’s probably not hugely sensitive to that. Now, if you put 30,000 in, it probably makes a huge difference. But that's just one of the assumptions.

But, you know, I think if it's done in a fairly balanced way, you have to make up an assumption about scarcity pricing, assistance from other regions, you have to come up with all this, but if it's done in sort of a reasonable, balanced way, then you might get something that, you know, you've got sort of a consensus about and I believe it will be, as I suggested, well under one day in 10 years.

But if you make very conservative assumptions for all those assumptions, a high value of lost load, high scarcity pricing, demand response only at high prices, limited assistance, if you make all those sort of conservative approaches -- and it is common in planning, it's just sort of an instinct in planning exercises to make conservative assumptions, conservative, conservative, conservative -- but if you do that, then you're not trading off marginal benefit, marginal cost, because you've made all these conservative assumptions. The marginal cost of a, you know, combined cycle unit or a peaker, that's something we know real well within, you know, probably 10 or 20 percent.

But the marginal benefit is what depends on all these very difficult assumptions and depending on how you make these assumptions, you can probably get order of magnitude higher or lower. But if it's done in a balanced way, then, you know, you might get something you can agree on, but I do believe it will be well under, not above, the one day in 10 years.

COMMISSIONER CLODFELTER: I shouldn't have interrupted you. I'm sorry.

MR. WILSON: No.

COMMISSIONER CLODFELTER: We'll come back to this topic in the questions, but I should have waited. Sometimes I can't restrain myself.

MR. WILSON: And let's move on. That sort of Number 3 reliability category, I threw in there flexibility ramping with increasing solar penetration and also wind. You need a lot of flexible resources on the system because they can drop off suddenly. That's kind of a new issue. You know, everybody knows California has faced it. You're probably next in line or almost next in line, and that's a big issue. And I guess really what I want to say on that is that the analysis that goes into understanding what the risk is there, what the possibilities are there, and what types of resources you need to be able to be ready for that and provide reliability is so different from what goes into a Resource Adequacy study, which is looking at peak day, that I really encourage you to think of that as a separate issue that requires separate, very focused tools, and not really aspire to stretch the Resource Adequacy study to deal with this. I mean, Brendan Kirby is going to talk about this more, but I really would encourage you to think of this as a separate issue from resource adequacy. Resource adequacy is enough megawatts. This is certain types of megawatts, and not large amounts, but enough so that you can operate the system reliably, given, you know, increasing solar and other penetration.

So next slide is just a few takeaways, and I've already said this. One day in 10 years, I criticized it 10 years ago, and now I'm kind of sitting here saying, well, you know, it's got some advantages because it -- you know, physical reliability, load shapes. We kind of know that. I mean, there's been some issue about winter extreme cold. Plant outage rates, the same thing. We've got a lot of information about that. We're not so sure about winter extreme cold. These are things we know a lot about, and so calculating one day in 10 years or LOLH or EUE physical reliabilities, fairly straightforward, relatively. Economically Optimal is, you know, the right way to go, but -- the conceptually right way, but you've got the question of, you know, all the many assumptions you have to make. So that's mainly what I had to say on that.

A couple other minor points. Communicating resource adequacy needs, in some areas not really here yet, but might be coming, but in other areas they've got like 26 percent winter reserve margins. It's like what? Okay. And the historical traditional reserve margin calculation is an installed capacity number, divided by the forecast or sort of 50/50 median peak load. And both of those aren't really the right -- the best numbers to use for this purpose in the sense that what really helps provide resource adequacy is not the installed capacity, but the unforced capacity, you know, taking into account outage frequencies and the capacity value for variable resources. Sometimes it's called UCAP, Unforced Capacity.

So if you put that in the denominator and then in the numer--- in the numerator, sorry, and in the denominator it's not really the 50/50 load that you're planning for. You're really planning for the extreme peak load. So if you had 90/10 peak load, you know, that peak that you expect to incur once a decade, and some utilities in PJM and others do have that, you know, that's really the number that tells you it's closer to how much capacity you're going to need.

So if you take that unforced capacity, not install the lower number, and you divide it by your 90/10 forecast, then you've got a number that's like just a couple percent of unforced reserve margin over the 90/10. And the advantage of that is it would be much more comparable between regions, and it would also be much more stable over time as the forecast and the resource mix and load shapes change. So I just throw that out there. You might consider asking for that as sort of an additional. An additional traditional IRM you might ask for that as an additional measure, and hopefully it would be much more stable over time.

And then just the last comment on this topic, just to point out that Duke, in its filing, really didn't respond to a number of my criticisms with the RA studies, economic load forecast error I raised issues, the relationship between extreme cold and load, and then the use of the confidence interval and value at risk, and then the lack of sensitivity analysis and such. I'm not going to go into details, but just to point that out for completeness, I guess.

Next topic, much shorter, load forecasting and peak load mitigation. And really this is still about the Resource Adequacy study because what I recommend here is that the load forecasting process and the analysis that goes into it can provide a lot of useful information to guide the Resource Adequacy study. I mean, they already provide the forecasts, of course, the winter -- summer and winter peak load forecasts, but also the RA study wants a load forecast uncertainty error, but the load forecasting effort could come up with a high economic growth scenario. It could tell you kind of how far off they would be if you were surprised by strong economic growth or low efficiency or something like that, and that could help guide what sort of assumptions ought to go into the RA study.

It would be great if the load forecasters could analyze that 90/10 summer and winter peak. That peak, it’s not expected every other year, but once per decade. It would be great if they had that because that would be a very important input to the RA study. Without that, you know, the process of doing the RA study is making up values for things like this that aren’t necessarily consistent with or guided by the load forecasting effort. So that's why I recommend that the load forecasting experts get on this to maintain consistency.

And then the only other point on topic two I wanted to make is which end uses contribute to winter load spikes, and this is one of your questions, of course. And I first point out that Duke's response was five or six pages, but it was mainly citing national and, you know, southeast regional data from EIA and EPRI. Apparently, there's not -- there is still not really very much knowledge about specifically which types of end uses and customers are creating those winter spikes on the Duke system.

The discussion, if you read it, it pretty clearly places the blame on residential customers. In fact, there's no mention of commercial and industrial. And, in fact, it's pretty clearly to blame on rural and lower-income residential customers. And you can see where that goes. That probably, you know, suggests that it might be pretty difficult to be effectively mitigating or shaving those loads.

But I would just call some attention to commercial customers, such as schools, stores, and offices, which when there is really extreme cold, you know, one day in 10 years extreme cold in the forecast, which, of course, in the RA study is extremely important, but when there’s that sort of cold in the forecast, probably a lot of schools and businesses and stores are -- would be thinking about shutting down or opening late anyway, and so maybe the Company can get an agreement that, you know, when the forecast is below whatever for day after tomorrow, you know, you’ll decide to open at 10:00 and you’ll, you know, either prewarm or reduce your energy use until after 9:00 because as you know, that winter spike, that it's very rare and very extreme and very narrowly on the 7:00 and 8:00 a.m. So I just call attention to that possibility as something that’s sort of missing from their filing.

Topic three, the Work Plan in process. The proposed Work Plan in their filing I consider to be flawed. There’s no mention of stakeholder input; only Public Staff. It only calls for updating assumptions. It doesn’t really seem to allow for any reconsideration of any structural or, you know, elements of the approach. It only calls for sensitivity analysis after the validation and simulation and results. In other words, it's just a reporting part of the thing, whereas, you know, I consider sensitivity analysis to be a really critical part of the process all along.

And it also apparently tries to hardwire some controversial assumptions like the three year forward load uncertainty and weather data back to 1980. So it suggests that the only sensitivity analysis will be Company requested, so, you know, there’s some things I note.

And on my next page, you know, I would strongly recommend two main elements of it, which is stakeholder review and input throughout the process. When you get input early on and you get the -- you hear the criticisms, you can respond to them, you can provide analysis, that will mean that after the report goes forward with those assumptions, you know, we already had our chance. It’s already kind of -- you know, it could be a lot quieter after the fact. So I think it can be real important to get that up front and, you know, I think it just improves the quality of the report to hear those criticisms.

I can’t tell you how many times I’ve heard like PJM or ISO New England listen to stakeholders and say we’ll take that back. And then next month on the same topic they’ve done some analysis and either they agree or they disagree, but they’ve got a sound basis for whichever path they're going to go from there. And then that issue kind of is off. You know, that one is taken care of. So stakeholder review and input.

And the other one is sensitivity analysis is so critical. I really recommend that you require providing sensitivity analysis as requested pretty much throughout the process. It's real important early on to identify which assumptions matter and which don't matter. So just to give, you know, one of my favorite examples, we normally think that historical weather data, you know, is something very straightforward, and if you've got 20 years of historical weather data, you've, you know, really got a lot of information about what weather might happen. And if you used 30 or 40 or 50 or 80, you would expect that it wouldn't make any difference, you know. At some point you've got plenty of weather data.

Well, I suspect that in this situation where they use 20 or use 50 makes a difference, you know, results in a different IRM. My filings kind of suggest that. Duke says, well, what's the right number, Jim? And I didn't really have an answer for them, but the first step is sensitivity analysis. It doesn't make any difference. If you get the same reserve margin, whether you use 20, 30, or 50, then we don't need to talk about this anymore. We’re done. We can move on.

But if it makes a difference, you know, if going from 40 to 50, bringing in the 1980s, for instance, makes a big difference, then you've got to ask yourself 1980s, you know, we saw some extreme cold that we haven’t seen since. I mean, I may be talking about a different part of the Southeast, but, you know, do we really assign equal probability to that to what we’ve seen in the last 10 years? You know, it just -- it means there’s an issue that you need to look at. So that’s why sensitivity analysis is so critically important early in the process. And lots and lots of the assumptions that could potentially become controversial if you do sensitivity analysis and show that they don’t matter, then people can stop talking about them and you can move on.

And just as one example of a really good process, you know, PJM updates their reserve requirement study every year. There’s a whole process they follow every year. There’s a resource adequacy analysis subcommittee that meets several times during the year. We can ask for any sensitivity analysis we want and they’ll always do it. Their report includes, I think, if I remember, it's 60-something sensitivity analyses, some of which I requested back in 2010 and lost interest in in

2012, but I never quite suggested that they take them out. Maybe somebody likes them. But, you know, there's a very thorough process to review with stakeholders all the assumptions, any changes to methodology that people might want to raise that PJM is considering and just this whole process.

And then when they publish that report in October, it's usually a really quiet process for it to go through the whole approval process because we've already done it, you know. I mean, maybe I didn't like that or maybe I didn't like that, but the stakeholders discussed it, PJM provided analysis, we went on and, you know, okay, I'm past that now. So I really recommend that you consider, you know, a stakeholder involved process like that.

So next slide, and I'm almost done, model validation. I use the word validation in some of my filings, and when they couldn't provide sensitivity analysis and they couldn't provide model reports and they couldn't provide this and this, I questioned whether they had validated their model because these were things that, in my opinion, you can't validate a model without providing these bits of information.

And Duke's report, Duke's response brings to my attention, okay, validation, that can mean two different things. Software validation, the computer model validation, it reads in all the inputs, it does the calculations it's supposed to do, it creates the summaries and reports, and it does all that correctly. Okay. I accept. I accept that. When I talk about model validation, I mean, you're putting in all these assumptions and you're trying to represent a real world phenomenon that we're concerned about if we don't have enough capacity built.

We've got a lot of assumptions about load and resource outages and neighbors and scarcity and customers, and all that's coming together. That's our model. And validating that takes a lot of looking at just exactly what's happening on these tail events, what all is coming together, how often, how sensitive it is to these various assumptions which matter. It takes a real critical eye. I get the impression that hasn't been done, so I kind of wanted to make that distinction.

And I also want to point out that, you know, there are some places in the report where it seems to suggest that there's so many scenarios, it has to be accurate. Okay. So if I had like a weird, you know, five-sided die with different shaped sides and I wanted to know how frequent is a 1, I could throw it 10 or 20 times and maybe it shows up, you know, 10 percent of the time. That wouldn't be very confident. I could throw it a thousand times, and then maybe I have, you know, 10 -- 100 out of 1,000. If I throw it 1,000,000, I have a pretty good idea of how often that 1 shows up. But that's not true of probabilistic models. Lots and lots of scenarios just means you've got, you know, probability distributions with lots of points on them. It doesn't -- so don't -- just because there's millions of scenarios in there, let's not make -- think of that as like scientific observation.

And then just the last thing, the Clean Energy Plan calls for an iterative and transparent process that involves stakeholder input throughout, and I'd just leave you with that thought. I think that would be a very good thing to do.

And that's my presentation. I hope I didn't go too long.

COMMISSIONER CLODFELTER: Thank you for that. And as I said at the beginning, we will receive your slide deck as additional comment material in the docket, so we'll file them accordingly. We're going to open to Commission questions, and I want to start with just a couple, and then so that I don't dominate it, I'm going to let other people talk then.

But I want to go back to the issue of the economic optimal reserve margin. In the 2016 Resource Adequacy studies that Astrapé did for Duke, they have this, I don't know what you'd call it, crosscheck where they check the LOLE results against what they call the total system energy costs. And as I understand it, that does try to in some way put an economic sort of valuation of some sort on the results, on the calculation. And they say in the 2016 study that it pretty well comes to the same result, that if you use their calculation and computation of total system energy cost, the low point of the bathtub curve is exactly where they calculate it on the physical reliability metric. You want to comment on that?

MR. WILSON: Well --

COMMISSIONER CLODFELTER: How useful is that? What credibility should I give it? What weight should I give it?

MR. WILSON: Yeah.

COMMISSIONER CLODFELTER: How useful is it?

MR. WILSON: Well, what it is, is their economically optimal reserve margin approach in that study comes up with a reserve margin that's, you know, very close to the one day --

COMMISSIONER CLODFELTER: Right.

MR. WILSON: -- in 10 years. And in my filing, I kind of criticize some of the assumptions like the economic load forecast uncertainty and others. But, you know, they've got a very high VOLL number in there. They've got assumptions about demand response and assistance and scarcity pricing that all contribute to assigning very, very high costs to situations not just -- and I note that the VOLL number isn't even very sensitive, because what they have is when capacity is rather tight, you're not having involuntary load drop. You're just having tight capacity. They've got extremely high cost things going on at that time based on all the assumptions that they have made. So, you know, I think they've got thumbs on the scale there, and that's why they get that up to the one in 10 level.

You know, as I suggest, I think that if you put more reasonable numbers on a lot of those assumptions, you get an economically optimal reserve margin that would probably be, you know, two, three, or four more points below the one day in 10 years.

COMMISSIONER CLODFELTER: Let me shift to another topic and then I'll let others talk to you. You opened a topic that I didn't know whether we'd get into this morning, but you have gotten us into it, so I want to explore it just briefly.

From a customer standpoint, an outage is an outage, and I'm not really particularly sensitive to the cause of that. I experience it differently based on the cause. As you explain, an outage that's caused by distribution disruption is going to -- I'm going to experience that differently than a resource adequacy outage, but it's still an outage. And I'm going to have to grapple with an outage and deal with an outage. And I'm going to want to deal with the most important outages to me first. They're my top priority.

So I'm looking at a situation where I can invest limited dollars. Ratepayers have a limited capacity to pay. We have to manage that all the time. There's only so much we can say to them you've got to pay; this is your rate; this is the -- this is the rate we're going to ask you to pay. There's only so much we can ask them to pay. And we can deploy that revenue that's generated by those rates, then, to address the reliability issues in different ways.

One of them is to put those dollars toward resource adequacy. Another one of them is to invest those dollars in improving SAIDI and SAIFI results and reducing distribution system disruptions. That's a reliability issue. The customer says reliability to me is what matters. Reliability is what matters to me. I don't want my power to go off. Multiple causes of that.

So has anybody figured out how to make an effective decision model for saying what resources should optimally be put toward the resource adequacy question as opposed to improving SAIDI and SAIFI? That's really the choice that we're confronted with right now and I expect will be continued in the future. I've got $100 million of ratepayer dollars that I can ask them to pay. Should I put that $100 million on improving SAIDI and SAIFI or increasing -- improving reserve margins? Has anybody figured out a decision-making model for addressing that question?

MR. WILSON: That's a really good way to structure it. I like that. I don't know if I've seen a model that actually tries to make that tradeoff. I mean, in principle, to an economist, you should do the marginal benefit to marginal cost on both of those decisions --

COMMISSIONER CLODFELTER: Right.

MR. WILSON: -- and that will get you to the right point where you're spending your marginal dollar correctly on either one.

I do want to dispute a little bit in outages and outage --

COMMISSIONER CLODFELTER: Well --

MR. WILSON: -- because, you know, the distribution system outage, you don't know whether you're going to be back in a moment --

COMMISSIONER CLODFELTER: Right.

MR. WILSON: -- or in 10 minutes or in an hour or two weeks sometimes.

COMMISSIONER CLODFELTER: As I experience it, it is more disruptive, yes.

MR. WILSON: Yeah.

COMMISSIONER CLODFELTER: As a customer --

MR. WILSON: Right.

COMMISSIONER CLODFELTER: -- it is more disruptive, yes.

MR. WILSON: Whereas the rotating outage on the extremely cold or hot day, you may actually have been warned the day before that this might happen, and you may be able to go online and say, oh, geez, I'm, you know, 7:00 to 7:30. You know, it can be a lot less disruptive.

But that is the way to think of it, and I think you'll find that, you know, for a lot of customers that marginal dollar is much better spent on the distribution system than on, you know, driving the incredibly unlikely of one day in 10 years even lower.

COMMISSIONER CLODFELTER: Well, I hear you. You know what I'm searching for. If you come across anything really good in the literature or you develop it yourself or you know somebody else has developed it and wants to win a prize for it, you know, we're open for business. We'd like to receive it. But, again, it's a difficult task, and what you're telling us this morning is that we're being -- your position is we're being overly conservative, the Companies are being overly conservative about how they value, in effect, resource adequacy.

And so what I'm sitting here saying is uh-oh, how do I explain to a customer that I'm putting those dollars into resource adequacy when what the customer really wants me to do is to deal with vegetation management and other distribution system related disruptions and keep the power on --

MR. WILSON: Yeah.

COMMISSIONER CLODFELTER: -- at the distribution level. How do translate that? That's what

I'm looking for.

I'm going to stop with that and see what other topics others want to explore with you. So other Commissioners? I've got other questions for you, but let's see if other Commissioners do. Nobody? All right. Wow!

All right. The point on slide 13 that you've got about the flexibility in ramping reserves, I'm going to ask you to comment on this issue that we're sort of addressing here, and then I'm going to ask it of you because it saves me time asking it of the Company later because I'm going to want the Company to talk about it, too.

So we've just gone through a proceeding here in which we have dealt with the issue of how we have solar penetration in North Carolina utilities' territories is causing a change in reserve requirements, operating reserve requirements, and we've established certain ways that we're going to deal with that through our avoided cost pricing for projects that are interconnecting to the grid. In the course of that exercise we've sort of modeled, or the Companies have modeled what additional operating reserves they do expect to have to put online and to maintain in order to accommodate various levels of solar penetration in their systems.

So I then read the Resource Adequacy study, the 2016 Resource Adequacy study, and what I understand is -- and, again, I'm asking of you, but I'm going to try to get Mr. Wintermantel and Mr. Snider to tell me if I'm not getting it right, and then to comment on it -- is what I understand is that when the Company is looking at resource adequacy, an embedded component of that starts off with minimum operating reserves. That's taken as a fixed input, and then you build off of that to try to see what else you need for resource adequacy. Well, operationally, though, am I right operationally when you're facing an extreme event, when we come to a point of an extreme event, weather or some sort of unplanned outage or a combination of all those things, the first thing that's going to happen, there's not going to be a load shed. The first thing that's going to happen is you're going to be starting to shave the operating reserves. Am I correct about that?

MR. WILSON: Yes.

COMMISSIONER CLODFELTER: And so as you begin to run down the operating reserves, you know, you're under your target reserve margin, but you haven't yet had to shed load because you're using up your operating reserves. And so I'm thinking about the fact that we're now experiencing levels of solar penetration that are causing us to increase operating reserves. Well, why does that matter? Why does that matter to me? Because the peaks -- it matters because the peaks that our utilities are experiencing are winter peaks, the early morning winter peaks, and during those early morning winter peaks I'm not managing flexibility and ramping problems from solar penetration. Solar is not on the grid. The sun is not even out yet. So I've got more reserve margins now in my system that I can manage to avoid load shed. And so it seems to me like that's become an advantage for me now. I can sort of treat that as almost like free reserves for capacity planning purposes -- for capacity planning purposes. I look at that as sort of like found money. Am I looking at it the wrong way?

MR. WILSON: Well, I mean, the reserve -- the planning reserve margin is driven by the summer and winter peak loads.

COMMISSIONER CLODFELTER: Sure.

MR. WILSON: It doesn't really have to do with how much operating reserve you have to have mobilized during a time of year. What is it, you know, April or

May or, you know, afternoons when the solar might drop off suddenly? That's operating reserve. That's different from the planning reserves. That's just some of those capacity that you have on the system has to actually be ready to respond at that time, but -- so those are really kind of very separable.

But I agree with you, and I actually argued this, that on that extreme winter peak you probably don't need for that very brief period very much operating reserve because you know that load is going to drop very quickly, and I kind of suggested that at least as I understood from certain documentation, that they were assuming that they would hold a lot of operating reserve right through that very sharp winter peak, and that led to load loss and raised a winter reserve margin. That was my impression, what they did. So that's another assumption that merits some attention this time around.

COMMISSIONER CLODFELTER: So it does connect? It connects in the way you just articulated.

MR. WILSON: That's how it -- that's how it connects.

COMMISSIONER CLODFELTER: Okay. All right. Well, I --

MR. WILSON: It seems reasonable that you would be willing to go a little -- I mean, there's a minimum operating reserve so that you are ready to not crash the transmission grid --

COMMISSIONER CLODFELTER: Right.

MR. WILSON: -- if you lose, you know --

COMMISSIONER CLODFELTER: Right.

MR. WILSON: -- your n minus 1, whatever, n minus 2, whatever. You know, there's that. And you're going to maintain that minimum operating reserve under all circumstances in order to be transmission reliable. But that's probably less than the amount, the full amount that you normally want. I agree.

COMMISSIONER CLODFELTER: Okay. In your -- when you began, you indicated that a great deal of your experience was with market systems that are participating in markets, organized markets.

MR. WILSON: Yes.

COMMISSIONER CLODFELTER: We are not, of course.

MR. WILSON: No.

COMMISSIONER CLODFELTER: And so we have to manage this issue through resource adequacy. We don't really have the opportunity to go out and have supply and demand managed through the market. We manage it through the resource adequacy determination in the Company's planning. So how do we need to look at the -- any of the issues you've described differently, given the fact that we're not in an organized market? I mean, do we have really the ability to usefully generate an economically optimal reserve margin type of product in North Carolina? Can we really usefully engage in that exercise, given that we don't really have some of the pricing tools available to us that they have in organized markets?

MR. WILSON: Yeah. That's a good question. And I do have to remind myself frequently, oh, yeah, this is one of those areas, not one of these areas. And on that extreme, especially on a summer extreme peak day, there is a lot of market stuff going on, you know, between you and neighboring regions, and merchant generation that's available and demand response and price response of demand. There's still hopefully a lot of market stuff going on at those times that can help you out a lot if the prevailing prices on the eastern interconnect are going up, at least locally or a broader area.

But that is an issue, that you're not fully making use of how prices can help you in peak periods. And that, of course, can be augmented with programs like

Critical Peak Pricing and that sort of thing that can be very helpful, but it is a different situation.

In terms of the economically optimal reserve margin, and that’s another thing that I probably -- I mean, I sort of dismissed that in the RA studies, so I didn’t drill down on them real hard, but, you know, you are hedged to a very great extent under these circumstances, so you need to think a little more about exactly what are those costs and are they really costs or are they transfer payments because transfer payments look like a cost to whoever is paying them, but somebody on the other side is receiving that, making a profit, and that can get them to respond.

And I did make that point just to sort of criticize the notion that you ought to not only do economic optimal, but you ought to, you know, do a confidence interval because, you know, if you’re under those extreme situations, paying a lot of money to some merchant plants, you know, your ratepayers are paying this money and those merchant plants are doing great. Yes. Right now that’s money spent. That’s cost. Those merchant plants, they made a profit, they’re encouraged, they’re incented. Somebody else is going to build another merchant plant. I mean, that has indirect positive impacts on the market and on customers. So, you know, you kind of need to take that into account.

If you really did a society optimal view, then those transfer payments are not cost. Those are -- you know, you recognize that they're -- they went to somebody. They're not really cost.

So it's tricky in a vertically integrated area to do the economically optimal, and it does raise some additional issues.

COMMISSIONER CLODFELTER: Are there some states we should look to that have had some success with looking at the economically optimized model that are vertically integrated outside an organized market?

MR. WILSON: I'm not aware of a place I'd point to and say, yeah, do it like them. I can't --

COMMISSIONER CLODFELTER: Anybody that's attempted it that we ought to look at --

MR. WILSON: Well, I think --

COMMISSIONER CLODFELTER: -- and learn lessons from?

MR. WILSON: Yeah. I mean, I think other states in the Southeast are doing similar sorts of things.

COMMISSIONER CLODFELTER: Okay. Anything else from the Commission?

CHAIR MITCHELL: Just a quick question for you. You made the point about winter load spikes and the state of knowledge at this point in time about which customers and end users are causing or contributing to those spikes. Can you talk a little bit about that? What is known at this point, and if it’s very little, why is that?

MR. WILSON: Yeah. You know, I can't talk because we don’t know. I was a little disappointed by the Duke Companies' response this time around. You know, it just seems like there should be more research going on to find out, you know, what -- it doesn’t even say what is the customer mix under that peak load. You know, I accept, as I suggest, that it’s probably heavily residential, but there’s probably commercial and industrial in there. They’ve got a lot of load data, you know, from those times, and so I really think it’s important to do some more research about that.

You know, they’re relying on this sort of national and regional data, so I think I can’t speak to that, but I think it’s something that really warrants a lot of research because a very, very rare, very extreme winter load spike, to me, that cries out for something to mitigate, not something to build an additional power plant to serve. You know, it just seems like it should be something you should be able to mitigate and, therefore, not have to plan generating capacity to serve it.

COMMISSIONER CLODFELTER: Thank you very much.

COMMISSIONER DUFFLEY: I've got a few.

COMMISSIONER CLODFELTER: I’m sorry. Commissioner Duffley.

COMMISSIONER DUFFLEY: So I’m on slide 16, and you mention Duke has not responded to my criticisms of Resource Adequacy study, and the first one is the economic load forecast error. I know that within PJM that they had -- they were -- had forecasting errors that they have resolved. How did they resolve those? Can you remind the Commission, how did they resolve their load forecasting problems?

MR. WILSON: Okay. Two issues. One is PJM’s load forecast over a decade have been -- you know, they’ve been over-forecasting like almost everybody has, and they’ve changed their methodology multiple times, and in some of those iterations I’ve said, you know, wow, I think you’re close now, and then they’ve gone and done additional work. I wouldn’t say that they have, you know, resolved their load forecasting errors. Their current -- they made a big change to their methodology and they get kind of similar results. To me, it still looks like they're over-forecasting significantly, so --

I mean, the most important thing nowadays, in my opinion, is to use a historical period that is post-recession, and I think the Duke companies are doing this and other companies are doing this. And if you do your load forecasting based on it's now 10 years of post-recession history, that history, almost everywhere the peak loads have been moving in a kind of a straight line, and the economic growth has been pretty steady, and the demographic, all those things are kind of, you know, moving in directions and aren't expected to change a lot, it makes for a forecast that's, you know, look at that and it's kind of more of the same and it's sort of reasonable. So that's on load forecasting and errors.

And then there's the issue that in the RA study they use an assumption for load forecast uncertainty. They add, you know, a scenario where loads just like grow way faster than according to the forecast. Now, that's what I have criticized. And in the study they took GDP forecasting errors and used U.S. GDP forecasting errors and translated that into an assumption about Duke company electric peak load forecasting errors. That's kind of what I criticized because I thought it was excessive. And, you know, that's where I think the load forecasters, by perhaps running a high economic growth model based on all of the assumptions that go into that and running it through their economic model and seeing what does that do to our future peak loads, I think that would be a better way to come up with a reasonable assumption for how peak loads might grow a lot faster than anticipated. So that's the two parts of your question.

COMMISSIONER CLODFELTER: Anything else?

(No response.)

COMMISSIONER CLODFELTER: Thank you, Mr. Wilson.

MR. WILSON: Thank you.

COMMISSIONER CLODFELTER: Ms. Thompson, anything else?

MS. THOMPSON: No. Thank you, Commissioner Clodfelter. Mr. Wilson will remain in the hearing room and is available for any follow-up questions.

COMMISSIONER CLODFELTER: Great. Thank you. Mr. Ledford, we're with you.

MR. LEDFORD: Thank you, Commissioner Clodfelter. I would like to introduce Brendan Kirby who will be presenting on behalf of NCSEA. We will be momentarily distributing Mr. Kirby's presentation, as well as his bio and other relevant materials. Mr. Kirby, when you're situated, would you mind introducing yourself to the Commission?

MR. KIRBY: Good morning, Commissioners. Thank you for the opportunity to be here. I'm Brendan Kirby. I'm retired from the Oakridge National Lab and I'm now a private consultant. Please forgive me. I'm getting over a cough, so I've got a lozenge and a little bit of water.

There is a full bio -- not a full bio -- there's a short bio in the handout. I guess we'll get the slides in a second. And so what I'm going to talk to you about is you put out an Order December 23rd asking about our reactions to "Resource Adequacy Requirements: Reliability and Economic Implications" study that was done by the Brattle Group and Astrapé for FERC, and you had three questions with that, so I'm responding to that.

The three questions were the changes in the treatment of the reserve margin in the IRP, also in the metrics involved in looking at reserve margins, and then risks and cost to mitigate.

Slide three. I like the report. I think it's an excellent report. What I really like, it's got very good narrative, explanations of issues. It talks about both sides of an issue. And then it has a nice example system, so it shows numeric trends. And it also shows the tools, the data required, how to do the analysis, and -- but I really like the report.

And by the way, please interrupt with questions anytime. That probably is more productive.

So slide four. So the second question first because it’s the easiest. Is Expected Unserved Energy, it’s a much better metric than LOLE. Reason is, as Jim was saying, LOLE just counts events. EUE gives you some sense for how big were the events, so what’s the total customer impact? It’s a better metric. It's not an absolute. It’s good actually to see multiple metrics, but EUE is a better metric. The metric should reflect the impact of the length of the outage, the number in the outage, and the durations of -- and the depths of the outages.

The LOLH, the number of hours, that’s a little bit of improvement. EUE is also normalized, so it’s done as a percentage. So if you come out and say I want an LOLE of .11 one in 10 years and you apply that same metric to PJM, which is 150,000 MW, and you apply that same metric to the Turlock Irrigation District, which is

500 MW, they both achieve the same metric; it's a very different impact on their customers. So you want a metric that's also normalized. And the fortunate thing now is that the computing capability or analysis tools were no longer limited. You know, we can do the EUE calculation. We can do all the calculations.

And slide five. So as Jim said, these metrics are not directly compatible or comparable. It's not like changing between miles per hour and kilometers per hour where it's a different number, same exact thing you're measuring, so -- and that's something -- just means you got to be careful. It doesn't mean you shouldn't do it. Just you need to be careful.

So the trends, though, on all three metrics, they do tend to be the same. And for any specific case you can come up with -- you can come up with a specific LOLE number, LOLH number, and EUE number that are the same, but it's only the same for that case. So you have to be careful --

COMMISSIONER CLODFELTER: What's a case? What constitutes a case?

MR. KIRBY: Well, so for --

COMMISSIONER CLODFELTER: Is that a resource portfolio mix or is it something else?

MR. KIRBY: Well, a resource portfolio mix, a specific weather year.

COMMISSIONER CLODFELTER: Right.

MR. KIRBY: So in slide six we finally get to a picture, so all three metrics have the same kind of impact. You know, the higher the reserve margin, the increased reserves, you're going to increase reliability. You're also going to increase cost. So all three of the metrics do that, give you that same impact.

It gets more interesting, though, on slide seven. So when you look at LOLE, one of its problems is, you know, one in 10. Well, what is that? Is that one event in 10 years or one day in 10 years? And even if you say it's one event in 10 years, you have the problem that there is not industry consistency on what exactly does that mean. So what this curve is showing, in the very lightest curve, the highest curve, light blue, that's counting -- so that's showing reserve margin that's required to hit a specific LOLE. And it takes a lot more -- it takes a lot higher reserve margin to hit a .1 LOLE if you're defining the event as you've just run out of operating reserves.

Alternatively, you can -- as others say no, I'll allow you to deplete the operating reserves. What I care about is have I had to go into a voltage reduction? Have I taken an operating practice of I've had to reduce voltage in order to maintain reliability?

And then the lowest line is the one that says, no, I'm going to allow it to, you know, the one in 10, fully deplete my reserves, fully utilize all of my operating practices, and I'm actually to the point where I've got to shed firm load. And, you know, so that gives you -- that says that the reserves you require depends on exactly how you define the LOLE event. I would argue that the reserve requirements, they should be -- they should be based on mandatory NERC reliability standards, so you should base what you require on this one in 10 or whatever your metric is on what are the things that NERC says you have to do? What are the standards required?

Also, as Jim very much pointed out, in actual operations, this loss of load due to a lack of capacity is extraordinarily rare. In actual operations there's an awful lot of things you can do that prevent that actual event happening. The report itself notes that resource adequacy related reliability events account for a very small fraction of customer outages. So that goes back to your question, Commissioner Clodfelter, that if you've got -- it's a marginal cost type issue. Where do I spend my next dollar? What is going to give me the most impact?

So the -- slide eight. The fact that the reliability events are very rare has got very important consequences. Do thousands of cases of simulated. These reliability metrics, they're driven by a small number of the cases. So in the example system, 45 percent of all years have no outages at all. One year has got 68 load shed hours. Then you look at the -- when they were -- when you shoot for a 2.4 loss of load hours per year, which comes into -- it looks at an LOLE based on one day in 10 years, all right, 10 percent of the years exceeded the 2.4, but when they did 9,600 cases, the probability weighted average is still 1.4. So that's telling you that the reliability analysis is driven by a small number of years, a small number of hours, a small number of conditions.

I'm going to get -- take a side step a little bit, but we're going to get back into the fact that it's really a question of risk aversion rather than risk mitigation, or it's a variability volatility aversion as opposed to say necessarily completely risk mitigation. It's more than -- it becomes more than an economic question, and that's a place where things get different and interesting.

So the report does a really nice job of discussing how to set reserve margins to minimize cost, and then does a really nice job of talking about how you can balance those costs against what your risk aversion is. So this curve, this graph is doing -- it's really nice. It's -- again, it's showing the reserve margin across the horizontal axis and the reliability related cost on the vertical axis. And so the obvious thing you want to do is minimize your total cost. Okay. So that's straightforward. You look for the bottom of the curve. That's great.

The thing that to me is very interesting here is what you see is the shift in where the costs come from. So on the left, very low reserve margins. The place you start incurring cost is in load shed events, voltage reduction events, operating reserve shortage, emergency demand response. You're seeing a lot of cost coming at the top of the set of bars that are impacts on things happening to customers.

You move over to the right and they completely disappear. You're not seeing any load shedding, no voltage reduction, no operating reserve shortfalls. What you're seeing is the cost come in because you're spending more on capital cost for generation and operating cost on generators. So you're doing that tradeoff of saying, well, I'm going to spend more on more iron in the ground and more fuel, and then I won't have -- I'll reduce the things like voltage reductions, even the exercising of my demand response. And demand response, remember, is folks who volunteered to respond. So it's a resource to use, but there is a cost associated with it. Okay.

And as Jim said, very important, the quantifying -- the cost for these customers' cost, those are tough. We don't have -- just repeating, we know what the cost of a combustion turbine is. We know what the cost to operate it is, what the cost to buy it is. We don't really know what the cost is when a customer is shed for an hour.

We do get a little bit lucky. It turns out the -- we know the cost is high, so is it $1,000 MW? 5,000? 10,000? So we know it's high, so that's good. It also turns out because it's high and it is so much higher than the cost of generation, when you go through the modeling, the modeling is somewhat insensitive to that cost. You don't need to know with near as much precision what the cost to a load is the way you need to know what the cost to a generator is, so we do get a little bit lucky there.

Yeah. The reports notes that resource adequacy related reliability events account for only, again, only a very small fraction of the customer outages. So even with this, where we're talking about cost to customers for outages, this is only the outages that are due to the resource adequacy question.

COMMISSIONER CLODFELTER: Stop just a minute.

MR. KIRBY: Yes.

COMMISSIONER CLODFELTER: I want to be sure I understood what you just said to us, is that the value of lost load is a relatively important -- unimportant variable with how we --

MR. KIRBY: Yes.

COMMISSIONER CLODFELTER: -- where we set that value.

MR. KIRBY: Yes.

COMMISSIONER CLODFELTER: Where we set that value is a fairly unimportant variable for this purpose?

MR. KIRBY: Yeah. And I don't want to -- my point is you don't need near the precision you would have on what's the fuel cost for a combustion turbine.

COMMISSIONER CLODFELTER: Okay.

MR. KIRBY: You know, a small shift changes it, so you can --

COMMISSIONER CLODFELTER: All right.

MR. KIRBY: -- you need to know it, but you don't have to be so precise.

And slide 10 -- and forgive me for this. This is a National Lab slide. We pack lots of words that you can't possibly read, and so I apologize for it. It's my upbringing.

What I went and did here, though, you can read them later, I was quoting from the report, so I wanted to actually pull the pieces out from the FERC report and so you can look at the actual words. The concept is really interesting and much more straightforward. Okay.

So most of the years -- as I said before, most of the years of all these studies have very small reliability costs. Small number of years, big cost. That's one point.

Second point, so the average cost change relatively little, but the uncertainty really grows. Okay. What is that saying? That's saying when we look at the curve over on the right, it's looking at the reserve margin, and over on the left, the vertical axis, it's looking at the reliability cost. Okay. And so we see is on average, right, the reserve -- the cost of higher reserve -- the cost associated with reserves pretty flat; not a lot of difference. It is rising. More and more reserves, it's going up. So in this case the economic optimum reserve is in the 10 percent range.

But then you say, well, what if I look at the 85th percentile, the 90th percentile, the 95th percentile? If I care about what's going to happen to me one year out of 10 and say, wow, high cost one year out of 10, that's really bad, I don't want to be exposed to high cost one year out of 10, well, then you're on the top curve, and then you're seeing that wow, no, the economic optimum -- if the economic optimum for that one in 10 year, that drives your reserve margins way up.

What this says to me is that it's not really risk because one in 10, we're talking about a lot of years. We're not just going to -- we're not just going to live with the system for one year. We're going to live with it for 20, 30, 50 years, right? So a one in 10, it's just a question of volatility, not of risk.

I buy insurance for my house for fire insurance for my house. I hope I will never have a fire and I will never -- so that's all wasted money. I'm happy to pay it. I pay it every year because that risk -- the consequence of the risk is very high, probability is very low. But in that case it's an actual insurance policy where I hate tempting fate, I will never see the fire, so I will never actually incur the cost. Still paying my insurance premium.

This is a case of one in 10, so the prices go up and down, up and down. So am I worried about the risk of that event or am I just worried about the volatility? So do I not want to see that price spike every 10 years or do I -- or is it something that it's, you know, a one-in-a-thousand-year event where with luck I would never see it at all? All right.

So -- but this is a question that -- well, let's take the next slide, slide 11. We'll look at some of the details. So on that example, the risk neutral optimal reserve margin is 10.3, 10.3 percent. If you wanted to go for --

COMMISSIONER CLODFELTER: For whom? Is that a Duke specific calculation you've done?

MR. KIRBY: No, no, no, no. This is --

COMMISSIONER CLODFELTER: All right.

MR. KIRBY: -- this example --

COMMISSIONER CLODFELTER: Exactly.

MR. KIRBY: Exactly. This is the example that Astrapé and Brattle did for FERC --

COMMISSIONER CLODFELTER: Okay.

MR. KIRBY: -- with a nice example system.

COMMISSIONER CLODFELTER: You're still in the FERC setting?

MR. KIRBY: The whole presentation is --

COMMISSIONER CLODFELTER: Okay.

MR. KIRBY: -- because I like the report. I thought it was a great report.

So in this case 10.3 is the risk neutral optimal; 15.2 is -- hits an LOLE of .1. All right. So what it's also saying is if I look at that 90th percentile cost, right, to reduce that 90th percentile cost it takes me 270 million is what I save in that bad year, that bad year when the cost went up. All right? If I go for the one in 20, the 95th, it's 630 million.

COMMISSIONER CLODFELTER: Right.

MR. KIRBY: But what the report concludes is that somebody who was going to use the economic optimal of the 10.3 --

COMMISSIONER CLODFELTER: All right.

MR. KIRBY: -- they will go for the 10.3. Somebody who's -- and they will incur or they will save -- I'm sorry, I'm tripping over my own numbers or the report's numbers. So what I save by going to the 10.3 over 15.2, every single year I save $90 million. So customers save $90 million. What they have the risk of is that every 10 years they see a $270 million cost, and every 20 years they see a 630, but they're saving the 90 million every year.

So what the report concludes, and they do a very nice discussion, they say if you're looking at the economic optimal rate, you're going to go down to the 10.3. If you're a little bit risk averse, you don't want your customers to see the volatility, then you might go with a 15.2. Some commissions might choose to go even higher. Okay. So it's a volatility aversion, and it's a choice the Commission needs to make. Very good.

We go on to 12, slide 12, and here to me is a difference. The economic is an important distinction. $90 million is not zero. The report did also note that that, you know, that 90 million, 270, 630 all sounded like very big numbers for the -- in the example for the customers. It turned out to be a $1.63 per MW kind of premium that they paid to avoid the volatility. All right. Well, $1.63 a MWh, not so much, you know, so maybe it's a reasonable -- it can be a reasonable choice for a commission to make to reduce the volatility, but it's more than an economic question.

The FERC report had very low renewables. Had a little of wind, but very low renewables. So the place it becomes even more than the economics -- and the economics are important, but that's something you're used to dealing with to making that tradeoff for customers. The thing that makes it more than an economic question is that as you go to the higher reserves, you are also shifting the resource mix. It's moving into more and more thermal generation, more and more iron in the ground that is using a physical resource to mitigate the volatility which has a cost to it. And if it's just a cost, that's just a straight economic choice. Here it's also a shift, saying as you put more and more of the thermal resources in, it ends up being less and less for the renewables. So it appears to -- what that translates into is it appears to change the assigned capacity value for the renewable resources.

So my argument would be that self-insuring may be against volatility, against cost price volatility, may be a reasonable economic choice when you also consider the other impacts in addition to the straight economics of volatility.

The FERC report also did a very nice job of pointing out that there are -- and Jim spoke to this as well -- that much of the weather risk can be mitigated through other instruments. You can hedge for it. So you can do forward contracting. You can see things coming and do some hedging against those extreme risks.

Slide 13 had what I thought was just fascinating. I've done a lot of work with demand response, especially demand response for ancillary services, looking at a host of demand response to provide spinning reserve, regulation, the really fast reliability services. At the lab I did work with that everywhere from home air conditioning up to aluminum smelting plants. It is amazing what you can extract out of demand response. It's amazing what a reliability resource that can be, and it's good to see it's slowly coming along, but it's slow.

And I was really taken aback with the report saying that the -- as they looked at higher and higher demand response, it resulted in increased energy prices and increased energy price volatility. That kind of shocked me. I said that can't be right. Demand response is a very good thing. It doesn't do bad things like increase price volatility. And so I studied it, but I hadn't been looking at that. I looked at the technical capability and what it takes to make the resource work and whether the resource makes sense.

The report also looked at did the resource make economic sense and says, yes, it makes economic sense, but it will increase volatility. Well, the more I looked at it, I said they're right, son of a gun, especially based on the assumptions they put in there because of the high cost that gets assigned to demand response. And certainly true, you can interrupt a customer's load, that's more than just the price of energy. So as they looked at very high costs assigned to that demand response, it ends up and you rely more and more on it, it brings down your average cost, it does bring up your volatility, your price volatility. Okay. So you have to be willing to tolerate some more volatility in a price, but you're still saving money. You're still saving resources, so --

So lastly, hitting the conclusions, and you've not done a very good job of interrupting with questions, I must say. You need to --

COMMISSIONER CLODFELTER: It may be because your slides are rather clear.

MR. KIRBY: Very good. Thank you. So my conclusions were that the -- I really like the Astrapé report, the Brattle Group FERC report, very much like it. Good discussion. Great report for looking -- for understanding the issues.

The simple answer is, is EUE better? Yeah, it's a better metric. The more important point to that, and Jim touched on it as well, quantifying the customer cost. Once you've done that and you're looking at quantifying customer cost, you're no longer stuck with picking a specific LOLE number as that's my -- that turns into my reserve requirement. You can now economically optimize your reserves. You can now look at it as a genuine optimization problem.

Now, it's very important to do it right. It's very easy to do it wrong. Very important to do it right. One thing you should definitely look at is make sure that the way that the modeling is done, that the reliability requirements are tied back to NERC -- actual NERC reliability rule requirements.

Stakeholder involvement also very important. Get the stakeholders in so that they agree on what all the assumptions are. What are the -- what is the right way to look at how to do the modeling? All right.

And then lastly, so setting the reserve margins, it's now more complex. So moving to an economic optimization is a very good step, but there's also then the important additional complexity the Commission has to deal with, where I would argue you need to look at not only -- not only risk -- don't confuse risk with volatility -- and then also look at the other consequences of -- mitigating cost volatility is a good thing, but if it has high dollar cost, you have to look at that. And if it has other consequences, you have to look at that tradeoff. That was all I had.

COMMISSIONER CLODFELTER: Let me open with a question that I'm going to -- I didn't ask Mr. Wilson because he had it already in his slide presentation, so I didn't need to ask it, but I'm going to ask it of you and then of all the subsequent presenters. So the Companies are right now engaged in updating the 2016 Resource Adequacy study, and so the question really to you, Mr. Wilson addressed it, and I'll ask the Public Staff and the Company to address it, is there anything useful that the Commission could do in terms of providing guidance, insight, advice, direction in terms of how that Resource Adequacy study is updated? Are there things the Commission should avoid doing? Are there currently conflicting signals the Commission is giving that need to be cleaned up, cleared up, and remove the inconsistency? Is there anything useful, in effect, that the Commission could or should do in respect to the ongoing work that the Companies are doing to update that Resource Adequacy study? If so, what?

MR. KIRBY: Yes, I think there are. And I think looking at -- I think the Commission can look at the process. And so one thing I'd really encourage is open the process up to stakeholder input early on so that looking at things like the assumptions -- assumptions on -- well, on values, things like, as we said, you know, what are the values to use for the -- that you assign for the cost of customer interruptions? So that's good -- because we don't know the exact, it's good to get consensus on it.

COMMISSIONER CLODFELTER: Well, let me stop you there because -- I appreciate where you're heading, but let me stop you there and just sort of pose the question that surfaced I think somewhat during the prior presentation, and that is we're told that we may need more data first. Seems to me that stakeholder process has never worked very well when you don't have your data. And, for example, one example we were told by Mr. Wilson was that we may need more information about what are the drivers, the exact drivers of peak winter demand events? If we don't have that, it really seems to be premature to get a lot of stakeholder involvement. Would you comment on that?

MR. KIRBY: I would both agree and disagree with it. I think it's very true. And, you know, being a lab guy, a research guy, we always need to study more. That's a guaranteed in the answer. And you have to temper that with, okay, the process will always -- we always want to improve the process, and the process has been improving dramatically, so that's good. We are seeing -- the tools we have now versus five years ago are just dramatically better, the computing power and the analysis tool.

But you also, you've got to make a decision. So you say all right, within that we want to get as good data as we can, and then within that we can look at the data we have, that maybe we haven't pulled it all out and laid it all out for discussion, but to some extent, you know, do we really need to go back and do a massive DOE study on exactly what is the cost to each type of residential customer if their lights are out for 10 minutes, 30 minutes, an hour and a half? You know, that's a great National Lab study, but it's going to take too long. So say, all right, given that we're not going to be able to do that, what should we assume? And that's a place that you have to parse between what is it that we can pull data in and enlighten with data and what is it that we just have to say, all right, this is what we've got, let's move forward?

And I think this is one of the areas where that specific question -- and sensitivity analysis is a great, you know, great thing you can go and do, is you say, fine, I don't know what the number is; I'll try it at 5,000, 10,000, and $20,000 a MWh is my cost. What difference does it make? You run a couple of cases of sensitivity and you see that either it's very important or it's not. And then it will tend to have the stakeholders be able to say, okay, that's fine; we'll pick a reasonable value and we'll move forward.

But beyond just -- also, it's the question of how should the analysis be done? So should the analysis be looking at the risk-neutral economic optimization or should the analysis be looking at the 95 percent confidence interval? And that can sound like, well, gee, you know, I'd like to have higher confidence. Well, you want to look at, well, here are the consequences of that decision and then make that decision only once you understand that, and then to get the buy-in.

It's certainly -- as a system operator, you know, I always want to have -- I'm very risk averse.

People like saving money, but blackouts get headlines, so I will always avoid a blackout, and rightly so. We do not want to change that mindset. When we're doing this type of analysis, we do want to look at and say that, well, but some of these tools, the demand response, the emergency demand response and the economic demand response, they're resources to use. It's the Commission's job to make sure that the customers who volunteer for, say, emergency demand response, that they don't get abused, which is the reason you put limits on you can only interrupt them so many times a year, so many, you know -- because it looks like a zero-cost resource when you go to deploy it.

Well, it doesn't look like a zero-cost resource when we do it in the modeling, and it's not a zero-cost resource. To a system operator it looks like a zero-cost resource. And so you have to put constraints on so that it does not get overly used.

But anyway, those sorts of things of what should go into the modeling, that should be agree to up front and it makes doing the modeling and accepting the results much easier.

COMMISSIONER CLODFELTER: Thank you. Let's see if other Commissioners -- Commissioner Duffley?

COMMISSIONER DUFFLEY: On page 11 of your slide deck you talk about the report's conclusions.

MR. KIRBY: Yes.

COMMISSIONER DUFFLEY: And you have it broken down into groups a), b), and c), the risk neutral policy, and then risk-averse policy maker and highly risk-averse policy maker. Currently, where do most states fall, within a), b), or c)?

MR. KIRBY: I think that most states tend to -- and this was all quoting from the report, so this is the report's -- the way it laid it out. I think commissions understandably lean in the direction of being risk averse, but also a shift we're having is -- and that -- as I say, that -- it's just money. So it's just this question kind of at the bottom where it's saying, okay, we're talking about a buck 63 a MWh and, you know, we don't like customer -- I don't want my electricity bill to go up, but, you know, $1.63 a MWh on a kWh basis, it's not a whole lot of money, so it's a -- you know, that's not an unreasonable insurance premium to throw in.

And so it's understandable if it's just money to, you know -- and, wow, it's $90 million, $270 million, those are big numbers. Ehhh, it's a buck 63 a MWh. Both the same number. So there is a tendency, I think, to lean in the direction -- our lives are simpler, things are easier operationally, even for the Commission, if I don't have to see this volatility, I can make it go away for a relatively low cost. Absolutely true. I don't -- that's your call as a policy call, and I don't disagree with being risk averse.

My point is that as we bring in -- and we haven't seen high penetrations of renewables. You know, this is a new thing to us. So this insurance premium that comes with buying iron in the ground has got other consequences, so it shifts your resource mix, so it's, you know, now it's impacting $CO_2$.

At least with gas you do have the advantage that it's much more flexible than coal, so I can invest in it. I can spend the money. And then if it gets beaten, you know, if the system operators get more experience, they learn more, they're more comfortable with higher penetrations, the solar and wind can push the -- it will always push it off on marginal pricing. So, you know, you can always save fuel later, then all you've done is wasted the capital cost, and that's still a lot of capital cost.

There may be a tendency to I've got the resource, I'll use it. With coal you're in a position where you're forcing. It's got high minimum loads. I can't take the unit offline, so that's really bad. With gas it's more into just the cost.

COMMISSIONER CLODFELTER: Anything else? If not, let me at least follow up on Commissioner Duffley's question. The observation I would make is that at least if we go through the exercise that you've recommended, we know what the cost of the insurance policy is and we can evaluate that against other things we might spend the money on, such as improving reliability at the distribution system level. We can make an informed decision -- the Companies can make an informed decision about alternative expenditures of those dollars because we have actually put a number on them. We know what that aversion, risk aversion, is actually costing us.

MR. KIRBY: Absolutely. The one thing I would add to that is as you look at the cost, also look at saying and this also shifted the resource mix, so I have this --

COMMISSIONER CLODFELTER: I heard you on that.

MR. KIRBY: Yeah.

COMMISSIONER CLODFELTER: Anything else?

COMMISSIONER DUFFLEY: I may have --

COMMISSIONER CLODFELTER: Yes, Commissioner

Duffley. Sure.

COMMISSIONER DUFFLEY: If you'll just indulge me.

MR. KIRBY: Oh, absolutely.

COMMISSIONER DUFFLEY: It's one question about the increase of volatility with respect to demand response. I know within PJM that there were concerns -- you hear this stake in the ground versus a resource that may not show up when called upon, right?

MR. KIRBY: Yes.

COMMISSIONER DUFFLEY: Do you know if there are any -- so here is my indulgent question is, is there any data or any study regarding when demand response is called upon that they did show up or they did not show up?

MR. KIRBY: I'm sure there are, and the place I would look to that would be the Lawrence Berkeley Lab, Ryan Wiser. His group, they publish a lot on that sort of thing. And that question comes up mostly in terms of -- or people raise it mostly in terms of residential, you know. Well, you know, with an awful lot of those technologies -- I have my water heaters and my pool pump are on Florida Power & Light demand response. I have no ability to not respond. It happens. So depending on the technology, that risk ends up being greatly mitigated.

In general, the folks that -- and especially as you shift from -- you look at the economic incentives. So our traditional demand response or our emergency demand response, you get paid and you hope that it's never called upon. And then, you know, then maybe it does get called upon and then we have to worry did the demand response -- you move over into the economic demand response, especially into commercial and industrial, where the demand is being paid for response, that turns the economic incentives completely around for the customer. Now the customer wants to see -- now a customer suddenly likes price volatility, suddenly likes to see what big price I can be paid to respond.

So there's a company in Vancouver that does demand response from -- and the thing I love about it is they extract regulation minute-to-minute response, so it's responding to the utility's automatic generation control signal. The fast -- well, the fastest continuous commands that are being given out. They come out every four seconds, and then moving the generator up and down. And you can find -- you can take -- the thing that Enbala does -- I've worked with Alcoa, and Alcoa has a smelter in Warrick, Indiana, that I talked them into. That smelter runs on MISO’s AGC. So it tracks -- MISO sends it every four seconds a new set point and that smelter moves up. And they get paid for it, so they like it. They’re extremely reliable. They’re watched on MISO’s SCADA system, so it’s absolutely tracked.

Enbala takes that concept down to municipal water treatment sewage and potable water, and instead of getting that response out of each individual sewage treatment plant, they take a whole bunch of them and they construct this second-to-second control signal out of changes in when pumps start and stop across a fleet of water utilities, and they get -- regulation is good because it’s the highest paid ancillary service, so you get -- the customers get from it. And the customers, because of the way pumping loads at sewage treatment plants and water treatment plants and such work, no impact. Enbala makes sure that they have no -- the water treatment guys can never tell that they’re under control. It never impacts their product. It’s just water, you know, because the tank are running between different levels, so they change exactly when the pump starts and exactly when it stops and so --

So the people who -- back to your question of how do you know does it work, the people who have actually used it and in contract for response find that demand response is extremely reliable. It works really well. It's a lot easier to turn things off than it is to turn them on. So for the emergency response, you know, I've got a combustion turbine, that I have it around for non-spinning reserve and, you know, periodically I fire it up. It may or may not start, you know. Demand response, I want something to stop. It's a lot easier to make something stop than it is to make it start.

COMMISSIONER CLODFELTER: Commissioner Hughes.

COMMISSIONER HUGHES: It's just a question about demand response. I mean, what's your, just as an expert looking at this, your predictions about the growth of demand response capacity across the country? I mean, you probably don't know specifics about our service area. Just from following, it would seem like -- the amount of excitement about smart metering and technological improvement has just been second to none over the last 10 years. It would seem like that that would impact the future growth of demand response capacity. Are we seeing that? Are we going to see an exponential growth in demand response capacity or are we going to -- are we doing all of this investment and we're not really going to change the needle?

MR. KIRBY: That is an excellent question. My entire career at the National Lab was -- a good chunk of it was on fast demand response for reliability. And what I argued in all these publications, you can go out on the website, they're all there, read as many of them as you want, so I've argued that demand response is the most underutilized reliability resource we've got, and we have seen it expanding quite a bit. It has not exploded yet, and it's largely because of the institutional obstacles.

Did a nifty study with -- on Long Island with LIPA, Long Island Power Authority, and they had -- it was Carrier's ComfortChoice thermostats and showed -- they were using it for peak reduction, and we did a nice study showing that you could get three times as many MW out of them. They had a lot. They had 80 MW of peak reduction. You can get three times as much response out if you used it for spinning reserve and showed that, you know -- because New York had a market, so there were prices. You could figure out what the value of that was and show that it was much more economical. And so it was a great National Lab study.

And then you go back to LIPA who has -- you know, they were the utility with the relationship with the customer, and they were very good about supplying data and very helpful, very cooperative, but come back to the guy who runs the program and he says that's great; why do I care. I care about peak reduction. Spinning reserves are a reliability issue. That's run out of Albany in New York by the New York system operator. I could care less. So, no, we're going to keep doing peak reduction. Great study. Thanks. Goodbye.

And there was this disconnect between residential customers and system operators. We've always had that disconnect. It's very tough to bridge that. We now have the technology to do an awful lot of really good stuff with demand response, especially seeing electric vehicles coming on. And now we're seeing where we've got the confluence of electric vehicles and solar where -- so I drive my car to work. If I could park at work, it would be really nice to be able to charge it while I was parking at work. That's the exact time that solar is dumping all this excess energy, so suddenly we've got this nice confluence that should be able to work together.

And what I've become convinced, it's not a technical problem. It's so can you get away where it can make the right economic sense to the right person, so here would be an argument, say. So if Duke could come along and if they could find a way to sell charging at public parking lots -- and, you know, electricity is cheap compared to gasoline, so you don't need to be giving the stuff, you know. Even at residential rates it's cheap, so there's lots of opportunity. So if Duke could find a way, especially to say it's a smart car, when the guys plugs in, I don't need to go put a credit card in, I know whose car it is, I've got a relationship with this guy and his residential meter. I'll just go and add it to his electric bill. An incredible opportunity for that to really work and to really help from the systems operations point of view.

And then on top of it helping with the solar excess energy, you know, with your load shape, it also gives you incredible ability to control because that car has got hours to charge and something that will only take it, you know, a fraction of an hour, so a lot of ability to control that. Tremendous technical opportunity. Can we overcome it? Can we get the policy issues, the regulatory issues, the commercial issues? That's the tough part. But the opportunities across the range of demand response are incredible.

COMMISSIONER CLODFELTER: Thank you, Mr. Kirby. Mr. Ledford, anything else?

MR. LEDFORD: No.

COMMISSIONER CLODFELTER: All right. We're going to have to give our court reporter a break, and so I want to do sort of a time check with Public Staff and the Company. I had hoped we'd be able to push through and conclude by a late lunch, as it now appears, but I'm not sure whether we can do that or not. What do you guys think? If we ran till -- I mean, we're going to need to take about a 10-minute break now for the benefit of the court reporter and everyone else. Do you think we could finish by 1:30? That's a very late lunch. Could we do it? I don't want to short you guys because I've --

MR. DODGE: Commissioner Clodfelter, I think from the Public Staff's perspective, we don't anticipate using all of our 30 minutes, so we will -- we can shorten the comments, the brief comments we already had to some extent. A couple of our technical experts do have some afternoon conflicts.

COMMISSIONER CLODFELTER: Okay.

MR. DODGE: Ideally, if we could still be --

COMMISSIONER CLODFELTER: We'll keep going. We won't stop for a lunch break. I'm just suggesting about a five to 10-minute break for the benefit of our reporter. And then if there -- if they don't use up all their time, we'll give it to you guys because you've heard a lot this morning.

MR. SOMERS: Sure.

COMMISSIONER CLODFELTER: Okay.

MR. SOMERS: You know, we're here at the Commission's pleasure.

COMMISSIONER CLODFELTER: All right. Let's take till five after 12:00. We'll come back with the Public Staff.

(Recess taken from 12:00 p.m. to 12:07 p.m.)

COMMISSIONER CLODFELTER: You know, I said 12:05, and it's 12:06, almost 12:07, and we don't have everybody back here, but we're going to do what we said we were going to do. You've got to live by your word, so we're going to start, and people can drift back in if they'll do so quietly. Mr. Dodge, we're with you.

MR. DODGE: Thank you, Commissioner Clodfelter. Before we hand over the microphone to our technical experts here, I just wanted to make a few general comments from the Public Staff's perspective, and we'll reserve most of the time for our technical folks to provide some additional detail.

As you recall, the Public Staff raised a number of issues with the 2016 Resource Adequacy Studies. Some of those have been highlighted, again, today by Mr. Wilson, some similar concerns to some of those he raised.

In the 2016 and 2018 IRPs and pursuant to the Commission's direction in the Sub 147 docket, the Public Staff and Duke did engage in a series of meetings and discussions in late 2017 and early 2018 to work through some of those differences on some of the inputs and assumptions, and a Joint Report was submitted on April 2nd, 2018 to document those discussions.

Duke did respond to a number of the questions raised by the Public Staff. In particular, some of the main ones we focused on were the load response and extreme cold weather events, some of the economic load growth uncertainty issues, market assistance, and some other inputs. I think Duke continued to support the reasonableness of its 17 percent reserve margin at that time, while the Public Staff supported an analysis that -- to look at a 16 percent or slightly lower reserve margin. At the end of the day, the Public Staff and Duke agreed to -- that it was appropriate for the Reserve Margin studies to be updated no later than 2020, and so we hope this discussion today and some of the guidance provided by the Commission can be productive in helping shape that 2020 Resource Adequacy study that feeds into the IRP.

Obviously, the 2020 IRP is shaping up to be very significant, with a number of changes dealing with retirement of generation units, as well as other goals being established through the Clean Energy Plan or Duke Energy Corporation's own sustainability goals. And we appreciate the Commission providing this opportunity to get some clarity on the front end and hopefully provide some expectations as to some of the inputs for the IRP.

Briefly, on the questions the Commission raised in its December 23rd Order regarding the Brattle report or the Brattle-Astrapé report that was prepared for the FERC, we agree that the report provided useful information regarding the various metrics used to evaluate resource adequacy, and we think that it's appropriate to evaluate some of those alternative mechanisms or metrics in the upcoming Resource Adequacy study, such as LOLE or EUE, to ensure that those inputs are understood and some of the tradeoffs associated with a higher or lower reserve margin would be appropriately considered.

We do agree the primary purpose of the IRP continues to be ensuring resource adequacy to keep the lights on, as Mr. Wilson stated, and that the one day in

10-year LOLE metric is still appropriate. However, again, we do support through the Resource Adequacy study looking at some of these other alternatives and then feeding those into the IRP to meet some of these other goals that have been discussed.

The one consideration we think is important to emphasize in all these discussions is that these measures still remain consistent with least-cost planning principles, and that any increase cost that result from any of the changes or adjustments to this would have to be supported by measurable positive benefits to customers.

To get to our technical witnesses, we've requested Bob Hinton, the Director of our Economic Research Division, and Jeff Thomas and Dustin Metz, who are Staff Engineers with our Electric Division, to be available to respond to questions. I believe Bob Hinton is going to start with some responses on load forecasting, and then Jeff will provide some input on additional topics, reserve margin and modeling questions that were raised in the Commission's Appendix A. Thank you.

MR. HINTON: First, I'd start off and say the Public Staff does not have any problem with Duke's forecast for planning purposes. We continue to say the forecast is reasonable for planning. The issues I've raised through the Public Staff Comments have been focused on Duke Energy Progress' winter peak forecast. The summer peak forecast and DEC's forecast are reasonably adequate. I have no concerns with those forecasts.

I've been analyzing the forecast areas for years. As you've seen in IRP comments the Public Staff have filed over the years, the 2018 forecast has Dominion's forecast. The mean square error from 2012 forecast was around 6 percent, DEC's was 5 percent, and DEP was 9 percent. And that's a measure I've used over the years.

The Commission requested tables from 2003 through 2018. We, the Public Staff, only provided '11 through '19, or the IRP forecast from '10 through '18. What these tables show is a concern the Public Staff has addressed with the peaks being under the actual peaks for the wintertime. The wintertime peaks have just been greater than they expected. Obviously, in 2014/'15 we had the polar vortex years, and it's quite understandable those forecasts were below the actuals. But the trend continues, and I've addressed this with the Company.

They have made changes to their model. It will take time to see before -- if those changes are as productive as expected.

But the sources of my concern largely are the model specification, I think they -- I think that may be inadequate, but their end-use data collection they're using now seems not to be able to capture the responsiveness of the customers in the eastern part of the state, largely because we believe there's a higher saturation of heat pumps in that service territory. This stems from years of looking back at gas expansion policies in the state, and it was always the case of the old -- in North Carolina Natural Gas territory, which is now Piedmont East, largely has very low saturation of natural gas. The alternatives are heat pumps and propane. Heat pumps are quite efficient for customers, and so that seems to be the predominant heating source. Census data bears this -- wears this out -- bears this out.

So those are my concerns I've got with -- addresses your Item A and somewhat B. I think it's the heat pump that causes the peaks to rise. As temperatures get not necessarily extreme like in single-digit temperatures, but as it gets closer to 10 degree temperatures, when we get to a normal peaking temperature range, the heat pumps are drawing large amounts of energy, and that's driving the peaks, we believe. So we urge the Companies to continue to work on that issue. We've said that in previous comments and we continue with that today.

The last item was concerning the Blue Horizon project with regarding how the western area has been able to shave the peak and could that be used in the east. We're hoping that AMI data will shed some more light on this as that AMI data becomes available and the discerning of that data becomes possible. The largest area that Asheville, the western area, has is, of course, water heater load control. That's unique largely -- the principle difference between the east and the west. The studies to date the Company has performed have shown that it's not cost effective water heater load control for the winter times, so we struggle to work with that, the Companies are struggling in trying to find a solution to that, and we support their efforts.

So that's largely those items with regard to the load forecast.

MR. THOMAS: Good afternoon, Commission. My name is Jeff Thomas. I'm just going to give a broad overview of some of our responses to Appendix A and working to the December 23rd Order as well.

As you note, most of our -- some of our responses we deferred to Duke, but we did want to just discuss the basis for the 17 percent reserve margin. We continue to stand by some of our critiques of the 2016 Resource Adequacy study which resulted in a 16 percent reserve margin, and what we wanted to emphasize is that it's important for us to -- we feel it's important for us to defend ratepayers' interests by becoming involved with the Resource Adequacy study at the earliest possible time so that we can help to understand the alternatives that are being proposed, the inputs that are being used, the sources of the data, and the modeling techniques.

So we want to emphasize that that early involvement is important, and we hope to be able to do that with this new study because it's not just the three main issues that we identified in 2016, but there are additional issues that will arise, particularly as the modeling has become more advanced.

And also, as we discuss, alternatives to the LOLE standard, such as the EUE and the LOLH, looking at Economic Optimal Reserve Margins, it's important for us to kind of understand the sensitivities that arise there, particularly the Brattle report, you know, looked at transmission enterprise as a big sensitivity, and the Georgia -- the Southern Company Resource Adequacy study also looked at a lot of additional sensitivities like the cost of unserved energy playing a significant component there. So that's really presenting those alternatives and being able to talk about and understand the risk, and then the additional cost is something that we need to be involved on the ground floor.

So moving on to some of the strategic plans to reduce CO2, so question three, just wanted to echo Tim and say that, you know, we want to make sure that the IRP is, you know, making sure that we have reliable and adequate generating resources at the least cost. Any additional policies, State policies from DEQ or from the Legislature, that impose limits on CO2 emissions or other goals that are not related to providing adequate power are going to increase cost as any constraint on a model will do. It was going to increase cost. So we want to make sure that we can understand the cost of these policies as they deviate from a least cost planning perspective.

We saw in Virginia last -- in 2018 the IRP was rejected because it was not quantifying the cost of these policies, and we do feel that's an important aspect, to be able to understand what ratepayers are paying for CO2 reduction under various policies. And we want to make sure that the CO2 reduction plans do holistically consider all aspects of these policies, including stranded assets, system reliability, and accelerated depreciation of assets.

Question four asked about Portfolio 7, which had a high renewable situation, replacing one CT with battery storage. And we looked in this and provided some responses. And it demonstrated that in certain situations and certain cost scenarios adding battery storage, while it increases capital cost, could decrease the total cost of the portfolio over the timeline. We saw that particularly in DEP where the Portfolio 7 was less expensive over the long run than Portfolio 6. So while both scenarios were more expensive than Portfolio 1, or the base case, it did prevent -- demonstrate that batteries do add value and they can be demonstrated even if only one value stream peak shifting is captured.

So we've heard here in Docket E-100, Sub 164, that there are many methodologies emerging to evaluate battery storage in the IRP context because there are values that cannot always be captured by the capacity expansion models. One such approach was the net cost approach, which tends to look at external modeling of battery resources and then use those benefits to reduce capital cost in the Capacity Expansion Model. We heard that in Jeremy Twitchell's presentation. And so that's -- we feel that that's an important component of properly valuing battery storage in the IRP, and we hope that it emerges as an early product of the integrated system operation planning process.

And then finally, question five broadly asked about the benefits of purchased power solicitation and looking at a comprehensive set of potential resources. And, you know, we know that the short-term market purchases in DEP were an effective way to meet load growth without having to build new generation. We, of course, encourage the Company to use the data from not only the short-term market purchase solicitation, but also other competitive solicitations in the state to attempt to defer capital investments when possible and to make sure that Duke is looking at the whole suite of options that's available to it.

And I suppose I -- we could preemptively answer Commissioner Clodfelter's question about what we'd like to see kind of going forward if you were to ask us. And, you know, certainly alternatives to the LOLE metric with significant discussion of cost and risk. We also are interested in understanding how additional -- discrete additional transmission interties that are added to the Resource Adequacy study at a specified and specific cost, how that might affect the reserve margin and the ability to -- the need to actually invest in new generation. That's one aspect that we feel could provide some value.

Rate impacts of the IRP on consumer rates, residential and nonresidential, we feel that's an important component of evaluating the different portfolios to understand how this impacts the ratepayers' wallet. And, obviously, our involvement as early as possible is also important to us.

I think that essentially concludes our comments.

MR. METZ: My name is Dustin Metz. I don't have anything else to add to that.

(Laughter.)

MR. METZ: I'm here for questions.

COMMISSIONER CLODFELTER: I'll open it to questions from the other Commissioners, but Mr. Thomas, a very down-in-the-weeds question about the intertie question. Is your interest in that in interties between the Duke-affiliated utilities or with the surrounding -- where are you interested in that issue? Is it generic or is it confined to some specific locations?

MR. THOMAS: Sure. If you don't mind, I'll let Mr. Metz respond to that.

COMMISSIONER CLODFELTER: Mr. Metz can answer. He can't get off with just saying his name.

MR. METZ: The answer is both.

COMMISSIONER CLODFELTER: So it's generic?

MR. METZ: Right.

COMMISSIONER CLODFELTER: Okay.

MR. METZ: We're looking at potential is there value in doing strategic investments to strengthen the intertie between DEP to DEC to gain synergies or boost in the current JDA and how that can potentially move forward within IRP planning processes.

We're also looking at the possibilities of how are our interties with our neighbors is turning to, I think, the entry into the Brattle Report of little "v," is this the most significant factor impacting our regions? Planning reserve margin is the size of the transmission interties.

COMMISSIONER CLODFELTER: The reason I ask the question was I believe the 2016 Resource Adequacy study looked at a case in which the Duke affiliates were treated as a single balancing area and operated that way, and it didn't appear to me to be -- to change very much the -- sort of the reserve margin outcome -- output, and that's why I was sort of interested in whether that's what you're exploring or you're exploring something else.

MR. METZ: Well, one of it is looking at where to invest money in certain parts into the grid. The second part of --

COMMISSIONER CLODFELTER: Okay.

MR. METZ: -- to that point is it may not change the reserve margin, but did we defer a unit which has a value to ratepayers? And essentially that's what that model came out, is we were able to shift, hypothetically, this combined cycle one year to here. Well, that has systemic effect. Well, now I can move two CTs to here. And it just -- it did have an effect of continued deferred new generation, and as you deal with uncertainties with load as new technologies emerge, it's beneficial.

MR. HINTON: And may I add, this is timely now because currently DEC has some excess generation. DEP will be coming up short in 2025 for their next projected need. So the concept of deferring that one year may provide some valuable benefits to ratepayers.

COMMISSIONER CLODFELTER: Thank you for that explanation. That's great. Questions from Commissioners?

(No response.)

UNKNOWN SPEAKER: He got off easy today.

COMMISSIONER CLODFELTER: Almost with just your name, Mr. Metz.

MR. METZ: All most.

COMMISSIONER CLODFELTER: All right. Mr. Dodge, anything else?

MR. DODGE: Thank you, Commissioner Clodfelter. I would just note I believe Mr. Metz has a 1:00 call, so if he -- if there were follow-ups for him to be called back, just wanted to -- he's available until that time.

COMMISSIONER CLODFELTER: All right. That's fine. Just a wild guess prediction is you probably won't be called back, but we're glad to know you're here till 1:00.

MR. METZ: All right.

COMMISSIONER CLODFELTER: Mr. Somers, I am not going to push you, because the other parties have had a lot of time here. I'm going to ask you this question, though, is do you think you can get us done by a late lunch or do you think we'd probably need a lunch break? The reason I ask that question is I've been told by a couple of my colleagues that they've got some questions for you.

MR. SOMERS: I'm hungry myself, but I absolutely believe we'll be done in time for a late lunch.

COMMISSIONER CLODFELTER: All right. Let's push on, then.

MR. SOMERS: All right.

COMMISSIONER CLODFELTER: It's with you.

MR. SOMERS: Thank you. If I could, I'd call forward Mr. Brunson, Mr. Snider, Mr. Wintermantel, and Mr. Kalemba. And as they're coming forward, if I could just give some preliminary comments --

COMMISSIONER CLODFELTER: Yes.

MR. SOMERS: -- to be efficient with the time. We have not prepared any presentation. I think that will -- we --

COMMISSIONER CLODFELTER That's fine.

MR. SOMERS: -- believe that the better use of our time will be responding to Commission questions. We believe that certainly the IRP Reply Comments and then the -- hopefully the information we filed on November 4th was responsive. I understand from the Order right before Christmas there may be some additional questions based on that, and so we thought it we would save a formal presentation rehashing what we've told the Commission a couple of times over the last four years, and instead be prepared for questions.

I would like to ask a couple questions to let the Panel respond to some things we've heard from some of the other commenters.

COMMISSIONER CLODFELTER: I was going to -- I was going to suggest that, is that if you've heard anything this morning that you're burning to respond to before you get to Commission questions, let's do that now.

MR. SOMERS: Okay. And in addition to the folks who are up here, we have other members of the Companies' IRP and load forecasting teams who would also be available.

COMMISSIONER CLODFELTER: Great.

MR. SOMERS: So if I could, let me just begin by introducing our Panel members, beginning first with Mr. Brunson, and this is his first opportunity to appear before the Commission. Would you please introduce yourself, state your name and your position?

MR. BRUNSON: Yes. Hello. My name is Leon Brunson. I'm the Senior Load Forecaster for the Carolinas, both DEC and DEP.

MR. SOMERS: Mr. Snider.

MR. SNIDER: I'm Glen Snider. Good to see you again, Commissioners. Thank you for the opportunity to appear before you today. My name is Glen Snider. I run our Integrated Resource Planning and Analytics for both DEC and DEP.

MR. SOMERS: The other reason, if I may say with somewhat tongue in cheek and with a great deal of professional respect, the reason we didn't prepare slides is with a 30-minute limit, Mr. Snider would have taken our full 30 minutes with one slide.

(Laughter.)

MR. SOMERS: Having said that, Mr. Wintermantel, please -- the record will reflect I got a lot of laughter, including from Mr. Snider.

MR. WINTERMANTEL: Yeah. Sure.

MR. SOMERS: Mr. Wintermantel, would you please introduce yourself?

MR. WINTERMANTEL: Sure. Happy to be here, Commissioners. My name is Nick Wintermantel. I'm a Principal at Astrapé Consulting. I've been here, I think, one other time. I would just -- a little background of Astrapé, we're a resource planning type consulting firm, with a real focus on resource adequacy. Our SERVM model which has been used by Duke Energy, we performed studies throughout the U.S., large RTOs, SPP, MISO archive, so the model is well vetted from that standpoint. It's been used in the industry pretty extensively for Resource Adequacy, Reserve Margin studies, Renewable Integration, and those types of -- those types of studies.

MR. SOMERS: And sometime later you will be able to get into that FERC report and how the Duke process compares to other utilities in the United States; is that correct?

MR. WINTERMANTEL: Yeah. Sure. I can definitely answer questions regarding the FERC report.

MR. SOMERS: Okay. Mr. Kalemba, would you introduce yourself?

MR. KALEMBA: Sure. Matthew Kalemba. I'm in the Integrated Resource Planning team for the Carolinas, Principal Planning Analyst, reporting to Mr. Snider.

MR. SOMERS: Mr. Davis?

MR. DAVIS: I'm Tom Davis. I work in the Carolinas Integrated Resource Planning group for Mr.

Snider, and I've had some -- or involvement with the 2016 Resource Adequacy study and working with Astrapé.

MR. SOMERS: And last, but not least, Mr. Stillman.

MR. STILLMAN: No. Thank you. And thank you for having us here. I'm Phil Stillman. I'm the Director of the Load Forecasting group, so I work very closely with Leon and oversee the development of the forecast in all of our jurisdictions, including Duke Energy Carolinas and Progress.

MR. SOMERS: So if I may, I want to try to put some of what we've heard from some of the other commenters in perspective, and if I could, I'd like to start with you, Mr. Snider. And instead of coming at this from the perspective of a lab research or a theoretical economist perspective, I want to talk to the person whose job is on the line if Duke has not adequately planned its system to serve its customers' needs. Is that person you?

MR. SNIDER: That would be.

MR. SOMERS: Okay. So we heard some criticisms earlier in the morning about how Duke has its thumbs on the scale, I believe was the quote from Mr. Wilson, when it's establishing its reserve margins that this

Commission approves, and that there are a lot of things that go into determining whether the Company has adequate reserves to meet its customer needs, including looking at what your utility neighbors might have available, what our DSM programs are and what the weather might have been when it was cold apparently only in 1980. And I would like for you to put this into a real-world context, if we could, in recalling many of us were in this room, called in by the Commission within the last five years when we had some extreme winter cold and Duke Energy was very close to not meeting its customers' load needs. If you could, please put into perspective the weather and load events over the last five years, how that fits in with a reserve margin, and how Duke works with its alleged thumb on the scale to present a reserve margin in the IRP process for this Commission's consideration.

MR. SNIDER: Certainly. So maybe to respond to Mr. Somers, there is a lot of technical detail that's been presented to you today. I mean, we're talking some pretty heady stuff with LOLH and EUE and LOLE and bathtub curves and economic optimal, and it's -- there's a -- as you've heard today, a lot of academia and a lot of studies that are going on, and good studies, and we're making progress on those.

But sometimes it’s good to sit back and just say let’s take a look at what’s actually transpired and what’s driving some of these reasons for these analytics. And, you know, I can think of three times in the last five years where the Southeast and Duke, in particular, has had razor-thin reserve margins during the winter and were very, very close to organized load shed during those events. You had a polar vortex of 2014, a polar vortex of 2015, and I think we got tired of using the word polar vortex, so we just said the first week of 2018 was really, really cold. And in each of those cases, as was pointed out earlier about the load portion, we’ve come out of the recession, we’ve built some new generation, load didn’t grow, so it’s important to let’s start with what is a reserve margin?

First of all, a reserve margin is just a target in planning that means how much extra generation do I have relative to load. So you take a look at how much generation do I have available to me at time of peak, what’s my projected -- and this is an important one -- weather normal load peak demand, my weather normal peak. Not my extreme peak, but my weather normal peak. And that gives you an excess amount of generation, because I've got more generation than I have peak demand. And then I divide that by peak demand and I say, okay, that percentage is a reserve margin.

And I carry that reserve margin for three fundamental reasons. I carry a reserve margin to handle extreme weather. So when we look at weather normal demand, we say over a 30-year or a 35-year period what is the average peak. But I might not have an average peak. I might have an extreme peak, so I've got to have resources for that.

The second main reason for a reserve margin is physical assets are not 100 percent reliable. So when you have forced outages of CTs or CCs or, you know, a nuclear plant, you have to be able to serve that peak demand knowing that when you have 150 plus units on the system, not 100 percent of them will be running, so you’ve got to cover a forced outage, right?

And then the third piece, and while it’s a smaller piece, it still is a piece of it, is you’re projecting your weather normal peak demand three, four, five years into the future, and the economy can peak up and go beyond where you expected, and so you can have load forecast error. And so if I’ve under-forecasted load, which is what Mr. Hinton’s concern is with DEP is our under-forecasting of load, you still have to have generation even though you've under-forecasted load.

So you have this sort of long-term load forecast error, unit outages, and then you also have, you know, importantly, these deviations from an average weather condition. And so when we look at that, we said, okay, we went into 2014, '15, '18, we weren't at the 17 percent minimum planning reserves. Your reserves will be lumpy through time. As load forecast change, you build a new resource, you've got excess. The target reserve margin is just when do I build that next generator. I don't want to drop below it. And I understand that over time I'll have years where I'm above it, and as I approach it again, we put a new resource in place, make sure we don't drop below it. So it's a little lumpy over time.

So we went into '14 and '15 in the 25 to 30 percent winter reserve margins. And, again, this was sort of pre-moving to winter planning, so we were maintaining summer reserves, but as a result of that, and we weren't deep into the solar yet, we hadn't built for winter demand, we were planning summer, when you look at what our winter reserve margins were, they were 25 to 30 percent. And in both of those events the Company nearly did not serve load. And, in fact, in 2014 we had what's called negative operating reserves. So we came in then, I think Nelson Peeler came in in a Monday morning agenda conference and spoke to this body about the fact that we ran out of our own resources and were actually relying on non-firm purchases from our neighbors to serve load.

And what I just, you know, remind the Commission is that wasn't at 17 percent or 15 or 16 or 12 and, you know, there's big debate on what's that economic optimal bathtub curve. That was something well to the right of that, and we were relying on neighbors that if those neighbors would have cut that sale, our next option was rotating feeders.

And that very thing happened in -- I believe it was '15; it may have been '14, so where SCANA was relying on non-firm, we had to recall it. We needed it for our own. And SCANA actually had to have rotating feeders. And, you know, that was -- you know, when it is rare, you know, I guess, Commissioner Clodfelter, I would say that, you know, all outages sort of aren't created equal because when you run out of generation during an extreme weather event, the impact on customers and the customer response is very, very different than if you have a hurricane and a bunch of trees fall on power lines. You get asymmetric responses.

I came into the industry in the ‘80s in Illinois Department of Energy and went down to Florida in the early ‘90s. That was right after Florida Power in ’89 had a load shed event Christmas Eve because they had unexpected 20-something degrees in Tampa, and they turned off power on Christmas Eve. It’s hard to believe there’s anybody still in Florida alive to talk about it, but to this day people talk about the Christmas Eve outage of 1989, and you go to conferences and people will talk about that or they’ll talk about in the ‘90s when we used a lot of DSM and we were relying too much on DSM, and half the customers got off the DSM program because you had to hit it too many times.

So what happened in those events is you really had asymmetric responses to these events. No one was talking about the hurricanes back then, but they still talk about the utility running out of resources during critically cold periods.

And so, you know, I guess my point would be is, you know, at the end of the day this is a big discussion around risk, reward, and the cost, and we’ll get into a lot of that today with your questions, and Mr. Wintermantel and Mr. Brunson and the rest of our team are happy to dive into those details. But in practice, you know, I think there -- you know, maybe two points I'd want to make is there is a much different response when you're out of power and it's 10 degrees than if you're out of power and it's 70 degrees out.

When it comes to things like DSM, you know, one of the things we're seeing, you know, it's hard to pinpoint exactly what appliance at every single customer, but if you just think about it logically, for example, you can load control like we did in Florida air conditioners, and when you turn off air conditioners, there's little that the customer can do. When you turn off heaters, if you get too cold in your house, you turn your oven on, you turn your space heaters on, you go to Lowe's and you buy more space heaters and you just plug them in. And, you know, there are -- people do not want to fundamentally be cold. I'm not saying there's not room for DSM. I certainly am not advocating that at all. There's certainly promise in additional DSM. But it has its limits in terms of how long you can turn them off.

If you start clipping that peak -- another thing I'd like to, you know, make clear, what we've seen in Florida, what we've seen in the Carolinas is you're not actually clipping a peak; you're moving that energy in time. So you're preheating or you're postheating.

The heater is going to make up for that heat it didn't heat or it's going to preheat it. And air conditioner is going to run harder after you turn it off. So you're actually shifting the energy use in time and flattening that peak, which just makes a lower peak, but the next peak you've created is longer. And so you get a change in your load profile. It's not simply eliminating that peak demand.

So, you know, one of the things we see in the industry a lot is this big desire for load control, which is a good thing, but it has its limits in terms of as you start to flatten that and broaden it, now your two- and four-hour batteries have less value because I've just made my peak six hours and eight hours because I've moved it with DSM.

So you've got to look at this all holistically. I think there's no silver bullet in this. I do encourage, you know, questions, and we're certainly willing to work with parties on articulating the risks and rewards. But I will just say that history has shown, you know, there is an ability in the last five years and, again, three times I can point to, where had we been at 17 percent, we would not have served load. And so even at 17 percent, you know, there is still risk, and we can

-- you don't want to have too much. It's too expensive. As we've talked about too little, you get a lot of volatility, and that can be very expensive. So where is that right middle point range? I think that's where, you know, working with parties, you know, working through our updated Resource Adequacy study we're -- you know, we're looking forward to presenting those risk, reward tradeoffs as we move into our 2020 IRP.

MR. SOMERS: Maybe just a couple more. I know you all don't want to hear me ask questions. You've got better questions than I do. But maybe if I go to Mr. Wintermantel. There was a lot of discussion in earlier presentations about one in 10 LOLE and, you know, I'm a lawyer and I maybe understand what that is. I know that's what you do for a living. But could you put into perspective for us what that means as a standard? Who relies on it? Is Duke or North Carolina overly conservative by using that as the basis for developing a reserve margin? I think it would also be important if you could explain, at least for me, how does that LOLE calculation, is that in and of itself the reserve margin or how does that factor into the development of a reasonable reserve margin?

MR. WINTERMANTEL: Yeah, yeah. Sure, I can certainly talk to that, Mr. Somers.

So we did hear a lot about this topic this morning, and as far as defining LOLE, LOLH, and EUE, I think we agree, you know, LOLE is just a count of events. There is this standard, and the one day in 10-year standard says I'm willing to shed load one event every 10 years, and that is the overwhelmingly industry standard. And I think the FERC report -- I know the Commission has brought up that FERC report. There's a survey. I encourage you to go look at the backend. I don't know the number, but I'm going to guess more than 70 percent of the entities base their Resource Adequacy on one day in 10.

Now, the modeling can certainly -- let me just back up. So in the modeling all we're doing is we're modeling the system and we're increasing reserves, so we're looking at a 10 percent, 11 percent, 12 percent, up to 20 percent reserve margin. And for Duke specifically, and I know we haven't talked much about this, but this shift to winter has -- it's a focus, when I say 10 to 20 percent, I'm really talking about winter reserve margin. Our studies have kind of validated that if we have a 17 percent winter reserve margin, we're going to already have a 15 percent summer. That's mainly due to the solar.

As we increase solar -- I know I'm getting off topic here, but as we increase solar, the summer reserve margin is going to increase more than the winter reserve margin because of the capacity value of that solar.

But backing up to the modeling mechanics, we're just -- we're modeling 10 percent reserve margin. At 10 percent reserve margin, the model spits out LOLE, Loss of Load Expectation, LOLH, and EUE. And as Mr. Wilson, I think, pointed out, your typical event is in the two- to five-hour range, so a .1 -- stay with me here -- one day in 10 years typically equates to .3 hours per year. And so I think the FERC report does a good job in saying if you use a 2.4 hour per year standard, you're much less stringent, you're much more risky than a one day in 10, because one day in 10 is typically going to be about a .3 LOLH. 2.4 LOLH is certainly much higher, and you're actually expecting to shed load every year if you use a 2.4 LOLH.

And then EUE is simply just the magnitude of the Expected Unserved Energy. It's a good metric. In fact, in the 2016 studies it was an output of the model. We just didn't focus on it because we're on the one day in 10-year standard. So I think while it gives you additional information, I believe the one day in 10-year standard used by other entities, used by Duke, has served the industry well.

And I think one thing I really want the Commission to take away either from the FERC study or the 2016 Astrapé study, is what we find when we look at the economics of slightly less than one day in 10 or slightly above one day in 10, we really see that bathtub curve. It’s flat for several percentage points. It’s very, very flat. So the impact on customer cost of moving from, say, a 15 to a 17 percent, what we see in all our studies, what we saw in the FERC study is relatively small, and with that small increase in cost, you’re reducing your volatility substantially, so it’s worth your insurance payment, as Mr. Kirby brought up. I thought Mr. Kirby did a good job explaining that reserve margin is definitely you’re making an insurance payment. You’re paying for additional capacity to offset some of this risk.

I would also make the point that when we add a MW of CT capacity, as we do in our study, there's certainly a cost to that, but every MW we add there is some benefit, and so that’s what keeps that curve somewhat flat, right, because we are reducing the cost of making expensive purchases, the cost of EUE, and those are the main two items in our modeling. But as you go too far, 20 percent, 25 percent, which the Company is certainly not there today, that value diminishes.

But it needs to be clear that just because we go from 15 to 16, our cost is not the cost of the CT. We do get benefit of that CT and that needs to be recognized, and that's why that curve is fairly flat, so there can be a pretty good sweet spot, I think, for the Commission to determine, look at risk and cost and compare that to the one day in 10-year standard. But to me, the cost impact is not that significant.

MR. SNIDER: Within that -- sort of in that range.

MR. WINTERMANTEL: Yeah. Within the -- in that range.

MR. SNIDER: And, you know, just one last clarity point on that. When you add that new CT, it's at today's technology, so these CTs are more efficient, lower fuel use, lower carbon output than some of the rest of your fleet. So you've got 20, 30 year old units that are less efficient, maybe burning oil or burning gas at more expensive cost, so you're actually maybe running these inefficient units less for a small number of hours out of the year and running this more efficient. So that's just another -- you know, when you're at reasonable levels of reserve margin, another benefit that offsets that capital cost of it until you start to invest in too many of them, and then that's why the curve goes up, is then you just have inefficient deployment of capital. So there's just those factors that help create that bottom portion of the bathtub curve.

MR. WINTERMANTEL: And one minor point, just, you know, I know the FERC study is the example study. I don't want to take you too far, because that study is based on some summer peaking utility, and so the risk that's described in there, I would argue, would actually be even a little bit higher for a winter peaking because the volatility around load in winter, if you are constrained to winter peaking and that's your planning metric, there's higher volatility in what that winter load can do compared to summer. So it's a nuance, but I just want to make it clear that I think the FERC study was a summer peaking, so to try to take numbers and even take the reserve margin levels, I think we need to be careful there. That's not a winter peaking study.

MR. SOMERS: Before I move to load forecasting and Mr. Brunson, was there anything else you wanted to respond to that you heard in presentations earlier today based on the reserve margin topics?

MR. SNIDER: I guess, you know, maybe just a little bit of response to, you know, we did work with the Public Staff extensively after the ’16 filing many of the issues, the sensitivities, the data validation, the models. We put hundreds and hundreds of hours after the report was filed, after our IRP was filed. We went to several in-person meetings, several phone calls with Public Staff, and so a lot of the things that were sort of represented as, you know, didn’t get addressed, they were fully addressed and then some. I mean, we put significant effort.

You know, Public Staff and the Company at the end of all that came down to a 1 percent difference. There were a few nuance details that I’m not going to articulate here where Public Staff supported 16 percent, the Company felt 17 percent was a better representation. We show a 16 percent analysis in the IRP and base the IRP on 17. But, you know, I guess my, you know, the one -- the one thing I would bring to the Commission’s attention is there -- you know, a lot of things that were claimed not to have been done were actually -- were not only done, but they were done to an excruciating level of detail.

MR. WINTERMANTEL: And to that point I would just add from a kind of thumbs on the scale perspective here, I think there were a couple items that we went back with Staff to kind of go through, I think some -- the load forecast error, the weather extrapolation. We performed some sensitivities to kind of show the impact, so I think the impact of those was a little bit overstated if we look at the study holistically.

So maybe just an example, we used three-year ahead load forecast error, and the reason is because we expect it takes at least three to five years to build new capacity, so we're making this decision for 2022 today. We're kind of on the hook for meeting that load, and we kind of need to make the decision three years in advance. So that's why load forecast error is three years in our model, and that's what we assumed. If we change that to one-year forecast error, we drop the reserve margin by 1 percent.

When we look at other inputs into the model such as system EFOR, if you look at the historical data that we looked at, it was a -- it was a good operating period, you know. I think the system EFOR was in the 3 to 4 percent range if you look in the appendix of the study.

MR. SNIDER: EFOR is forced outage rate.

MR. WINTERMANTEL: Sorry. Forced outage rate. So when you think about system forced outage rate in the model, our generators are performing pretty well. So that would actually -- if that increases, it would actually make this go back up.

The other one is market assistance, which I think Public Staff hit on significantly. It is a significant assumption. And I do want to add some color to market assistance, because as in the 2016 study, we looked at removing it all, and to get to one day in 10, that reserve margin jumps about 6 percent, so I want us to be careful that we're already assuming that we're lowering our reserve margin by 6 percent. We're taking into account these ties.

When a cold weather or a hot weather event occurs, it's typically for surrounding areas as well. If you look at the '14 event, PJM was certainly going through issues. TVA and Southern were certainly going through issues. So to say we can always rely on the market, I think we just need to be careful there. We're taking it into account. We're going to look at it again this year. We try to calibrate the historical. We spent significant time looking at pay and peak periods, what did we get from the market in the past. We try to make sure the model is consistent with that. But that is a big assumption. If we miss that, then certainly one day in 10 -- one day in 10 is off.

So at least from a market -- the other piece is market assistance is typically more for capacity shortage than transmission shortage, is what we see at least in the Duke studies. Adding more transmission, the transmission is probably there, but the real issue is they're getting the same conditions in the capacities, just not on the other side, so --

So if we were to change that assumption to be a little bit more aggressive, then reserve margins would need to go up, right, if we assumed less market assistance. That's probably a bigger driver than maybe these 1 percent critiques that we're getting on load forecast error, so I want to put it in perspective.

You think about how PJM does their reserve margin study. They certainly have significant physical capability, but they actually put a hard limit on what they're going to expect from outside neighbors. They assume 3,500 MW transmission line, which is about a 2 percent import capability of their peak load, so they're already a little bit probably more conservative on that side.

There are lots of assumptions. They all need to be addressed, but I do believe in 2016 we spent extensive time validating those, and so those critiques I do take issue with.

MR. SOMERS: If I could move to load forecast. Mr. Brunson, that's your responsibility, along with Mr. Stillman and Mr. Davis, but the concern expressed by the Public Staff was that the DEP winter forecast has been too low. You've been under-forecasting the peak load. And some or the other criticism from some of the other commenters today has been that Duke doesn't seem to know why the DEP customers are having such a response to extreme low temperatures in the winter. Could you just take a minute or two to address with the Commission what you and your team are doing to make any adjustments to the load forecasting methodology or what's been done in response to past Commission orders to ensure that the Company presents the most accurate load forecast, again, understanding that no one can predict the future?

MR. BRUNSON: Sure. And it's correct, and I can start --

MR. SOMERS: I'm not sure that microphone is working very well. Maybe pull it a little closer.

MR. BRUNSON: Okay. It's better? And I can start where the Public Staff left off, Bob Hinton, and his assessment of the DEP winter peak was that one of the primary drivers was the lack of natural gas, particularly in the DEP eastern region, as well as the overabundance of electric heat pumps. And that's one of the primary drivers of why you see these real sharp spikes on very cold winter days in DEP versus DEC.

But it goes a little further than that. There are some real distinct differences between DEC and DEP from an economic standpoint, and we summarized a lot of this information in the responses that we provided in November, I believe. There's economic implications from household incomes, and if you think about the argument of how -- over the past years in North Carolina how parts of the state's -- metropolitan areas of the state are growing much faster than non-metro areas, that kind of plays into our industry as well. Household incomes are lower in our smaller cities and rural areas. They are lower. The housing shells are little -- you have more mobile homes.

Since the recession we've gone from home ownership to increasing renters that, you know -- which is, you know, you're increasing the number of electric heat pumps. All of these factors and a few more that's outlined in our summary combined leads to, you know, those spikes that we're seeing in DEP.

So what are we doing to address it? Well, the first thing we did, going back to the 2016 Commission Order, we went and took a very hard look at our forecast process and made some changes. And we believe those changes have produced some very positive effects that you'll see in the upcoming -- in the 2019 IRP and in our upcoming 2020 IRP.

Some of the other things we do is we are constantly reviewing and updating our inputs from economic inputs, which we get from Moody's Analytics which is our economic vendor. We're in constant contact with our vendor. We look at and analyze their economic projections. If something looks a little odd to us or what -- you know, in terms of what we think the outlook would be, we are on the phone with them and asking them to explain it. So we're not taking these projections from, you know, and just blindly utilizing them in our models. We ask a lot of questions.

You know, what we also do is we're lucky that we have six jurisdictions help forecasters, and we often get together and we talk best practices, what's working, what's not, how do you approach this problem, how do you overcome, you know, any issues that you're having in your jurisdiction.

And so those are some of the few things that we are doing to address, you know, to help keep the forecast -- to increase the forecast accuracy not only in DEP, but in DEC as well. It's a continuous process with us.

MR. SOMERS: I have to ask, Mr. Wilson characterized Duke's explanation of customers' response to these extreme winter temperature events as blaming low-income and rural customers. Are you in any way blaming customers for how they respond to extreme cold weather events in your work?

MR. BRUNSON: Oh, absolutely not. The data that -- the analysis that is -- that came from these tables and charts that we provided came from research from the EIA, and our data that we use in our models come from the EIA that generate our -- that gives our projections to our end-use models. So we have a lot of confidence in that data as well as their analysis. They are -- and it's an industry standard to use the data and analysis.

So when we say -- when you hear -- and I'll take an example that we're blaming rural households for spikes in, you know, cold temperatures; that's not what the Company is saying at all. What the Company is saying is that the EIA analysis points out that it is more likely that households that are in rural areas may have -- because of housing structure, maybe because of lower incomes, maybe because of, you know, other -- lack of availability to natural gas and an overabundance of heat pumps, you know, on average, those group of households will -- you know, will have a higher intensity of heat than, say, a household in Charlotte that has gas heating. Household income is probably higher and has a more efficient outshow.

MR. SOMERS: Thank you. Commissioner Clodfelter, I could ask 10 more questions, but I'd rather the Commission ask the questions that it believes are important, and so I'll --

COMMISSIONER CLODFELTER: It's your choice, your time.

MR. SOMERS: I would be happy to defer at this point and hand it over to the Commission.

COMMISSIONER CLODFELTER: That's fine. Yeah. Sure. Start off, Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Mr. Brunson, just a follow-up on your last point regarding residential and rural use in the wintertime. I think one of the things Mr. Wilson pointed out, though, was there was no discussion about the commercial impact of extreme weather. Do we have anything, you know, to answer back regarding commercial?

MR. BRUNSON: Sure. And he was correct to point that out. But the question that was posed to us was what is the primary driver of winter, you know, winter -- spikes in winter peaks. The primary driver is residential and it is space heating. Commercial does have an impact, but a lot less impact. That's why we focused on residential.

COMMISSIONER BROWN-BLAND: Are there -- you know, just for our knowledge and education, are there specific drivers or impact that come along with commercial use?

MR. BRUNSON: There are. I don't have them with me, but we can supply that. If my memory is correct, it was in the report, so we can supply that.

COMMISSIONER CLODFELTER: Gentlemen, I want to start you off with a question that's not really technical; it's more quasi policy. And then I've got others, but I want to start you with this one to get some context, and then I'll let others ask their questions after that.

The IRP -- I want to talk really about the role of resource adequacy in the IRP process, so it's a bigger picture contextual question. And let me illustrate the question or give it some reality by taking the 2019 update. I pulled that only because it's the -- it was easier for me to get my hands on it. It was higher in the pile than the 2018 report, so it came off the top.

So the objectives the Companies articulated in the 2019 IRP report, there are three objectives for the planning process. One of those is a physical objective. That's the resource adequacy or reliability metric. The second one is a economic objective, and that is to determine the lowest reasonable cost portfolio of resources. The third -- and let me say for those who think we are still at too early a stage to talk about the Clean Energy Plan, this is the Company's objective. The Company's articulated objective is to reduce carbon emissions by 50 percent relative to 2005 baseline by 2030. So that's an environmental policy objective, but the Company has articulated all three of those objectives.

So really what I want to understand is how resource adequacy fits into that context. And so the question, really, is does the Company take the position and believe that it's possible to solve for all three of those, to optimize all three of those values? Are there cases that the IRP needs to examine where there are tradeoffs being made among those three different objectives, one physical, one economic, and one I'll call it environmental policy, or does the Company think you can solve for all three and optimize all three in a single solution?

MR. SNIDER: So I'll take that one.

COMMISSIONER CLODFELTER: I figured you would.

MR. SNIDER: Certainly, I think, you know, I think it was Mr. Thomas pointed out whenever you add a constraint to the model, you're going to increase cost, right? So to go from 50 to 55 to 60, pick a number north of a carbon constraint, that's going to have a cost implication. But we should have a discussion in the IRP around our sensitivities to what are those cost tradeoffs to change that trajectory of carbon reduction. So if we want to go to ever higher levels, what's the cost benefit discussion? And through sensitivity and scenario analysis, we can have that discussion.

When it comes to reliability, I don't think that's a tradeoff that we're currently envisioning right now. In other words, the fundamental starting point, and we can agree to disagree or say we still have to decide is it 13, 14, 15, 17 -- TVA is using 25 right now for winter peak demand -- what is the optimal point to let reserves go to before it's time to not let them go any further? You shouldn't -- and our current estimation is you shouldn't trade that to say you know what, I'll just accept more risk, I'll be more risky and I'll not -- I'll take the chance I'm not going to serve load when it's really cold out or really hot out more often to achieve another objective.

And so I think you start with what does a reliable system look like, and I think the industry has, though, you know, by and large uses the one day in 10 standard. We can have a pretty robust discussion of if I go up or down in that, what's the real economic implication of that and what are the pros and cons. And so I'm not saying you just present one. You can talk about what are the pros and cons in your reliability assessment of moving to different levels, and we're fully supportive of that, but I would not view it as, hey, we're going to get to lower carbon or we can save a few dollars if we'll just, you know, every year be willing, you know, three days a year just not serve load or something to that effect. So that's not a tradeoff we're currently envisioning in the IRP.

So you correctly state there are those three pillars, and I think you can make a tradeoff in two of the three pillars, but you need to snap a line in the sand and say what does a reliable electric system look like, and then no matter how you pursue planning, how do you maintain that level of reliability that's expected from your customer base?

COMMISSIONER CLODFELTER: That is a very clear and, actually, for you, a very succinct answer.

(Laughter.)

COMMISSIONER CLODFELTER: I really appreciate it. That was a model answer.

MR. SNIDER: My boss is in the audience, so I'm checking that off on my, you know, professional goals.

COMMISSIONER CLODFELTER: Well, I hope your boss heard that. It's a model answer. I mean, it's a very, very clear answer, and I thank you for it. And I want to ask you this follow-up. Let's assume that is the position that the Company takes, let's assume that's the consensus position that's agreed to. I don't know whether it is or not, by the way, but let's assume it is and that everyone agrees that that's really the line you snap in the sand. Would it not be useful, though, to at least know the cost of that policy choice, and doesn't that really sort of go to really what we've been talking about with some of the other presenters this morning, is what is the cost of the insurance policy I'm actually buying and how do I get a sense of that so that I can say oh, yeah, I'm willing to pay that --

MR. SNIDER: Absolutely.

COMMISSIONER CLODFELTER: -- to get that outcome on physical reliability? I'm willing to pay that. And for that purpose don't I need to know in my IRP what's the alternative baseline? For example, the baseline might be the risk neutral economically optimal reserve margin, and I could say, okay, that's a, yeah, an academic measurement point, but we're going to go with something different than that and this is the choice we make and this is what it cost us to make that choice. That cost is dollars that we don't put on something else. Isn't that a useful exercise to do?

MR. SNIDER: I believe it is, Commissioner Clodfelter. I think in our updated comprehensive resource adequacy assessment we will show both the physical reliability of carrying less insurance --

COMMISSIONER CLODFELTER: Right.

MR. SNIDER: -- lower reserve margin, what does that physically mean in terms of expected outages, and what's the cost difference from these various levels of reserve margins so that we know that as we move -- use any of these metrics to move in terms of how much insurance we want to carry, what's the net cost to consumers for carrying that level, I think is a very reasonable question to expect to be answered out of a Resource Adequacy study.

COMMISSIONER CLODFELTER: Well, thank you. Again, thank you for that and I want to stay with it because, again, I think that's why we're doing this exercise here is, in part, because some of the reasons you're getting some of the comments you're getting and some of the reactions you're getting is that that's baked in in a way that it's not really apparent to others who haven't been in the process, haven't been in the room with the Public Staff, haven't been working with Mr. Wintermantel on the details of running the models and the scenarios and don't really know, and so it's not really open and obvious for all to see. What could we do as a Commission -- I'm going to jump to the question I've asked earlier, but on this specific point is there anything useful this Commission could do to help you in making the IRP a more useful document on the point you just made, on the point you just raised? Is there anything we could do to assist you in transforming the document itself and the plan itself into a more useful illustration of the choice that's been made?

MR. SNIDER: I think it's fair for this Commission, when it has an expectation of what will be presented in the Resource Adequacy study, the types of scenarios it would like to see, the number -- I mean, at some point we're trying to balance, you know, the doability and the actual logistics, cost, time, you know, we all have limited on both of those, with, you know, where is the bang for the buck in this Resource Adequacy study, so what particular range of sensitivities you might want to see, ensure that we meet those expectations up front and not after the fact. It is fully our intent to engage Public Staff early on in this process and get their input into it.

And so, you know, I think anything you do that provides some guidance in that is beneficial, and we'll endeavor to do our, you know, our very best to meet those requirements.

COMMISSIONER CLODFELTER: Thank you, again. I hope you appreciate that part of this exercise here is to try to do something in that direction. We have to first get educated before we can say anything useful at all, and right now we may not feel that we're educated, but, again, in the past all you've been able to do is you roll it out and then everybody shoots at it, and I think what we're trying to explore here is, is there a different way of doing business.

So I'm going to stop with that at this point. We may come back to it later. I've got some other topics, but we're running out on time, so I'm going to let others ask questions as well because I know some people have some questions. Commissioner Hughes.

COMMISSIONER HUGHES: Thank you all very much. I've always found that communicating risk, we can talk about it one way that people understand it. If I could just get a clarification for my own education on how the model works. And I apologize. I'm new to this job.

But is it safe to say that when we've been talking about this one in 10, if I was communicating it to a neighbor or my mother, I would say, Mom, expect -- expect, not it might, but expect that you or someone you know around town will lose power in the next 10 years? Is that a better way to say it, or should I tell her this year you or someone you know around town, 10 percent likely to have -- how would you communicate it? Does that make sense, that difference?

MR. SNIDER: Right. Yeah. I think the one thing I would add is a lot of discussion leading up to this, that when it -- you can lose power many more times than that for other reasons. A tree can fall, right?

COMMISSIONER HUGHES: Oh, absolutely. Yeah.

MR. SNIDER: So if you start with, you know, there is about a one in 10 chance that this year, if we have a really cold winter, you know, you may not have power for a certain number of hours, and I think that is -- or, you know, that's the level of reliability when it comes to building enough generation. We can't say under every single circumstance we'll be there. Like I said, I think if we were at 17 percent in 2014 and '15, this would be a very different discussion because we'd be having this discussion on the other side of one of those events. But we're -- you know, we're not planning for 100 percent, so I -- you know, Commissioner Hughes, I agree with how you -- I think either way is correct. You can say, you know, only once a decade should you expect the Utility not to have enough generation built to meet extreme weather or it's 10 percent chance that this next year could be the year, because we don't know -- you know, that's the one thing we can't do is forecast weather well into the future. I mean, we get a week or 10 days, that's one thing. But I remember most of these polar vortex events, people were scrambling six, seven days in advance. Three weeks before that there was no discussion of it. So you don't know when you're going to have that cold-weather year, you know, other than the Farmer's Almanac. You know, you just can't say, you know, when am I going to have that really cold, but, you know, the Utility plans that, you know, nine years out of 10 you will not have --

And, you know, we had a discussion on the way over. What's interesting in this is that doesn't mean once every 10 years. It might be three times in a decade and then not for three decades, but the way to communicate it to the layman is, you know, only one year in 10 is the planning process set up to have to shed load as opposed to being able to have enough generation to serve you.

COMMISSIONER HUGHES: Well, thank you. I do think that explaining it either way is problematic because I think customers react very differently to thinking about 10 percent of something happening, because then they like to think that it will never happen because they're a lucky person and it will never happen, whereas it's a real very different thing when you say you know what, it's going to happen to you in the next 10 years, we just don't know when it is. And --

MR. SNIDER: That's a fair point.

COMMISSIONER HUGHES: Yeah. So I think, you know, and I think the Commission has to understand that, you know, can we be angry with you if the thing happens in Florida when you told us it was going to happen once in 10 years? Well, it happened, right? But if you just tell us next year, you know, 10 percent chance, we're going to kind of give the idea that we're playing with odds and that you somehow made a mistake, you know, and you blew it because, you know, you had -- you know, you had 90 percent chance of getting it right. So I just -- I'm trying to understand this for what I'm paying for, because I think if we can expect it to happen for this reason, you know, one in 10 years, I just need to be comfortable with that.

And the follow-up question for that is if you can expect that to happen one in 10 years, so the Florida situation, not if, but likely will happen in our service area, what's Duke's current operating procedure or policy for dealing with that? Is it a two-hour rolling blackout? Is it a five-hour? And what is -- what's the current operating procedure for that?

MR. SNIDER: So without getting too much into the real technical details, what happens is you're going to maintain a little bit of generation for grid stability, so you're actually going to turn customers off before you exhaust every bit of your generation. And then what you're going to do is you're going to continue to rotate feeders until load drops or, you know, in the winter case it may be solar starts to come on at 8:00, 9:00, 10:00 in the morning, so a resource you didn't have you now have, and so I can stop rotating feeders, right? So it's very situational dependent. And the very last thing you want to do is rotate feeders, so we will do everything in our power, from neighbor assistance to using all of -- and that's another, you know, thing that came up earlier. In the model we assume we use all of our operating reserves except for that very narrow sliver to maintain grid stability, so we will use the operating reserves. We'll buy from our neighbors even if it's really expensive. We'll put out public pleas for conservation, which sometimes don't fall on pleasant ears. You know, we were receiving responses back in the polar vortex event.

You know, you would think everyone would say we get it, it's never hardly this cold, it's a good thing to conserve, and some people are that way, but that's not everybody. We get a lot of responses back saying this is exactly what I'm paying my power bill for. I don't want to feel cold and put on a sweater and a coat in my house because it's 10 degrees out. I want my house toasty. And it's a different -- we can agree or disagree with that perspective, but the Company sees that perspective coming in.

So, you know, longwinded answer, I apologize, but it is really, you know, situational dependent. It's our very last option. We'll do everything in our power to avoid rotating feeders, and hopefully it is short. I will say, though, you know, as you clip more and more peaks, and what we've seen is, yeah, that 6:00 and 7:00 in the morning are the highest hours, but we've had entire days where you've only had a couple thousand MW drop from your peak, you know, a few thousand MW to your min. load for that day. So as you start bringing that peak down and, you know, batteries then raise my off peak, you know, DSM moves it to other peaks, so those peaks get wider and longer. And then the risk discussion changes because that feeder, then, by definition might have to be longer in a different portfolio world. In a world with a bunch of batteries and a bunch of DSM, now my LOLE gets spread out amongst more and more hours, and that's a little bit more technical, but -- so, again, very situational, very portfolio dependent.

COMMISSIONER HUGHES: Well, last question is just to put it so I can understand the perspective, when it does occur, relatively how does that occur? I mean, we can't look at hurricanes where we've lost power or when I had a two-week old baby and I lost power for 12 weeks -- I mean, excuse me -- 12 days for the ice storm, we don't know when that is all going to happen in storms, but for this other one we're modeling it, I'm just trying to understand the relativity of that.

Right now I'm assuming that Duke has disconnected customers for nonpayment, right? I mean, that's -- I mean, every utility out there has a certain number of disconnects. Not something we enjoy, but also something the Commission is really concerned with. What kind of percentages now are disconnected today versus what would happen when this rolling blackout happens? Do you have any idea? I mean, is it orders of magnitude? Is it -- I know that's sort of -- it's an out-of-leftfield question.

MR. SNIDER: Well, maybe one thing --

COMMISSIONER HUGHES: If you need to get back to me on it, that's fine.

MR. SNIDER: -- on that is even in that, which is an interesting point, and I'll let Mr. Somers, if he has more information on this, but even the disconnects get suspended during these really cold weather events, is my understanding. And Mr. Somers, correct me if I'm wrong. Not my area. But as I understand it, we will not disconnect somebody when it's 12 degrees out. And it just goes back to, you know, Commissioner Clodfelter, where an outage is not an outage, right, an outage at 10 degrees.

So, you know, at any given point I don't know if anyone here on the Panel has an idea for what percent we have off due to nonpayment or credit issues, but I know -- you know, when I think about that in a cold weather event, we don't like to see that during extreme weather.

MR. SOMERS: If I could just add. I can supplement you with the detailed answer, but as Mr. Snider said, we have a moratorium during winter period and in high summer periods where we do not disconnect customers for nonpayment. I don't know the number that are disconnected for nonpayment today at this moment and the exact parameters of when we don't. We have that moratorium due to weather, but I will be happy to get that for you.

COMMISSIONER HUGHES: Yeah. I'd be -- and, I mean, I understand the difference of cold weather, but also there's a lot of discussion about we want people to have power at their house, so there's periods of time where a lot of people don't have power to their house because of nonpayment, and there's periods of time that people aren't going to have power to their house for emergencies. I'd just like to get them all in perspective.

MR. SOMERS: We will supplement with that.

COMMISSIONER HUGHES: Thank you, sir.

COMMISSIONER CLODFELTER: Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: So Mr. Snider, you mentioned in response to Commissioner Clodfelter a minute ago that in the upcoming reports you will net out and show the cost of our decisions where we can see. Will that include what you mentioned earlier, take into account the benefit of having a newer technology and the benefits?

MR. SNIDER: Yes. That’s a good question. And, yes, it will. So what we’ll do is we’ll say, you know, here’s the amount of capital you have to spend, and it’s more and more to get more CTs online. But as Mr. Wintermantel pointed out, what we’ll show, then, is especially at reasonable levels there’s production cost savings from putting these online.

Now, if you have a bunch of deployed capital that never gets dispatched, then it’s sort of really expensive insurance, but we’ll show the net benefit, so here’s the cost, and then here’s the production cost savings, the purchase cost savings. And because the value of unserved energy is such a small number, it is, though, a portion of it, but we’ll show it, and that will make clear to the point of how much of that benefit of unserved energy and how important is it that we get it right. Is it 5,000? Is it 10? Is it 3?

You know, you can look to recent events and see where, you know, the one example I was going to bring up is ERCOT, that the one -- that’s the only one I know that doesn’t have a reserve margin. They just let the market -- and it went to over $10,000, the market clearing price, when the wind stopped blowing this past summer.

But it doesn't drive the study, but we'll show it and that will be good, so there will be transparency on that, how much is driven by value of unserved energy, how much purchases, and how much just production cost benefit. So we will net that all out.

COMMISSIONER BROWN-BLAND: And then I have kind of a nontechnical question just to have insight into the Company's work in this area. Do you have any idea kind of the Duke work hour time that is spent on resource planning and resource adequacy, or you can tell me the best way to quantify that time, but is this a year-round effort --

MR. SNIDER: You know, I would say leading into this update --

COMMISSIONER BROWN-BLAND: -- that the Company works on all the time?

MR. SNIDER: -- and, again, that's a good question. You know, it's a four- to five-month effort at least. And, again, to Commissioner Clodfelter's question, that can vary depending on how complex we make the study, how many scenarios are run, how many people are involved, you know, so it can grow pretty exponentially. But our current plan is about a four- to five-month study using internal resources, as well as, obviously, Astrapé who is our retained consultant on this. And so we've both -- got both internal and external. It is not any one person's full-time job, but Mr. Davis, it's a big chunk of his job for the next four or five months, and then other people on my staff will be heavily involved. So I guess what I'm saying is maybe, you know, collectively, if I had to put a quick number on it, you know, 1 point something FTEs for five, six -- a couple FTEs, maybe, when you look at collective time from all the people that'll be reviewing it for five or six months leading into this, with potential room to grow if this scope --

COMMISSIONER BROWN-BLAND: Percentage of their full-time --

MR. SNIDER: Yeah.

COMMISSIONER BROWN-BLAND: -- job?

MR. SNIDER: Yeah. And if I add -- my five or six people all are doing little bits and pieces, and I sort of add them up into maybe a couple of FTEs. And we'll have senior management reviewing it. We'll have -- you know, there's a fair amount of eyes that will fall on this throughout the process, but I think about it as, you know, about that many months and, you know, a few people working on it and then Astrapé's engagement.

COMMISSIONER BROWN-BLAND: And I would assume that this is something the Company would work on, whether or not there was regulatory requirements around it or not. I mean, you just have to be able to plan. Can you in any way quantify how much time is dedicated to the regulatory piece of it?

MR. SNIDER: Yeah. That's a good question. I mean, you know, we would do this, you're right. I mean, we need to have adequate power supplies with or without in order to, say, do a study. But, you know -- and I can turn it over and maybe put Nick on the spot here a little bit. I know internally they're doing the study, but then there's -- I think we answered hundreds of data requests. We've had written testimony. You know, obviously, we come in and present to Public Staff throughout the process and we come in and have this adjudicated case. So there's probably, you know, an extra 25, 30 percent just sort of administrative piece of it, and that's a pure sort of eye in the sky on my part of -- you know, we have to write testimony and we've got to answer interrogatories, we've got to have a hearing on it, so that adds to the administrative side of it, but that's part of the process, so it's not a criticism of it. It's just part of the process.

COMMISSIONER BROWN-BLAND: Right. Those -- you're using the term extra, but is that included in your first number to me or are you saying this is layered on top of it?

MR. SNIDER: No. I think that's extra.

COMMISSIONER BROWN-BLAND: Okay. Thank you.

COMMISSIONER CLODFELTER: Before I ask for others, I want to follow-up on one of Commissioner Brown-Bland's questions to close out the question and then get questions from some others. Probably from Mr. Wintermantel and Mr. Snider both, it goes to something that sort of has puzzled me in the 2016 Resource Adequacy study and in the November comments. And it really focuses on the total system energy cost analysis. And there was a statement in the November comments that the total system energy cost analysis showed that it was more costly under that metric to use -- to carry a 13 percent reserve margin than an 18 percent reserve margin, and I thought to myself, well, how could that be, and I thought, well, it's obviously because of the value of unserved energy. Expected unserved energy is the explanation for that delta. I went into the resource report to look at that, and the difference in the value of expected unserved energy does not account for that, cannot fully account for the difference. So my question, really, is I'm wondering is that because -- Mr. Snider, is that because the addition of the additional resources from 13 to 16 percent -- to 18 percent, they're going to be dispatched in a different order, they're going to change the order of economic dispatch, they're going to change fuel O&M cost? Is that why we're seeing that result? Is that why we're seeing that result?

MR. SNIDER: I'll let Mr. Wintermantel add to it, but it's that, plus, you know, again, we do rely, as you pointed out, on market assistance, and as you know during, you know, high extreme events, market assistance doesn't come cheap because everybody is in the boat.

COMMISSIONER CLODFELTER: Okay.

MR. SNIDER: And so you're avoiding both expensive market purchases. But even throughout the year you've got these new efficient turbines that are displacing less efficient turbines.

COMMISSIONER CLODFELTER: Right.

MR. SNIDER: You may be displacing oil turbines with gas. Since you can get significant -- it's not a lot of hours, but it can be significant dollars because there's a big MWh difference at times.

MR. WINTERMANTEL: Yeah. I think that covers most of it. It's scarcity pricing situations, but in the model it goes both ways. If Southern is experiencing it, then Duke sells into that and gets the benefit of having a CT as well, so it's on both sides of the coin. But, yeah, there's just basically value to that CT beyond the firm load shed event. And, you know, the energy cost distribution at each reserve margin level you can see how volatile, so what happens on that far right side of the curve, in the really high extreme cases you're -- those are the -- obviously, the significantly severe weather years you missed your load forecast error, all these events taking place, and those costs stack up significantly.

COMMISSIONER CLODFELTER: Thank you. Questions? Commissioner McKissick.

COMMISSIONER McKISSICK.: Thank you, Commissioner Clodfelter. And it's really a follow-up on some of the questions that Commissioner Hughes was asking, because I have a similar steep curve of learning as a part of this Commission. But I'm just curious, in your modeling, when you look at this year and day in 10 years, I mean, what are you assuming would be the potential period of interruption of services? I mean, is there a range of time that a customer might potentially be without service? I mean, what does that actually look like and translate into?

MR. SNIDER: Take a shot at that.

MR. WINTERMANTEL: Yeah, yeah. Sure. So in the model, so it’s probabilistic, right, so we’re looking at out of all the simulations and iterations. So we’re running a full year -- I think for this study it was 2020, but -- so we’re looking at 2020, and we’re rolling the dice and running thousands of 2020s; one with high load, one with different generator outage profiles, based on all historical data of what could happen in 2020. So if we’re running thousands of iterations, we’re figuring out the probability that we’ll have one event in 10, so we’re basically taking all of these thousands of iterations and abbreviating it down to this ratio of one in 10. But that really does mean that we’re going to have one event in 10 years.

An event is typically a few hours across a day, three or four hours across a day, so that’s kind of the ratio we’re getting to, but we do have to realize we’re rolling with lots and lots of iterations to get to that probability of one in 10. But, yeah, the layman’s way would be to say basically one event in 10 years, which is equivalent to about a three- to five-hour type event.

COMMISSIONER McKISSICK: Typically, about a three- to five-hour event within that range would be what a customer might experience in terms of interruption and you would -- I guess it sounds as if based upon the modeling, you would say that you'd go out and it would be rotated in your service area. Who would be without service during that period?

MR. WINTERMANTEL: So it would be a subset of customers, and I would let Mr. Snider -- I don't know -- I mean, I don't know the priority of how you guys disconnect. I'm sure it's some equitable disconnecting of customers, but it is a subset, so obviously not everyone is losing power.

COMMISSIONER McKISSICK: Right.

MR. SNIDER: So, you know, and I'm -- again, this is in past discussions with system operators, and to get the actual protocol and procedure we could follow up with that, but it's my understanding that we have certain loads that are designated critical, so I think nursing homes, hospitals that have critical load designation, they are exempt from the feeder rotation. And so that -- sometimes they're not isolated, so -- you know, I remember one time I think I was fortunate to live on the circuit of a nursing home, and so I was always restored quickly and it was always accused that it was because I worked for the Company, and I said, no, I don't know those people, but, you know, it was fortunate that I was on that feeder. But other than that, it's just an equitable distribution of noncritical load, and so there isn't, you know, any priority other than that, you know, who's deemed, you know, sort of life critical, and then everybody else gets rotated.

Now, how that exactly works and, you know, how many minutes each one goes before it comes back to them, that's not my area that I --

COMMISSIONER McKISSICK: Sure.

MR. SNIDER: -- traditionally work in.

COMMISSIONER McKISSICK: And let me switch gears a little bit, and this is going back to the, I guess, the difference between the Public Staff, their position on the 16 percent reserve versus 17 percent reserve. Can you tell me from your perspective why 17 percent is a more valid number to use in projections?

MR. SNIDER: Yeah. And, you know, to be fair, Public Staff took an issue-by-issue approach and did a very, you know, comprehensive deep dive into each of those issues. And I think, you know, our primary area of disagreement is, you know, when all the Intervenors come in and say -- you know, which is typical in these proceedings, not just the Carolinas, but as you hear Nick talk or others, you know, there's a body of Intervenors that would like to see the Utility carry lower reserves and build less generation. So they come in with all sorts of criticisms to say issue by issue, and there's dozens, as you've just heard, dozens of inputs that go in, here's an issue I have, but they're limited to any issue that can lower it.

There's very little Intervenors that say, hey, you're not carrying enough reserves. I'm concerned that you're being too aggressive on cold weather outages. I'm concerned that you're being too aggressive and relying too heavily on your neighbors. These proceedings never adjudicate themselves that way. And so what we said as we came to the end of it is you raised some, you know, reasonable points for consideration on specific finite issues that may tend to move you from 17 to 16. We tried to point out but there are -- and while there's reasonable debate on those issues and we respect their opinion on it, there's also reasonable debate that we were pretty, as Mr. Wintermantel pointed out, pretty aggressive to only go to 17 percent. We relied heavily on the neighbors. We assume that outages at the units are totally random and there's not a positive correlation to cold weather means more outages. Pumps freeze. You know, things happen when it's 8 degrees out that don't happen during normal outages. So if you would have had a positive correlation of outages with cold weather, we would have had to carry higher reserves.

We didn't put that correlation in, so we just argued that, hey, we don't necessarily disagree with Public Staff that there is some concern on a couple issues, but on balance, if we were to take a holistic view and say, yes, well, there's a reasonable debate on each of these individual inputs, the process sort of works itself out where you only debate one side of the equation. The Company feels appropriate that you should debate where you've been not only conservative, but also where you've been aggressive, and that on balance we were still reasonably low, as a matter of fact, aggressively low, in our opinion, to stay at 17 percent, especially when looking at history.

So we just agreed to disagree at the end of that 1 percent difference and say, you know, not that we disagree with you on each specific issue, but we thought that on balance, 17 percent was still more appropriate and in the best interest of customers, while we respect

Public Staff's position on discrete finite issues, so --

COMMISSIONER McKISSICK: And --

MR. SNIDER: -- that's sort of what led to it.

COMMISSIONER McKISSICK: Sure. And last question. Also keyed into that same issue, I mean, from what I could read, it looks like historically when you were doing your projections, that your projections had always been on the higher side in the past than what was needed from -- if you would review the actual demand and need. Is that an accurate interpretation, or did I perhaps misread what I saw in the file and, I guess, read these materials in the last 24 hours?

MR. SNIDER: Yes. And, you know, my first thought when this was your first day on the bench was, oh, my Lord, what an issue to jump right into. It's like let's give the new Commissioner LOLE, LOLH, and EUE --

COMMISSIONER McKISSICK: Yeah.

MR. SNIDER: -- and see if he's here tomorrow. But -- no. I appreciate --

COMMISSIONER McKISSICK: I will be.

MR. SNIDER: I appreciate that, you know -- you know, how foreign this must sound on day one. But as Mr. Hinton pointed out from Public Staff, I think from a load forecast perspective what his concern is, is actually just the opposite, which is --

COMMISSIONER McKISSICK: Okay.

MR. SNIDER: -- on a weather-normal basis, we consistently, for lots of reasons that Mr. Brunson discussed and others, is we've actually consistently been projecting here, and then weather normal has been higher. And so, you know, to some extent we're doing a lot of research and saying, you know, are we actually getting that DEP, you know, the issue of heat pumps and substitute heat sources and, you know, are we getting that right? Why are we under-forecasting? At DEP, the eastern Utility, we have of wholesale load relative. We didn't talk about that today, but that wholesale load, historically we used to treat -- we'd get an energy forecast and we'd say it must look like the rest of the system, and we'd just apportion it into each hour of the year. And then, you know, after digging deeply, the load forecasting group said, you know, we need to improve that process. Wholesale customers are munis or co-ops. They're much more rural, much more residential, and so while, yes, they have a certain amount of energy, the hours in which and how they're going to consume it is not the same as the rest of the retail system. So they're improving how they forecast our wholesale load as part of this improvement to try and understand these differences.

But Commissioner McKissick, what we're seeing, though, is actually the opposite, which is we've been under-forecasting. We're trying to understand why and create that so that our forecasts are more in line.

COMMISSIONER McKISSICK: Yeah. I remember now reading about the polar vortex on two occasions. Thank you for your input.

MR. SNIDER: You're welcome, sir.

COMMISSIONER CLODFELTER: Gentlemen, I want to come back to a planning question. Again, it's not so much a technical question as it is a planning question. And I want to take off on one of the items in the November responses. The Companies sort of indicated that if you're looking in the near term, there's greater certainty on load forecasts and maybe even on -- certainly, you know more about planned outages, you may know more about delays in bringing new capacity online, you're better able to determine scheduling of new capacity additions and so forth and that, therefore, you might be able to sort of get by with lower reserve margins than over the longer 15-year planning period. Well, the Commission Rule requires you to do a 15-year plan, a 15-year forecast, but the observation in the

November filing suggested to me a question, and that is whether it would be useful to run adequacy sort of targets on a five-year, a 10-year, and a 15-year basis to see what we're managing. And this is why I ask that, is we're in a time of enormous flux and change in the evolution of technologies and business models, evolution of regulatory models, and so forth, and everyone is telling us, you guys are telling us -- you guys are ringing the bells just as loudly as anyone else -- that the world is going to look very differently maybe five years from now or 10 years from now. We don't have to wait 15 years for the world to look very differently. And so that leads to the question of should we be looking at what are our risks -- what's our risk that we're carrying over a shorter term because we may have bridge options or we may want to talk about bridge solutions or we may want to talk about bridging strategies that get us through a shorter term period before we make long-term commitments and long-term investments. To do that, though, we need to know what risks are we undertaking on shorter time frames. Would it be useful to have a reserve margin that's based on a five-year forecast or 10-year forecast instead of just 15 years? It's a planning question.

MR. SNIDER: Yeah. I'll answer this, and then if Mr. Wintermantel has -- because he's probably seen this in many other parts of the country. I'm going to do it from a Duke-centric perspective.

I think you bring up a very good point with respect to load forecast uncertainty, right? So we have a much better idea -- if you remember, the reason we picked three or four years out when we say how much load forecast is, that's how long it takes to build a generating unit, and so if I get this economic recovery, well, you know, it's unlikely that's all going to happen in six months. So I think it's fair to say that in the near term, one, two, three years out, you could carry -- you don't need to carry as much for economic uncertainty because you have a better vision on that.

With that said, if we took -- you know, of the entire reserve margin, if we remove that one variable, that's why I made it my third point -- remember, there were three points, weather, unit outages, and economic uncertainty. That economic uncertainty is, you know, if I remember right, Nick, was like 1 percent, right? So if we removed economic uncertainty altogether or had one year out -- was it --

MR. WINTERMANTEL: I think one year -- if you have a one-year load forecast error it moves it 1 percent, but I do think if you remove it all, my memory says it’s worth about a percent and a half of your reserve margin. So if you completely know what our economic growth assumptions are -- you still have weather uncertainty, right, that’s in every year -- but that’s really what you’re looking at.

And then, really, beyond four years you can make -- like Mr. Snider just said, you can make that decision again, so you really don’t need to look at uncertainty beyond that three- to five-year period because you always have that decision going forward.

COMMISSIONER CLODFELTER: Right.

MR. WINTERMANTEL: But inside of four or three years, there’s a little bit of room, but you've got to think previously you’ve already planned for that three year based on a reserve margin, so all of a sudden it drops because you missed the load forecast, you might still be okay because you’ve got pretty good certainty around what that load -- even though your forecast says it’s actually gone up, went the wrong way, you’ve got some uncertainty because you’re in that window.

MR. SNIDER: So to summarize, I think a short-term and a long-term I don’t see necessarily the value of having like a five, a 10, and a 15 --

COMMISSIONER CLODFELTER: Okay.

MR. SNIDER: -- for that, but to say --

COMMISSIONER CLODFELTER: Right.

MR. SNIDER: -- hey, could we live with a little less in ’20 and ’21 or ‘22 compared to beyond. So what’s my 15-year planning horizon? Maybe 12 or 13 of those years I ought to have my long-range, you know, whatever number we settle on after we have the whole RA report, but it’s fair to assert -- and analogous to that, I remember back when we had really high inflation. I think we used to -- this was pre my time -- rather than have a single inflation rate, we said, you know, that’s just not sustainable long run, and we had a long- and a short-term inflation rate in the model that said, you know, we know it’s high, but we have a lot of econometric data, economists saying that’s not sustainable for a 15-year window, so we had two different inflation rates in our IRP models. I think it’s reasonable to say you have a short-term reserve margin that you could potentially have slightly less because you’re not exposed to that economic uncertainty to the extent you are in the long run, and so, you know, I think there is some merit in considering that.

COMMISSIONER CLODFELTER: And if we did that, that might sort of affect how we evaluate the short-term action plan. That's really where it would show on the ground --

MR. SNIDER: Right.

COMMISSIONER CLODFELTER: -- is the way we approach and the Company approaches the analysis of what's the short-term action plan.

MR. SNIDER: Right. I think that's fair.

COMMISSIONER CLODFELTER: Okay. Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Mr. Snider, has the Company thought about or planned on engaging with the co-ops and munis in a different way or a different manner than the past in order to improve your view of the load?

MR. SNIDER: Yeah. You know, we have ongoing meetings with the munis and the co-ops, and the issue I just spoke about is one of the things we've been raising with them. You know, we're -- it's a two-way street, right? They want to know a lot of our forecasts and projections around building and cost and, you know, they're a big part of that puzzle, so we want to know their load growth, so we're -- we actually are engaging with them, you know, throughout the year, and as these contemporaneous issues arise, we're putting them in front of them and trying to get their input, you know, with their expertise with their individual member co-ops as well.

So one of the things, you know -- and I'll let Leon, if he wants to add anything to that, say, is, you know, we are taking, you know, their load forecast and we're having a much more robust discussion with them than maybe we did in the past, or we're looking at how we apply that to our total shape a little differently than let's say we were five years ago.

So, yeah, there definitely is, you know, a symbiotic relationship with the munis and the co-ops, where we're all facing these same issues together, and so we're trying to make sure we're on the same page from planning, including load forecast.

COMMISSIONER BROWN-BLAND: Yes. I was going to ask Mr. Brunson -- I mean, so you're seeing improvement over time in how -- in the forecast as it's affected by the munis and the co-ops?

MR. BRUNSON: Yes. So one example that Mr. Snider mentioned earlier was how we came to the realization of that their shape was a lot different than we thought previously. There were more residential, which means they were a little more spikier during, you know, the winter peak season. So, you know, Mr. Snider mentioned that earlier.

Another good example is maybe about eight months ago we had a meeting with one of the wholesale contractors, and it was a collaborative effort on -- with electric vehicles, how to implement that part of the load, best practices, expectations going forward with the vendor that we -- that was also a part of the conversation. Everybody expects that to be a very big change in our load going forward, so that's a good example.

COMMISSIONER CLODFELTER: All right. Anything else from Commissioners?

(No response.)

COMMISSIONER CLODFELTER: We've worn you out maybe long enough. We've worn out the court reporter, I'm sure of that. Mr. Somers, anything else?

MR. SOMERS: I don't think so. Thank you very much.

COMMISSIONER CLODFELTER: Thank you all. I really want to express our deep appreciation to everybody for engaging in the exercise this morning. It helps us when we learn more and get a chance to explore things when we're not in the heat of battle, as it were. So I really appreciate that. Mr. Metz returned. Yeah. Do we need to call him back, just to get him back up to say his name again?

(Laughter.)

COMMISISONER CLODFELTER: All right. With that, we are concluded. Thank you all.

(The proceedings were adjourned.)

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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 157, 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 20th day of January, 2020.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150