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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:

Technical Conference

2020 Biennial Integrated Resource Plan Reports and Related 2020 REPS Compliance Plans by Duke Energy Carolinas and Duke Energy Progress

Volume 2

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P R O C E E D I N G S

COMMISSIONER CLODFELTER: When we broke, we had completed the presentations and we were ready to deal with questions, so we'll start first with any questions from Commission Staff. Mr. McDowell? Mr. McDowell is taking a late lunch. I know he has questions. Let's go ahead and see --

MR. McDOWELL: I am back and I do have just a couple of questions.

COMMISSIONER CLODFELTER: Okay.

MR. McDOWELL: This is for the team in total, I'm not sure which individual specifically, but on this slide 10 it was mentioned that PacifiCorp subsequently rejected endogenous retirement. What's the -- what's the subject matter there?

MR. FISHER: I'm sorry. When you say "What's the subject matter" --

MR. McDOWELL: Yeah. Well, just --

MR. FISHER: -- in terms of what they reject?

MR. McDOWELL: -- that decision. Do you have any insights into that?

MR. FISHER: Yeah. So PacifiCorp didn't necessarily explain its reasoning in full, but subsequent to this IRP it started looking a little bit more closely

at its Regional Haze obligations, and at least it made the case that the complications of looking at its Regional Haze obligations and the potential to -- at least within the West -- trade off between units with different Regional Haze obligations made it too difficult to look at an endogenous retirement scenario and, rather, look at more explicit tradeoffs between plants that could allow for environmental compliance.

MR. McDOWELL: So that would have been with tools such as System Optimizer?

MR. FISHER: That's right. It continued to use System Optimizer and it continued to look at unit retirements. It just took into account a series of additional considerations that have tradeoffs that were more difficult to implement within the modeling structure.

MR. McDOWELL: Okay. Thank you for that. So PacifiCorp apparently uses PLEXOS now; is that correct?

MR. FISHER: I believe so.

MR. McDOWELL: And PLEXOS and EnCompass have similar capabilities or functionality?

MR. FISHER: I'm going to turn to Rachel to discuss this if she's a part --

MS. WILSON: Sure. They're --

MR. FISHER: -- on this one.
MS. WILSON: They're generally similar capabilities, though the two use different algorithms, and so you wouldn't necessarily expect that you might get exactly the same results if you were to put the same inputs into the two models.
MR. McDOWELL: Okay. But they work in this -- in a similar direction or --
MS. WILSON: That's correct. Yes. They have many of the same capabilities.
MR. McDOWELL: So on your last slide, your recommendation for Duke is to revise the coal assessment methodology and update the coal retirement study. I think I read that correctly.
MS. WILSON: That's right.
MR. McDOWELL: And in an earlier slide -- and I don't know whether to connect these or not; I wrote this -- as you stated on an earlier slide, increasingly sophisticated energy system models can endogenously evaluate and optimize unit retirements and cost effective replacement. So was -- is that what the recommendation is, for Duke to move to a model that -- to model the coal retirements endogenously in what you are proposing, or is it --

MS. WILSON: I think our recommendation is a combination of approaches, and --

MR. McDOWELL: Okay.

MS. WILSON: -- this is -- modeling unit retirements is as much an art as it is a science, and so oftentimes it involves doing a model run, going back and making a change, doing another model run, and comparing, you know, the results of all of those runs.

So I think that our recommendation would be to use endogenous retirements where you can. When you can, make sure that you're taking into account the limitations to endogenous retirements, and then also performing a unit-by-unit analysis where it could be informative or when you're dealing with specific constraints like Mr. Fisher mentioned that don't lend themselves well to endogenous retirements exclusively.

MR. McDOWELL: Okay. Thank you for that. I appreciate that clarification. Are you familiar with PacifiCorp's 2021 IRP and the report that was published earlier this month?

MR. FISHER: So this is Jeremy. To be honest, I actually have not been following as closely for this year's PacifiCorp process, and I believe that AG consultants may be speaking to that process.

MR. McDOWELL: I glanced through the report and read on page 221 that -- and I'll quote here -- "New to this IRP is using the long-term model to consider the retirement of coal endogenously." So that's a quote from their IRP report that was just released in early September.

What is discussed as new to the PacifiCorp IRP sounds very similar to part of the recommendation that you would have Duke take or others might suggest, other parties might suggest. Is that your take on that? Again, I can read this statement from the IRP. "New to this IRP is using the long-term model to consider the retirement of coal endogenously," which is a -- sounds like an evolution from what they were doing earlier and the position they had taken.

MR. FISHER: Yeah. And I apologize. I don't mean to get us down into the weeds for how PacifiCorp's IRP process has evolved over the years. It has --

MR. McDOWELL: Please don't.

MR. FISHER: I won't. It has evolved substantially, and Sierra Club and other Intervenors have had substantial concerns with many of the ways that those analyses have either been conducted or ultimately determined at the end of the day. So I believe that

coming off of the last resource planning process there was a concern amongst Intervenors and Staff from selected states that PacifiCorp should probably return to an endogenous mechanism or include an endogenous mechanism in the way that it's looking at its coal retirement assessment. I don't think that the statement that it is completely new to their system is actually accurate. It was --

MR. McDOWELL: Okay.

MR. FISHER: -- in 2013.

MR. McDOWELL: All right. I appreciate that. I may ask Mr. Burgess about that same statement. He may be more familiar.

Thank you. That's my final question.

MS. WILSON: So I'll also just add that their use of a new model might have influenced that decision as well. System Optimizer has specific limitations in the way that it does its optimization, and so that might also constrain somewhat its ability to do endogenous retirements. The shift to PLEXOS might have enabled PacifiCorp to -- and this is speculation on my part -- might have enabled PacifiCorp to, you know, revitalize that methodology for its IRP going forward.

MR. McDOWELL: Okay. Thank you very much.

COMMISSIONER CLODFELTER: I think we'll turn to Commissioners. Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Thank you. I don't have any questions.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: Thank you as well. I have no questions.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: I do have a few. And you all just bear with me here because remember I'm a lawyer, so the technical stuff is difficult for me, so just forgive kind of questions that may be -- that may sound just stupid.

But help me understand -- I mean, I've listened to you all's presentation today, followed along as you've described your recommendations. And I think I get them for the most part and the limitations that you all have described with respect to the tools that Duke used and the way that Duke employed its analysis, but at the end of the day, what is going to be -- let's assume for a minute that Duke took -- followed your recommendations and performed its analysis as you would have liked them to. Where does that lead? What's the outcome?

MS. WILSON: So I'll start. I think it leads

to, first off, an assessment of, or a conclusion, rather, of which econo--- which units, rather, are providing value to the system and which are not at this point. And in addition to that, looking forward, if there are units that are providing value today, is there a date at which Duke anticipates those units are no longer going to be valuable, and if yes, what is that date.

They would provide backup to their analysis. We would be able to see workpapers that, you know, demonstrate their methodology, that we could follow through to see those calculations and see the evidence that that analysis was done. So that would be Step 1 is, you know, redoing this rank ordering of unit retirement dates to truly be economic.

And then the second would be an optimized replacement portfolio that allows EnCompass to select the resources that could most economically replace retiring coal. And we'd like to see a more diverse set of resource options that might include additional DSM measures, and then, you know, solar, both on and offshore wind and storage.

CHAIR MITCHELL: Okay. So thank you for that. And so just make sure I've got it. Were Duke to perform its analysis as you've recommended, what we have at the

end of that exercise is an understanding on a plant-by-plant basis as to when it -- as to when it would be -- when it becomes uneconomical; is that --

MS. WILSON: That was a unit-by-unit basis, but otherwise, yes.

CHAIR MITCHELL: Okay. Unit-by-unit basis. Okay. I'm with you there. Okay.

MR. FISHER: Can I take it one step further, if that's okay, because I think I might be interpreting your question as well as what kind of outcome would we expect to see that's different from what we've seen.

And I suspect that part of the process of using the sequential peaker method in the way that Duke has used it has resulted in additional value being put into the later retired units in a way that is not necessarily consistent with what we'd actually see in the future. So what we'd actually expect to see is as we retire units today, we replace the performance requirements of those with a new portfolio, and then we have a new assessment that happens in a future year as to what the remaining value is of the units that are coming in place.

And while there might be some changes to the value of those future retire--- of future retired units that changes by virtue of having changed our portfolio

today, it's not necessarily a substantially increased value on those on a go-forward basis. And it might actually be a substantially decreased value. If we have a really high renewable portfolio, you may, in fact, have a very low energy value to those coal units sometime in the future.

And so I think that running through the process that we're recommending, you'd actually see a substantially different portfolio of units retiring, and we think probably earlier than Duke has put forward right now.

CHAIR MITCHELL: Okay. Okay. All right. That's very helpful. I appreciate your follow up there.

Okay. And then Ms. Wilson, you indicated sort of second that you would -- that the actual model would optimize the resource mix going forward. And so how is that --

MS. WILSON: Well -- and let me clarify. Optimize the resource mix going forward in conjunction with that unit retirement date because Duke did optimize its resource mix, but only after it had determined the economic retirement path.

CHAIR MITCHELL: Okay. So that -- you kind of anticipated, you know, where I'm going. So just explain

that to me in a very basic way, sort of what Duke did versus what would happen were they to conduct the analysis as you have suggested.

MS. WILSON: Sure. So the economics of unit retirement have to do with two things. The first is the cost to actually operate your coal-fired unit, and then the second thing would be the cost of any replacement resources that are -- that would fill in after that unit retires.

And so, you know, today or even five years ago the cost of those replacement resources that we would suggest that Duke would consider, so solar, wind, battery storage, are higher than what the expectation is that those costs will be in the future. And so if you are overlooking the capacity optimization as it goes along with unit retirement, you are not considering the fact that those costs will be falling over time and taking into consideration when the cost of those replacement resources might become cheaper than the cost to operate your -- continue to operate your coal unit.

CHAIR MITCHELL: Okay. Okay. So a little bit more, help me understand what Duke did specifically versus what you would do, what you would have them do.

MS. WILSON: So when Duke was looking at its

replacement resources, it was looking at the cost of a CT. That's a relatively mature technology. There can be some decrease in cost associated with commodities, but generally that's expected to be relatively flat over time, particularly in comparison to solar and wind and storage which have been and will be continuing to fall.

And so when Duke looks out at various unit retirement dates in the future, you might anticipate that coal is getting more expensive, the cost of that replacement CT is staying the same over time, whereas when you're comparing the cost of retirement, say, in 2023 to a non-fossil portfolio, maybe the coal still looks good, but in 2024 coal might be getting a little more expensive, whereas your replacement portfolio is getting a little bit cheaper. And so you'll find that with those change in costs, maybe 2024 is then your economic retirement date for that particular unit.

CHAIR MITCHELL: Okay. Okay. All right. Thank you very much. That's very helpful. Okay. I have nothing further for these witnesses. Thank you.

MS. WILSON: Thank you.

COMMISSIONER CLODFELTER: Commissioner Duffley, anything?

COMMISSIONER DUFFLEY: Thank you for your

presentation. I have no further questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: Yes. Just one question, and it's kind of a preview for maybe the third topic we're going to discuss, but on one of your slides you did have this line tucked in. It's, you know, recognizing impacts on transmission loading and constraints as just one of the really hard things about all this modeling. I haven't heard you or anyone else elaborate on that and kind of give solutions to that. Does what you're proposing address that or just any -- you know, a few thoughts on where we are now with our modeling versus that constraint and where we should be.

MS. WILSON: Sure. Those things can certainly be incorporated into the current modeling in specific ways. And some of those are to set up different areas in the model that represent transmission constraints, so you can essentially set up the flows between different areas as being open or being somewhat limited to represent those constraints that might exist.

Other ways to do that within the model are to add interconnection costs to the cost of specific resources that might be added as replacements. There are a number of, I'll say, also transmission solutions, and

one of the benefits to technologies like solar and storage are that they are highly modular and you can construct them in any size essentially that you want. So they might be a solution to alleviate some of these transmission constraints, siting them in specific load pockets that could actually help power flow more efficiently.

And that's just, you know, a number of different things to consider. Duke would also have to use more sophisticated power flow models to map those constraints more accurately than what can be done in EnCompass or other similar types of models.

And if Jeremy has anything to add, I'd --

MR. FISHER: Yeah.

MS. WILSON: -- welcome his response.

MR. FISHER: Let me just add in one more step there, is that there are some circumstances in which either the retirement of a unit or the addition of new resources does cause a substantial change to the way that transmission is otherwise flowing. I think that's less likely overall in Duke's service territory where there is a substantial amount through interconnection than some of the utilities that we find in the West, where they're really quite long distances and singular transmission

lines between spaces where those constraints are both meaningful and highly expensive to potentially remedy.

I think for the most part what we've seen other utilities do, is they run these optimization models and then they look at the implications on their transmission system, see what kinds of remedies are required in order for people to go there and then tweak the results in order to be able to hit those remedies, and then you look at the final cost on the back side of that.

COMMISSIONER HUGHES: Just a quick follow up. Thank you for that, both of you. Your, I think, middle approach, Ms. Wilson, was adding the cost of transmission somehow into the model, and that's the one I'm particularly interested in because I was under the impression that there could be some very substantial transmission cost in Duke's territory depending kind of their resource mix moving forward, and that just -- I just wondered if that's going to need to be modeled more accurately in the future. And so, I mean, you know, to me it seems like you're second approach would make sense, and my gut feeling is that that could have significant impacts on the model, but I may --

MS. WILSON: So Duke does do this, as do most utilities to some extent, in calculating a transmission

adder that gets included with the capital cost of a specific resource that's selected. You know, the challenge there is that each of the resources, depending on where they're being cited, could have a very different transmission adder that needs to be associated with them.

Some of them, that interconnection cost might be zero, and for others it might be quite a bit higher, so depending on where the resource is sited, you know. Duke may need to get more granular with respect to that to take into consideration those differing interconnection costs.

COMMISSIONER HUGHES: Thank you for that. I appreciate it.

COMMISSIONER CLODFELTER: Anything further?

COMMISSIONER HUGHES: Nothing further.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: Commissioner Clodfelter, just one or two questions. Of course, you heard Duke today talk about, you know, moving to the use of the EnCompass system or modeling, you know, in 2022 and beyond. It's come up also in the course of your presentation. And, of course, that's supposed to provide additional capacity -- capacity expansion module, a

production cost module, and it's supposed to help in cooptimizing, you know, early retirement of the coal fleet, but what is it that you would state or suggest or recommend that EnCompass could do more than what they are articulating and stating that they intend to use it for? I mean, if you were to today sit back and look into that crystal ball to say what additional capacities that it needs or should evaluate in terms of attributes and concerns or costs, what would they be?

MS. WILSON: So in contrast to what Duke is doing now, which is a two-step or I'll say a two-model process, they use System Optimizer for the capacity expansion component and then ProSim for the production cost or dispatch component, which involves transferring the buildout that comes from System Optimizer to a different model for a whole new analysis. EnCompass has the ability to do both of those functions, and so there is no transfer of data from one model to the other. You're bringing everything under one platform, essentially.

The second thing that I would say that EnCompass has the ability to do better than System Optimizer is to model resources at a higher level of granularity. So the dispatch patterns for solar, wind,

and battery storage, there can be quite a bit of hourly variation. And I'm sorry, my husband is talking to someone behind. The pleasures of working from home.

COMMISSIONER McKISSICK: I understand. I get it.

MS. WILSON: EnCompass is able to better model those hourly patterns as well as any subhourly adjustments. System Optimizer uses something called a load duration curve, where it stacks its hours from periods of high load to low load and does the dispatch that way. So you might get an overestimate of the amount of energy that's coming from fossil-fired units, particularly coal, because you're representing something -- and I apologize for the hand motions -- something that looks like this (indicating) as opposed to something that looks like this (indicating), and varies, you know, day to day or hour to hour.

So, you know, there are certainly capabilities that EnCompass has that are an improvement over System Optimizer and allow for better integration of the types of variable resources that Duke is going to be adding to its system.

COMMISSIONER McKISSICK: Okay. And you mentioned earlier, I believe, in your comments about the

fact that one thing that isn't appropriately taken into consideration in methodology that's presently being used is decreasing costs that will occur in the future when it comes to wind, solar, battery storage. How do you appropriately analyze today what the rate and amount of decline will be in the future with any degree of accuracy beyond it being mere speculation?

MS. WILSON: So the only certainty that we have about the future is that it's going to be very uncertain. That being said, there are a number of publicly available forecasts that look at these costs over time in some detail. Most of them are largely in agreement about the direction of these decreases, though they vary somewhat in terms of magnitude. And so I think it's important to survey all of those sources. Duke also likely subscribes and purchases forecasts from third-party vendors. So it's important to survey the landscape of what people are saying about costs and to adjust their resource costs accordingly.

It's also useful to do -- we mentioned this and it's a topic for a later time period, but an all-resource procurement. It often occurs that the costs that actual vendors come forward with are much lower than what the utilities were expecting, and I think that's been the

utility experience in a number of different jurisdictions.

You know, when industry press is reporting on these procurements that different utilities have done, then it always seems like there's a buzz online about, oh, did you see this very low cost for wind or wind paired with storage or solar paired with storage. And so it's always helpful to survey the market and find out exactly what these resources are going to cost now to implement on your system.

COMMISSIONER McKISSICK: Thank you. Commissioner Clodfelter, I don't have any further questions. I appreciate you sharing your thoughts and perspective.

MS. WILSON: Thanks.

COMMISSIONER CLODFELTER: Okay. Thank you. Ms. Wilson, I think you answered the one question I had when you were answering the Chair's questions, but just to be sure I've got it fixed in my head correctly, the reason you say that Duke's process inflates the value of the later retired units is because it uses a benchmark that's fixed at the present point in time and not a benchmark that evolves over time. Did I get it correctly?

MS. WILSON: I think you're talking about two separate things.

COMMISSIONER CLODFELTER: Then correct me. Then why does Duke's process inflate the value of the later units retired?

MS. WILSON: Yeah. Okay. So when Duke is doing its analysis -- and there's a nice table in the IRP; I believe it's Table 11B that details, via many lines that go back and forth across the page, the direction that its analysis takes. And so as we know, Duke establishes a rank order, and then it retires those units over the course of time for over the analysis period.

The Allen units retire first. And in Duke's analysis, when the Allen units retire, that retirement date is locked in, so Duke's modeling then proceeds, assuming that the Allen units no longer exist, that they're no longer providing energy to the system. So that energy that would have otherwise been provided by Allen needs to be provided by some other unit further down the line.

And this continues to be true as Cliffside retires, as Mayo retires. And so again, those other larger units that retire later are forced in Duke's model

to pick up the slack because there's nothing else, there's no replacement resource that's been included in its modeling to generate that energy.

So if you look at Duke's analysis, you might assume because these later units are generating more because they're picking up the generation of these other units, that they are therefore higher value to the system, but if we'd been replacing those resources over time as they retire, as happens in reality because you have to be able to meet your reserve margin and serve your customers' annual energy requirements, that value would change because we might be getting more energy from solar, more energy from wind, and we don't need the coal units to be generating as much as we do in Duke's analysis.

And so what Duke is suggesting, that you add value to your remaining coal units as other units retire, and I would say that that's not correct. The operations will almost certainly change because of both the retirement and the replacement resources on the system, but that doesn't necessarily mean that those later retirement units are more valuable to Duke.

Oh. You're on mute, Commissioner.

COMMISSIONER CLODFELTER: Thank you. I'm glad

I asked because that was much different than my understanding and you've cleared me up. I suppose, in fact, if I'm thinking about it, if what's required as units retire is that the later units, the remaining units have to cycle more frequently, they could actually operate less efficiently at a higher cost potentially, could they not?

MS. WILSON: That's one possibility, certainly.

COMMISSIONER CLODFELTER: So there are a number of possibilities. Okay. I thank you for clearing that up for me. And that's all I had, so --

CHAIR MITCHELL: Commissioner Clodfelter, I have another question.

COMMISSIONER CLODFELTER: Okay. Go right ahead.

CHAIR MITCHELL: All right. Ms. Wilson, then -- so Commissioner Clodfelter asked you a question, and you said I think you're sort of mixing up two things. So you answered the question about the value of the sort of remaining units, but to his question about the Net CONE, using the Net CONE, just walk me through one more time your opinion as to that.

MS. WILSON: So Net CONE can be useful in certain regulatory dockets, and Duke mentioned that they

use it for avoided cost. The avoided cost docket is a value for capacity, and so that Net CONE is used to determine essentially the price for a new unit entering the market, so how much we pay to PURPA generators, or in PJM, you know, the price that someone looking to come into the market might receive. That's quite a bit different from the analysis that we're doing here where it's not just about capacity, but it's also about the energy that's being provided to the system.

And so the use of Net CONE as a benchmark doesn't take into account that energy value that you might be getting from other replacement resources, which can be much greater and I would expect to be much greater than a CT.

CHAIR MITCHELL: Okay. And so does the use of Net CONE preclude the system from -- just kind of walk me through the practical implication there, what -- because I just want to make sure I'm understanding exactly what your issue with the use of Net CONE is beyond what you've just told me.

MS. WILSON: So we talked about one use of Net CONE which is that it's not as dynamic as the cost of other resources. And so continuing to use a CT might push back a retirement date later in time because the

costs are staying relatively constant over time than might using the optimization with a different set of lower cost resources.

CHAIR MITCHELL: Okay. All right. I think I finally get -- I know you've now said that a couple times --

MS. WILSON: That's okay.

CHAIR MITCHELL: -- so thank you.

MS. WILSON: And I was going to ask if Jeremy wanted to chip in --

CHAIR MITCHELL: Okay.

MS. WILSON: -- in case we interpret things differently, which happens all the time.

CHAIR MITCHELL: All right. Finally got it. All right. Jeremy, you're up.

MR. FISHER: No. I was hoping to maybe give -- maybe a tangible example of this might be you can expect, for example, a resource like solar provides a substantial amount of energy relative to its capacity valuation, right, and so a replacement portfolio for a coal plant that includes, for example, a substantial amount of solar, say, paired with storage may, in fact, have a better value to Duke's system overall than a CT alone would.

So even once that CT is netted out for its energy value so that it becomes Net CONE rather than its Gross CONE cost, there are substantial elements that that replacement energy coming from solar plus storage bring to the system that you're not otherwise realizing from a gas CT alone.

So if we are really just comparing capacity to capacity, then maybe it's a reasonable benchmark to consider in that space, but we're not just comparing capacity; we're doing integrated capacity plus energy mechanism.

CHAIR MITCHELL: Okay. That helps, too. Thank you very much, both of you.

COMMISSIONER CLODFELTER: Thank you both for those last series of answers to several questions. They have been very helpful. I appreciate it.

MR. McDOWELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes. Mr. McDowell.

MR. McDOWELL: I would like to hear from Ms. Wilson again on her response to you. I was a little bit confused by it. She was suggesting -- all right. Let me talk to her, I guess. I guess you were suggesting in your response that the way Duke went through the process, the first retired unit, say it was Cliffside 5, is taken

out of the mix, that energy has to be made up by units already there, it's not replaced, and so automatically that adds value to all the existing units, including all the coal units.

So that kind of suggests that in their modeling, their run doesn't provide for the -- for reliability or their reserve margin requirement in that year that it was retired. Can you answer that again, because I was a bit confused by the response?

MS. WILSON: Sure. And this is why it's important that Duke separates into Steps 2 and Step 3. Step 2 is just the determination of what it calls its economic retirement date, and so it uses cost and prices. It is not building a reliable system. You are right. That step doesn't occur until Step 3.

MR. McDOWELL: Sure.

MS. WILSON: And so we're suggesting that those steps need to occur simultaneously, both the economic retirement date and the replacement resources, because they exert some influence over each other.

MR. McDOWELL: Okay. That's helpful. Thank you. I appreciate it.

COMMISSIONER CLODFELTER: Okay. Thank you both. We'll go back to Ms. Thompson and Mr. Smith, and

let me know if you had -- you only used about 35 minutes of your allotted hour in the presentation, so I don't know if you have other presenters.

MS. THOMPSON: No. Thank you, Commissioner Clodfelter. That concludes the presentation from our -- from SACE, et al., and CCEBA and NCSEA on this topic.

COMMISSIONER CLODFELTER: Then thank you. Thank you all.

And with that, we'll then move to Ms. Force for the Attorney General's presentation.

MS. FORCE: Yes. Good afternoon. Again, my name is Margaret Force. And for the Attorney General's Office I'd like to introduce you to Edward Burgess, who I don't see yet, but we will shortly. He has worked on the reports that were filed in this docket, along with our comments, and is the Senior Director for Strategen Consulting. He has extensive experience working with economic analyses, tech--- regulatory support, and resource planning, among other things. There are more details about his experience and qualifications in attachments that are already in the docket. So without further adieu, I'd just like to turn it over to Mr. Burgess.

COMMISSIONER CLODFELTER: Mr. Burgess, glad to

have you with us.

MR. BURGESS: Thank you, Ms. Force, and thank you, Commissioners. Can you hear me okay?

COMMISSIONER CLODFELTER: (Nods affirmatively.)

MR. BURGESS: Okay. And now I will attempt to share my screen, if I can be given permission to do so. Okay. All right. Can you see the presentation now?

COMMISSIONER CLODFELTER: Yes.

MR. BURGESS: All right. First, just a little bit about myself and my firm, Strategen. We're a professional services firm where I've worked for about six years, and I have about a decade of experience working as a consultant in the energy industry on a lot of leading-edge energy issues, including resource planning. We've worked with public and private sector clients around the country on technical modeling issues, strategic planning, and regulatory and public policy issues.

We've been fortunate to work with the Attorney General's Office on this Duke IRP proceeding over the last year and a half or so, and I will be presenting on two of the segments we have lined up, the first one being, of course, coal retirements, and then later on the grid impacts.

Regarding the coal retirements panel, what I want to cover in this presentation is a little bit about what we observed in Duke's modeling and some of our own recommendations regarding economic coal retirements and the use of endogenous selection which we recommend as a way to optimize resource additions and requirements at the same time through a comprehensive modeling process. We'll talk a little bit about some of the critiques we had of Duke's sequential peaker approach which had shortcomings in terms of the arbitrary groupings and rankings that we think made, you know, the results of that potentially suboptimal, and then we'll talk a little bit about some of our recommendations and recommended directives going forward.

So first, just to give a little bit of a review of what Duke's approach was in the 2020 IRP and what our recommendation was in evaluating coal retirement decisions, you know, of course Duke has the sequential peaker method which was conducted as a separate analysis, you know, prior to the core resource selection process. And, you know, this process, you know, I think as Duke has mentioned, is one that they developed internally. It's not, you know, sort of a standardized methodology. It was not integrated into the core IRP optimization

model. And in our view, it also introduced a lot of unnecessary steps that, you know, could introduce bias into the retirement date selection and so, you know, we'll talk a little bit about some of those.

In contrast, you know, Strategen and the Attorney General recommended a different approach that incorporates endogenous selection and optimizes the resource additions and the retirements within the same comprehensive modeling process. And so, you know, this allows for those decisions to be evaluated simultaneously. It doesn't, you know, require us to worry about, you know, some kind of hypothetical proxy unit like a peaker -- a CT peaker plant, and it doesn't necessarily presume, you know, what the replacement resource would be. You know, in some cases, you know, the coal retirements assume that there would be a default replacement of natural gas. And, you know, we think it also avoids some suboptimal outcomes that would be more likely in a sequential approach.

So what exactly does an endogenous retirement analysis correctly do and what are some of the limitations? I think we've heard a little bit about that with the last presentation, but, you know, I want to reiterate some of these issues. And an endogenous

approach does correctly optimize for a lot of the key cost categories that you would encounter at a coal plant, so that would include 100 percent of the ongoing fuel costs, 100 percent of the ongoing variable O&M costs, and it also does model, you know, most of the incremental capital investments and ongoing fixed O&M costs over many years or the plant's life, except for a small fraction of these which, you know, we see in the final years of the plant's life, you know, prior to its retirement date where, you know, there are some limitations in terms of how the modeling has to work.

So the limitations, you know, it may not correctly model that small fraction of incremental capital investments in the final years of the plant life. You know, this is due really to some computational issues in terms of how these optimization software tools work and are very difficult to, if not impossible, to resolve, but in our view this is kind of a small discrepancy that can be corrected through other avenues. And, you know, Strategen has recommended some of these other avenues that can be pursued to provide a more accurate result.

You know, one sort of note. You know, we're talking about some of the incremental capital costs. I want to make sure this doesn't get confused with what we

often refer to as subcosts or potentially stranded costs. You know, they're already incurred and, you know, it's -- our view is it's not appropriate to include any of those subcosts and stranded costs in a forward looking retirement analysis, and that's true regardless of whether it's endogenously modeled or not.

So the basic point is that, you know, the vast majority of these ongoing costs at the coal plants would be correctly optimized under an endogenous approach. You know, there are some minor limitations, but we don't think that necessarily outweighs the benefits of taking that approach in modeling, you know, most of the coal plant costs through the single-step optimization process.

We also heard a little bit about this, so I won't reiterate it too much, but, you know, there are other utilities that are taking a similar approach to modeling their coal retirements. PacifiCorp we heard about, and I think Mr. Fisher mentioned he wasn't as familiar with the 2021 IRP, but I do want to confirm that, you know, PacifiCorp is now using an endogenous modeling approach to its coal retirements in the most recent process.

They -- you know, they do have some simplifications that I want to highlight in terms of how

they do it. So, you know, rather than just letting the model select retirement dates in any possible year, they do sort of limit it to a few discrete years that could occur. So, you know, for example, Unit 2 of that hypothetical plant might be able to retire in 2023 or '26 or '29, you know, usually kind of coinciding with when they might have a major overhaul of that unit. And so, you know, that would ultimately be when you intend to see the model select retirement anyways to try to avoid some of those overhaul costs. You could look at every year. You know, that would be more precise. But, you know, that also increases the, you know, the computational requirements of doing it that way.

We also have been involved with the current Xcel Energy resource planning process, and so they don't have quite as a sort of granular approach, but they do have what's sort of an integrated model that actually uses EnCompass, and so they look at, again, not every year, but different potential retirement dates and that -- and, you know, fully model the different kind of fixed cost scenarios that would emerge from those different dates. And so to do that they have set up the model in a way that can sort of have each retirement date as sort of a different option to select, while sort of making sure

that that individual unit is only at -- you know, only in there one time in the model. It's not duplicating the unit in the model.

You know, Duke raised some, you know, valid concerns about endogenous selection, you know, as we sort of had our back and forth here with the comments and discovery. And, you know, for the 2020 IRP, I'll just note that, you know, they did -- they used System Optimizer, as we've discussed, you know, to optimize their resource selection except for the, you know, the large amount of resources that were preselected or forced in under some of the scenarios.

And I just want to point out that System Optimizer, it can do endogenous modeling of retirement dates. Duke chose not to use this capability, and the main reason why that they expressed was these ongoing capital and fixed O&M expenses of retirement candidate varies, you know, with that date, so it becomes this dynamic problem that -- I think is how they characterized it, and that the System Optimizer tool just can't do that sort of dynamic change to those expenses. And so, you know, I think while that's true, as we mentioned, you know, I'll explain in a minute, you know, there are some workarounds to this that could be explored either with

System Optimizer or with EnCompass or any other tool.

To just give you sort of a bit of an illustration of what we sort of mean, you know, why we're sort of leaning towards this endogenous approach, you know, we think it's important not to sort of throw the baby out with the bath water, if you will, in terms of these modeling choices and that, you know, the endogenous approach can still capture a lot of the important details.

And so just as an illustrative example, you know -- and this is a graph. It's just hypothetical. You know, what if we looked at sort of year-over-year costs of continuing to operate a coal plant. These are made up numbers. They're not, you know, reflective of any particular unit. But in this case we're looking at, you know, what if the model looked at an accelerated retirement in the year 2026 versus the year 2030, and sort of what, you know, this is trying to illustrate is that in that sort of 2026 case you still capture, you know, a lot of the cost savings from the retirement in the later years, which is shown by the red outlined bars. And then there's still, you know -- but there's a small fraction of savings that are not necessarily captured by the model, and that's sort of yellow over orange outline

in, you know, in those final years due to the computational limit.

So, you know, this is actually a discrepancy in the model and -- but we still think it's close to an optimal date because it reflects, you know, a lot of those important costs and benefits in those later years before they're, you know, after the retirement.

You know, if the model selects this 2026 date, you know, in fact, the actual cost savings could be higher than what the model showed, and so that actually leads us to believe this is a somewhat conservative approach to finding the date, and then these additional savings could then later be subtracted from the final result to give a more precise net present value for the, you know, subsequent portfolio analysis.

And so that was our recommendation, is, you know, you could sort of address these dynamic issues in the post-modeling step and still capture, you know, a lot of the cost and benefits of an earlier retirement.

So as I mentioned, you know, we offered a few solutions to addressing, you know, these concerns over endogenous modeling. You know, we came up with at least three strategies and provided some of these in a response to one of Duke's data requests, so I won't go into a lot

of detail here just because it quickly gets technical and in the weeds. I did include an appendix slide that folks can take a look at. But, you know, we outlined a scenario-based approach, a multiple resource method which would be similar to Xcel or PacifiCorp's approach, and then finally our sort of post-modeling adjustment which was what we recommended.

You know, all these approaches could be used to comprehensively model the retirement of all the coal units in Duke's fleet simultaneously. They would all, you know, automatically factor in reliability constraints. And, you know, as I mentioned, there's some more information about these in the appendix slide.

Just a few notes on Synapse's approach and the -- you know, using the EnCompass model. You know, we did want to note that Synapse used Duke's coal retirement dates rather than endogenous selection. Now, EnCompass is technically capable of doing endogenous retirements, as I mentioned. You know, it's our sort of understanding that part of the reason Synapse took that approach is to do more of an apples-to-apples comparison to try to mimic Duke's portfolio with as few changes as possible. That may not necessarily reflect, you know, what is truly optimal, but did want to note that and that, you know, if

EnCompass is used going forward, I think it would be worth ensuring that the endogenous capability would be used going forward.

Let's see. Just shifting gears a little bit, you know, back to some of the issues that we identified in Duke's sequential peaker method, I mentioned this briefly, but what's worth reiterating, that, you know, Duke included these groupings in its analysis and basically grouped units together in the sequential peaker approach and when it was coming up with its initial ranking methods. And so, you know, this really, I think, is an issue because it decreases the flexibility that the model has to choose a least cost pathway. You know, you're basically looking at much larger size of generation resources when you're thinking about retirement decisions, so rather than having the flexibility to maybe stagger retirement dates, you know, over a period of time, you have, you know, a big chunk coming off the system all at once, and that really increases, you know, the lumpiness of these -- of the replacement generation and I think has some distorting effects in the modeling.

So, you know, our recommendation was to look at the, you know, retirements on an individual basis rather

than these arbitrary groupings, you know, and recognize that, you know, I think, you know, Duke brought up some issues around how we might consider the costs that are common to some of these plants and, you know, I think that there could be some solutions there, but that shouldn't hold us up from looking at a unit-by-unit analysis.

I did want to comment, too, on the -- you know, not only the sort of economic dates that Duke ultimately selected, but the earliest practicable dates that were in their analysis and in Portfolio C. Their retirement dates there were based -- you know, several of the plans were based on a presumed natural gas replacement which, you know, it's not clear to us that that would necessarily be the optimal solution. You know, for 10 of the coal units the earliest practicable retirement date was set based on that presumed need to construct onsite natural gas capacity.

So, you know, the notion that that these new gas resources are necessary and optimal was more or less predetermined even before the model could identify what an optimal portfolio might look like. And I think this is increasingly relevant, these earliest practicable dates, since Duke has, you know, recently filed a

modification in South Carolina to its IRP which used these earliest practicable dates for its preferred portfolio. And so I think it's really important that we get a handle on, you know, how these dates are being selected and, you know, are they really necessary, or what are the limitations that driving those earliest practicable dates.

So the recommendation here as to the model, you know, when we're doing the economic modeling, you know, to allow it to sort of freely select any retirement date based on those economics alone, and then we could take a look later to say, you know, what are the -- what might an earliest practicable date be that's -- and then we could specify if there is some sort of true, you know, engineering limitation that prevents, you know, the units from retiring before a certain date, then we can look at that later. But it's still good to understand, you know, on an economic basis, you know, what the model would choose.

So just to kind of get to the conclusion here, in terms of some of the recommended directives that we would suggest, you know, one would be for -- to require Duke to implement endogenous selection of its coal resources in EnCompass or any other tool that ends up

being used as part of the core optimization process. If Duke believes that there are limits in the software, you know, regarding these ongoing capital expenditures, then, you know, there may be ways to address that, some of which we suggested. We recommended the Commission to require Duke to allow each unit to be retired independently in the model without these groupings or rankings. If --

You know, and I should mention, you know, it was brought up that the -- you know, one of our suggestions maybe was to look at the larger units first, and that didn't make sense to Duke because they didn't have -- because those were more efficient units or more valuable.

You know, I think it's important to think about -- I mean, the overall cost is still important in this case and, you know, we can think about, you know, which units are more efficient, but, you know, they all might be sort of less efficient relative to a replacement, so I think you really have to think about not only the marginal cost of these units, but what is the sort of magnitude of the generation that we're replacing to get to really the least cost in terms of the net present value perspective.

Third, if adjustments to retirement dates are made due to, you know, sort of certain practical engineering limitations, then I think that still it would be good for Duke to provide the results of the economic modeling before and after those adjustments. And then in addition, it may be beneficial to -- in addition to the sort of portfolio-wide modeling, to have that be accompanied by a unit-by-unit analysis, sort of similar to, I think, what we heard about in the last presentation, but that, I think, helps us really dial into, okay, which are the -- which are the kind of least efficient units on the system that we really ought to focus on, you know, getting off the system because they can -- you know, they're costing ratepayers more than we need to be paying. And so that would be helpful, I think, you know, as a sort of an accompanying step.

And then finally, you know, for additional transparency, this whole process allowing, you know, Intervenors the opportunity to conduct their own model runs. And there could be a few different ways to do that. One would simply be have Duke provide all the data and assumptions and their EnCompass model runs and that -- so others could basically have that at the same starting point and then make their own tweaks. That

presumes that Intervenors have the resources and expertise to do their own modeling. But, you know, as we have seen, there are some that have run EnCompass in this proceeding, and so that might be a possibility.

The other would be to require Duke to provide those, you know, model, license, and training to the Intervenors so that they can do their own runs.

And then third, you know, would be simply to allow Intervenors to make a request to Duke to conduct a model run with different input assumptions, and they would -- and Duke would produce those results on behalf of the requestor.

So those are just some of our thoughts on some possible recommendations going forward into this. And I think with that, I -- yeah. That's the end of my presentation on this topic, and I'd be happy to answer any questions you may have.

COMMISSIONER CLODFELTER: Thank you for that, Mr. Burgess. We'll start questions with Commission Staff.

MR. McDOWELL: Commissioner Clodfelter, I have just one question, I think, of Mr. Burgess, and it's basically the same question I had for Ms. Wilson. It's related to PacifiCorp's 2021 IRP which Mr. Burgess made

reference to.

The statement that I read to her out of that IRP was "New to this IRP is using the long-term model to consider the retirement of coal endogenously." Do you have any insights as to the value that PacifiCorp approved to making that change to do that endogenously? It may be in the IRP. I admit I did not read the whole IRP from early September, but I don't know, maybe you did and maybe they've made a comparison of what it was under the old techniques versus the new techniques. Do you have any insights there?

MR. BURGESS: Yeah. And I -- I've not followed the whole history going back to when it was, I think, 2013 that Mr. Fisher mentioned. But, you know, I think that -- and I've been involved with this cycle, but they did -- my understanding is that they have now returned to or implemented in this cycle the endogenous modeling approach in PLEXOS, the model that they're using. And so, you know, I don't know all the reasons why they maybe stopped doing that and went back to it, but, you know, maybe it has something to do with them now moving to this PLEXOS modeling platform or, you know.

But in any case, that is what they're doing. There are limitations to that, as I mentioned. You know,

they sort of have these kinds of discrete time steps that they use. There's other factors, like they have basically, you know, forced in some resources I think, you know, similar to maybe what Duke has done, so not all of the resource additions are sort of endogenously selected by the model, but I think that, you know, it is in many respects sort of going in that direction to, you know, an endogenous remnant that we'd like to see.

MR. McDOWELL: So you don't know when this 2021 cycle for them, if they did the analysis the old way and the new way and then compared them in the IRP, do you?

MR. BURGESS: I don't believe so. I -- you know, they had indicated pretty early on in the beginning of the sort of stakeholder process leading up to them releasing the final plan that they were going to use an endogenous approach. I think that was -- you know, they indicated that as -- in early 2020 and I think -- yeah. I mean, I think part of the reason is that they're just simply looking at, you know, the history from the last cycle where they did these unit-by-unit analyses, and there was -- it became pretty clear I think to a lot of the parties that there was a lot of uneconomic coal on the system, and so, you know, how do you sort of evaluate an orderly retirement to some of those units, and I think

the best way to do it is really through that comprehensive endogenous approach, so --

MR. McDOWELL: Okay. Thank you.

MR. BURGESS: -- I don't understand why they might have done it now, but that probably was part of the thinking.

MR. McDOWELL: All right. That's all I have, Commissioner.

COMMISSIONER CLODFELTER: Thank you. We'll turn to the Commissioners, starting with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Thank you, Commissioner Clodfelter. No questions at this time.

COMMISSIONER CLODFELTER: Okay. Commissioner Gray?

COMMISSIONER GRAY: Thank you. No questions.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: I have no questions. Thank you.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: Thank you. No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: Yes. I have one

question. A couple of you have mentioned how to treat some costs in your analysis, and I'm trying to wrap my brain around whether the revenue requirement treatment of some costs makes a difference because we -- there are different options for dealing with some costs. It's not a pure economic from a private company that invests in something. There is a process for recovering some costs. And is there a way of dealing with undepreciated coal value that could impact an analysis where Duke might have justification for including some cost?

Sorry if that wasn't clear. I'm still trying to wrap it around my head, the difference between the way the accounting for revenue requirements is dealt with and just a pure economic some costs can never be recovered, because they can be recovered under some circumstances.

MR. BURGESS: Yeah. That's a good question. I -- you know, as far as these models go, I mean, really the goal is to figure out what decisions do we need to make going forward, right? So we look at future costs, operating costs, incremental capital. But, you know, the presumption is that all those subcosts, those are decisions that were made in the past; we're not going to change those now. You know, there is the question of what does that mean for cost recovery of those resources

if they retire early. I mean, in some respects that's partly a decision, you know, the Commission will have to make about, you know, do you do something different in terms of accelerated depreciation or securitization. You know, there's different avenues for that.

I think, you know, one thing, though, I would -- to keep in mind is that I think from a utility's perspective, there -- you know, there is some potential risk that they would face, you know, under an early retirement scenario about whether or not those costs are recoverable, and so that may be leading them to want to find a modeling outcome that fairly closely matches the retirement dates with the depreciation schedules because otherwise, you know, it's a little uncertain what's going to happen. More kind of that -- those kind of choices can be laid out. Maybe there's, you know, more room for flexibility on how we treat, you know, different retirement dates.

COMMISSIONER HUGHES: Interesting. Thank you. No further questions.

COMMISSIONER CLODFELTER: Thank you. Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: Thank you. And Mr.

Burgess, I have nothing for you, either. Thank you for your presentation. Ms. Force?

MS. FORCE: I just want to thank you for the opportunity for our participation.

COMMISSIONER CLODFELTER: We appreciate it. We appreciate it. We'll hear from you on a later topic.

MS. FORCE: Okay.

COMMISSIONER CLODFELTER: And that means Ms. Edmondson, you're batting cleanup.

MS. EDMONDSON: Yes. Last, but not least, we have our panel. Let's see when they'll come on. Here they go. Jeff Thomas, Dustin Metz. Both are engineers with our Energy Division. And then Bob Hinton who is Director of our Economic Research Division. And Jeff is going to drive the presentation.

COMMISSIONER CLODFELTER: Great. Good afternoon, gentlemen. Take it away.

MR. THOMAS: Okay. Are you able to see this all right? See if everyone can see me and hear my presentation?

COMMISSIONER CLODFELTER: You're coming through loud and clear.

MR. THOMAS: Great. Okay. So one of the benefits of going last is that much of the material has

been covered already, so I will hopefully be brief and focus on the unique perspective that the Public Staff is bringing to this, so as the Public Staff has identified in our comments, has been -- my name is Jeff Thomas with the Energy Division.

And so the difference between exogenous and endogenous coal retirement is essentially just how that retirement is treated, whether it's done within the model or whether it's specified outside the model and input into the model. And so the Public Staff thought we believe that there's value in determining those retirement dates within the model based upon, obviously, some considerations that have to be taken into account. And Duke has -- and the Intervenors and the AG have addressed many of these, such as, you know, the complexity as you consider these multiple permutations of retirement dates and timing. These models can get very complex to solve and take hours or even days to run.

And then whether or not you retire just coal, or some models are actually able to look at endogenous retirement of even new units as they come in, or natural gas or existing solar or battery, so you really have to focus on the types of units that you believe could be economically retired, and then also how important those

retirement dates and what external factors affect those dates. So, you know, practical limitations are not always captured by the model. I'll get into that a little bit more, and it's already been addressed to some extent. But, you know, the model is an imperfect representation of reality, and oftentimes the model just doesn't know things that system planners know, and those -- sometimes those complications and those factors can't always be translated into linear optimization, which is the basis of all of these models.

So we've been through this several times now and I'm starting to memorize this diagram, but the coal retirement obviously in Duke's 2020 IRP is this four-step process, with Step 1 and Step 2 kind of happening separate -- it's this sequential peaker method -- to establish those dates, and then the output of that analysis is fed into the portfolio optimization. And so this is the exogenous portion that I'm speaking of, when you take those outside results and then you put them into your portfolio.

Now, this is the sequential peaker method, the Step 2. It's very iterative, and Duke in their IRPs did a great job of explaining exactly how they ranked those coal units for the sequential peaker method, the statute

-- the standards by which they evaluated them. But for each unit that date is, you know, locked in and then the model is run and this analysis is completed to finally arrive at that date, and then that unit is locked in and then it's repeated.

And so the Public Staff in our comments, we really identified two main concerns with this. First, as as other Intervenors have noted, is only combustion turbines are considered as replacements. I think Ms. Wilson did a great job in explaining why that is not optimal because the cost of a CT is relatively standard, it's relatively steady, it's a mature technology, versus alternative replacements such as storage or solar, those can -- those costs curves are declining much faster, and so the date that you have to build those retirement units obviously affects the cost of that retirement. And so if you're evaluating your net benefit and your retirement date based upon a CT, this could result in a less than optimal retirement date.

And then also another, you know, thing to note is, you know, the retirement -- this method really just looks at each plant in isolation. And so, for example, you know, in general, the retirement dates that Duke found in this method aligned with their ranking of the

units in terms of usefulness, except for the Roxboro 3 and 4 were retired before Units 1 and 2.

Now, what this does is now you've locked in a Roxboro 1 and 2 retirement date, assuming that 3 and 4 are operating to the end of their depreciable life, but now you've run the Roxboro 3 and 4 sequential peaker method and you've actually retired it before 1 and 2. So now that does call into question whether the Roxboro 1 and 2 retirement date was accurate and whether it was not -- in fact, there was some interaction between 1 and 2 and 3 and 4 operating simultaneously that maybe caused the suboptimal result. So these are all just concerns with the sequential peaker method.

Certainly, the Public Staff believes that the sequential peaker method was generally reasonable for planning purposes and there was a lot of analysis that went into these dates. By no means is it a -- is it an unreasonable methodology, but we believe that the endogenous retirement methodology where you are able to find both the when and the what simultaneously could provide benefits to ratepayers in terms of establishing those truly economic retirement dates.

So many models that actually include endogenous retirement, does include it as an option, a toggle you

can turn on and off. And as I've already spoken to, there are benefits with using that option and that's one of those that you're using the same assumptions to pick your retirement date as you are to pick your resource replacement. That can be fuel, capital cost, and in general I believe Duke used many of the same assumptions, but there are some external assumptions that conflicted with the capacity expansion model, primarily, you know, the sequential peaker method, assuming that Roxboro would be replaced with a CT. And, in fact, Roxboro was replaced with a combined cycle in the capacity expansion model. So endogenous retirement would attempt to resolve some of those with some -- obviously, there are some trade-outs there which I will get to.

And then it does require -- the benefits of endogenous retirement is it does allow you to select from a suite of resources that can replace that, and you're able to take into account build schedules, how much time it takes to deploy some of these resources, if there's any included interconnection costs that must be considered, and then as well as your unit commitment during the replacement process.

That was some of the challenges, as I've already spoken to, the complexity, and the model solve

time is one factor. And then, you know, as I've said, there are some practical factors that the model is -- sometimes it doesn't know that unless you teach the model, is if you just let the model solve with economic retirement of coal units, it can ignore important factors such as the transmission support or ancillary services that are provided by those coal units if those are not constraints within your model, timelines to build and obtain permitting.

As we saw -- for example, as we saw in Dominion's 2021 IRP update, their Plan A utilized an endogenous retirement option. And while the Public Staff has not yet filed its comment on that plan, it didn't open -- that that plan actually retired 2,500 MW of mostly coal in 2023 almost immediately upon the model starting. And, obviously, that's -- if that's truly economic, the Public Staff still has some investigation to do on that and as -- other Intervenors as well, but obviously that -- we have concerns with that much coal being dropped off the system all at once and whether it's practical to be able to replace that and keep the system reliability to a level that customers expect.

And, also, some of the challenges here are simply untested results. It's one thing to go from using

a model that the utility is familiar with and turning on the endogenous retirement option, but at the same time, if Duke is attempting to transition entirely from System Optimizer and ProSim into a single model that has both capabilities of expansion planning and production cost modeling, and so the utilities have to become comfortable with that model as well.

You can't just type in all your inputs and press run and then go shut down Allen the next day because that's what the model tells you to do. You really need to understand what -- why this model is making these decisions, and you need to be able to see into the black box, as it were, and do additional analysis based on those results, like detailed unit-by-unit analysis of, you know, the first few retirements that are selected by the model just to ensure that those dates are robust under a variety of planning assumptions, price scenarios, and that you can maintain system reliability perhaps using even more advanced models such as SERVM, the Astrape model that was used to calculate some of the load following under additional solar scenarios in the avoided cost docket.

And then also endogenous retirement, as I've said, added a lot -- adds a lot of complexity and model

solve time and obviously tradeoffs, but sometimes this may not be necessary. Maybe they're -- maybe retirement dates have already been set by legislation or maybe there's only a couple handful of plants to retire and you've already retired most of the older coal units, so the utility has to, and regulators have to look at, you know, how important it is to economically select these dates as well when they're considering the added complexity.

And so we've kind of been over this a little bit, but I just wanted to, from our perspective as well, there are some plans, you know, that don't use endogenous retirement. Obviously, System Optimizer, one that does not. The DIEM model which was used in the Clean Energy Plan from Executive Order 80, this also did not use endogenous retirement. The retirement dates for coal units were selected based upon a variety of scenarios for retirement that were proposed and used in that plan, but those were selected outside the model and input into the model.

And then there are many national models, large models that use endogenous retirement or at least have the option such as the ReEDS model, which is a well-known model maintained by the National Renewable Energy

Laboratory, as well as NEMs, which is used by the Energy Information Administration. That is the underlying model for the annual energy outlook. And so that has an option to retire endogenously most thermal units, although most new technologies do stick around for their entire lifetime.

Obviously, EnCompass has the ability to use endogenous retirement, and Duke is considering now whether to use that -- although some utilities have used the EnCompass model, such as Xcel Minnesota. We spoke to the Minnesota staff, who also has EnCompass license, to analyze those IRPs, but, you know, those coal retirement units are set by -- have to be approved by MISO and often have to meet certain MISO requirements, and so they did not use their endogenous retirement option in the last IRP that they ran, despite having the capability.

PLEXOS obviously has the capability, as PacifiCorp in 2021 used in their P02 portfolio, and the Dominion 2021 update used endogenous retirement, but only in Plan A. It’s also referred to in Dominion’s plan as economic retirement, but essentially they're the same thing here in terms of the modeling and how the model selected those dates.

And then also the Brattle Group, who has done a

lot of analysis in the utility industry, has an Xpand model, and that model also has the capability to model coal retirements endogenously.

` Okay. And so finally, I was not able to build any slides off this, but the Public Staff is -- we're exploring actually obtaining an EnCompass license as well in advance of the 2022 IRP, and so we sat down with Anchor Power Solutions' staff for a training session on the 28th to better understand some of the retirement functionality. I was unable to get those slides into this presentation, but I just wanted to kind of explain some of the features that we found interesting in the EnCompass model and some of the limitations found.

So obviously, you know, Duke's noted the complexity of the what/when decision, but, you know, we feel that the -- at least from our short experience working with the training in the EnCompass model, that there are some guardrails there that can help provide additional accuracy to endogenous retirement, while addressing some of Duke's concerns about dynamic -- the dynamic capital CapEx in coal plants, as well as the selection of resources and the many different permutations.

So first, the -- as Ms. Wilson specified, you

know, EnCompass works by essentially comparing the benefits provided by a particular unit to the cost of operating that unit. And so depending on the unit of time in which you optimize over, you look at net benefit over that entire period. So if you're only looking at a single year or two years, it's very easy for a coal unit to be endogenously retired because it just takes a mild weather winter for that unit to not generate much benefit. Meanwhile, the CapEx and the O&M can be substantial.

So generally, if you use a longer optimization period, you'll really capture when those units truly do fall outside of their net benefit to the ratepayer to the system. But, you know, using a shorter time period can also provide additional granularity and you can -- a shorter time period allows you to specify more time periods. Instead of using, say, a three-season model with 12 representative hours, you might be able to use a four-season model with a full 24-hour day of the week, weekday/weekend granularity.

And so really, you know, you would expect that the endogenous retirement of coal in EnCompass would be multiple model runs, perhaps a longer capacity expansion run to truly find when those get in the ballpark and then

shorter runs to kind of narrow down on what really is the best date for retirement.

And so obviously, as I've already talked about, the models don't always capture constraints that exist in the real world, such as transmission constraints, planning, regulatory constraints, interconnection, queue reform, things like long -- outage schedules for transmission upgrades, and we see that in Dominion's plan where a lot of capacity was immediately retired in 2023.

But EnCompass does allow you to put in certain guardrails in that to address those concerns, such as limiting the amount that can be retired in one year, with the recognition that it's difficult to build enough replacement generation in a certain year. And you can also, you know, place reasonable restrictions on the amount of new capacity that can be built to replace that, which also would have the effect of limiting retirement. If your model wants to build 10,000 MW of solar in a single year to help replace retiring 2,500 MW of coal, obviously you're going to have to put reasonable bounds on the amount that you can -- of solar that you can interconnect each year.

You can also place restrictions on specific units. So you might say that certain units have to be

retired by a date certain if you had, say, legislation that set an end date. You could also say we know that we can't retire this unit until 2025. And the model can handle that as well; it can exclude a certain unit from retirement until a certain year based upon practical considerations.

You know, you have to make sure, though, that those restrictions that you place are reasonable and based in reality, because the model is simply selecting the most economic retirement dates that it can, and so you want to make sure that any constraint you add on the model is going to increase costs, and so you want to make sure that those constraints are reflecting reality. Otherwise, they're going to themselves produce an uneconomic portfolio.

So the model -- so Duke did adjust the dynamic CapEx schedules, and that is a legitimate concern. The dynamic CapEx spending on existing coal, that feature does not exist in EnCompass. You can put in discrete CapEx expenses that you have in particular years that are above and beyond any fixed O&M, but generally the model will then respond by trying to avoid those costs. And so you can't then -- the model won't, by itself, adjust that to go -- you know. to eliminate that spend or to have

some sort of ramp down of CapEx.

So these are things that probably could be addressed through iterative modeling of these retirement dates to play with that feature and to better understand it, but the Public Staff recognizes that that is a concern, but at the same time we want to make sure that we're not missing the forest for the trees. And if that dynamic spend is capturing, you know, a certain amount of $10 million of cost that may not have been included, but at the same time we're saving $1 billion by retiring these -- by using endogenous retirement dates, obviously we need to put things in perspective and do what's benefi--- what's best for ratepayers over the long term.

A couple other interesting things that EnCompass can do is they can actually create so-called retirement projects where the retirement of a unit might be set by a certain date, but the model can optimally select from various options, such as an example that was shown to us was three options for a coal unit, either keep the coal unit running, retire the coal unit by a certain date, or convert the coal unit to natural gas. And then you could also include, say, a carbon caption sequestration scenario for the right type of circumstances. So that kind of alternative scenario

analysis is already embedded in EnCompass and can be used to help facilitate the endogenous retirement by providing the model with different options which can then be selected and the most optimal option selected.

In addition, EnCompass can also, through sensitivity analysis, can explore the benefits of securitization by creating different retirement -- different rates for the different debt and equity ratios and different rates for debt and equity. The model can actually explore that, okay, it can pick a retirement date based upon no securitization, but then it can also -- now you can explore what would happen if you had a certain amount of securitization, maybe that changes the optimal retirement date, maybe it simply reduces the net present cost of an entire portfolio through less debt payments.

So this is something that -- another feature of the model that I think could play into the endogenous retirement feature and provide a better picture of the optimal way to retire the fleet. Not just the dates and the replacement, but what we do with the unamortized balance, how we minimize rate shock on customers who, you know, who might be simultaneously paying for both the replacement resource as well as the retired coal unit.

So overall, you know, the -- implementing an endogenous retirement in EnCompass, it is -- it seemed -- it appeared fairly straightforward in that the demo that we went through, though obviously the full data set that Duke will be using will be more complex and there will be more interactions between these, and it will increase the amount of time that the model takes to solve, and obviously it will create -- it will have the effect of -- and to a certain degree it will be a black box. You put your inputs in the model and the model spits out these retirement dates.

And so, you know, the Public Staff hopes that by having an EnCompass license and being able to explore deeply the assumptions that underpin those endogenous retirement dates, if used by Duke, and then we should be able to kind of peel back the layers of that black box.

And so endogenous -- just a closing remark. You know, endogenous retirement, it's -- in resource planning it's not new, but it is new to some utilities. And as I said before, you know, the utility has to become comfortable. The regulars have to become comfortable that the endogenous retirement is built upon a sound data set, a sound input data set, sound assumptions around both practical limitations and just the economic and

operational characteristics of the units that are loaded into EnCompass, but I believe it's a useful tool for holistically planning this system, and I believe that the benefits against the sequential peaker method or other exogenous methods could provide a much more ideal and optimal retirement schedule for coal for ratepayers. And that's my -- that's what I have.

COMMISSIONER CLODFELTER: Thank you. Mr. Metz and Mr. Hinton, I assume you're available for questions, but not presenting independently; is that correct?

MR. METZ: That is correct.

COMMISSIONER CLODFELTER: All right. I will tell you one thing, I'm very glad we made the decision to record this and transcribe it because Mr. Thomas, you covered an awful lot of material in a very short time, so I'm glad we have it -- we're going to have it down on paper so we can review it.

And with that, we'll see if we have questions. Unless there's any other presentation, we'll see if we have questions.

MR. THOMAS: No other presentation.

COMMISSIONER CLODFELTER: Mr. McDowell? Okay.

MR. McDOWELL: I think it's extremely valuable that Public Staff was able to attend the kind of overview

of that because I think Jeff's comments were very appropriate in this. I have one question. The Public Staff recommended that Duke consider implementing stochastic optimization in its expansion model, stochastic optimization.

Now, I have a -- I have a friend that got this doctorate in mathematics and statistics from Clemson College -- University, I guess, and I was going to ask him about stochastic versus deterministic, but ever since NC State won the football game last weekend that resource has dried up, so I would like to ask the Public Staff to explain that statement that they commented, recommending Duke consider implementing stochastic optimization. Can you explain that in very simple terms that even Commissioner Clodfelter can understand? What's different about this and the current modeling employed by Duke?

MR. THOMAS: Sure. So I'll start off first by saying that EnCompass does have the ability to use stochastic optimization. It's kind of the last envelope within their modeling paradigm. But essentially, right now I believe this comment was made in regards to carbon policy in our comments.

But essentially, right now Duke assumes, their model assumes that a carbon price will start their Plan

B, the Portfolios B and beyond, assume that a carbon price will start in 2026 and will escalate by $5 a year and to infinity until the end of the modeling horizon. And that's a deterministic model. That is certain. The model knows it's going to happen, so the model can plan for that.

But the problem is, as we all know, we've all been anticipating this carbon price since 2009, so we don't know when it will start and we don't know if it will be $5 or $20 or $1, and we don't know what the escalation rate is. There's a lot of uncertainty there. And so stochastic optimization is essentially you're building a portfolio considering that uncertainty, okay, but you may not produce an optimal portfolio for any particular final -- what actually happens, but you're trying to minimize your regrets, right? If we assume that a $5 carbon price is going to be enacted in 2026, and Duke plans its system for that based on that deterministic modeling, and then there's a carbon price of $100 implemented in 2024, obviously, the system that we've built is not going to be optimal anymore. We'll have regrets. All those natural gas plants will have to be shuttered, and we'll really have a lot of costs that are going to linger because of that.

And so stochastics tries to -- essentially, one way to test stochastics is to do what's called a Monte Carlo simulation where you run many, many, many scenarios with many, many different outcomes from that carbon pricing, and then you try to find an optimal portfolio that's most optimal for most of those scenarios.

Oftentimes stochastic optimization you'll build a scenario tree where if this happens, then we assume the next choices are, you know, if A happens, then our next choices are B or C, but if A doesn't happen, then our next choices are D or E. And you try to optimize over that entire suite of choices to give you a single portfolio that best positions you more to respond to that uncertainty.

MR. McDOWELL: That was an excellent explanation. So does that have implications on the retirement analysis that we're focused on here?

MR. THOMAS: So certainly. So if you were to -- so that's a great point, actually, because let's say Duke were going to do stochastic optimization based on uncertainty only in carbon policy. Well, if they did their sequential peak method, then they're going to pick retirement dates for those coal units based on that outside analysis. Then they're going to put those dates

in and they'll be unchangeable. Those dates will not be able to be adjusted based upon the carbon pricing.

But if you were to do endogenous retirement and the stochastic optimization based upon carbon policy, then your retirement dates of your coal units are going to adjust on the fly based upon the carbon price that's actually used in each determinant age stochastic scenario.

So the hope is that if you couple both of those techniques, the endogenous retirement and the stochastic modeling, that your model would select for you retirement dates that are -- that put Duke in the best position to respond to both a delay in carbon pricing or an acceleration. And the thing to remember there is that, you know, let's say you run that model, you build a 10-year plan based on that stochastic optimization. In 10 years you might look back and say, well, now that we know what happened, what we did, the dates that we retired those plants, well, it wasn't ideal, it wasn't totally optimal, but you built the most optimal plan for the uncertainty.

It's like carrying a rain jacket out with you when you don't know whether it's going to rain or not. You have to carry the jacket with you and it's not

optimal. You don't want to carry the jacket. And if it's sunny, you're going to wish you hadn't brought the jacket. But if it were to rain, you'd be glad that you brought it. And that's the type of least regrets of planning that can sometimes accompany that stochastic optimization.

MR. McDOWELL: Thank you very much. I better quit there while I'm still in good graces with Commissioner Clodfelter. Thank you.

MR. THOMAS: You're welcome.

COMMISSIONER CLODFELTER: If you ever were. Let's see if Commissioners have questions. Commissioner Brown-Bland? You're on mute. You're on mute. No questions?

COMMISSIONER BROWN-BLAND: (Shakes head negatively.)

COMMISSIONER CLODFELTER: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions, sir.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: Just a quick one. Mr. Thomas, thank you for the explan--- I mean, thank you for your presentation in general and thank you for your response

to Steve's question. That's very helpful for my understanding and I appreciate your thoroughness.

Help me understand sort of real-world implication here. If Duke were to transition to the type of modeling that you are -- sort of the type of process that you are advocating and sort of similarly that Ms. Wilson seems to be advocating, what does it do to sort of real-world ability to construct facilities that are going to be necessary to, you know, to meet the utility's needs? Do we -- and I just -- there may be a really good response to that question. I just wonder, you know, if it's -- you know, the utility needs lead time and, you know, sort of has to make certain choices at certain points in time to get those facilities constructed and into service. Do you all see any problems with the approach that you're advocating, problems specifically with the utility's ability to construct and meet its needs? Does my question make sense?

MR. THOMAS: Yeah. I think so, but I -- you know, I understand the, you know, the concern, right, is that we're going to layer all these complex modeling tools in there and then, you know, we're going to see drastic changes in the capacity expansion plan every two years based on, you know, whether or not some certainty

is resolved and things of that nature.

So I think -- just to take a step back, I think, you know, Duke has -- you know, you can't build a combined cycle in a year, so we have to understand that certain decisions have to be made in the face of that uncertainty. And so using endogenous retirement and, you know, specifically also the stochastic optimization, you know, that's going to give you in -- right now, when I run that model right now, it's going to say based upon the uncertainty that you're facing, this is the best plan. And if that plan says to build a combined cycle in four or five years, you kind of need to get started on that.

And if three years into the building when you're about to turn on that combined cycle, if that carbon pricing you thought was going to turn on suddenly doesn't or maybe it's stronger than you expected, your hope is that other aspects of the plan have kind of hedged your bets. Maybe you've built more of a certain resource to anticipate that carbon price moving one way or the other.

So I think there always is going to be a time at which a line in the sand has to be drawn and a resource has to be built, but the purpose of this

modeling is to build a plan that's robust enough in the face of that uncertainty, that once you've built the unit and turn it on, you don't have regrets because of the way you built -- the way you've optimized the rest of your system.

CHAIR MITCHELL: Okay. And that's a very helpful explanation. Mr. Metz, did you want to add something?

MR. METZ: I think the overall model aids in understanding of when I need to start planning new generation resources which would go into siting, and it also has to complement how the utilities have to plan their transmission system. So I think it's is it the chicken or the egg. But this is a first point where the utility can identify and say, hey, we need to retire a resource; if we retire it, what do we need to do in its absence? Where do we start building generation? How do we have to start building a transmission system?

CHAIR MITCHELL: Okay. All right. And listening to you explain this, Mr. Thomas, I realize you answered my question when you presented to us, so thank you for going through it again for me.

MR. THOMAS: Sure.

CHAIR MITCHELL: And thank you Mr. Metz.

COMMISSIONER CLODFELTER: All right. We'll move to Commissioner Duffley.

COMMISSIONER DUFFLEY: Thank you. I have one question, and it's with respect to your black box comments and your concerns about this black box, and other speakers have talked about the lack of visibility of this model when it spits out Allen needs to retire at this point in time. What suggestions do you have to combat that lack of visibility on how did the model come up with its choices, basically?

MR. THOMAS: Sure. So there's a couple different things that can be done. So the Attorney General made a great -- the Attorney General's presentation had a great suggestion just to allow Intervenors more insight into the model by Duke providing those inputs or somehow modeling licenses being made available, being able to just open up the model and look specifically at all of the -- all the inputs and assumptions. And what's nice about EnCompass is that all of that data can be exported to Excel in a way that wasn't really always the same with System Optimizer. So you could print out all of the fields, all the parameters, all the variables, and let people pour over that through Excel.

But I would say, you know, as these models get more complex, it's this black box method, and the problem is becoming -- it's just going to get worse. We've talked about that in ISOP stakeholder conferences. I would say, in my opinion, one of the greatest ways to peel back that problem, the black box layer, is through sensitivity analyses.

And so Duke often does these kind of high level, you know, low fuel, high fuel, low carbon, high carbon capital cost sensitivities, and really I think doing analysis on that and comparing those results can help you understand what's really driving particular retirements, you know, having multiple fuel forecasts embedded in there at different levels or changing capital cost of particular resources and -- will help show how the linear optimization models that are used to underpin EnCompass are making their decisions and where those are being -- where those choices are being made, because they are complex. But, you know, sometimes, you know, what -- you know, the sensitivity analysis results that Duke has presented in the past are often presented kind of, now, we ran some sensitivities and here's a difference in NPV and then they move on. And that's fine, and we do our own kind of analysis of those results as well.

But I think really kind of digging deep into those and using those as a tool to explore why a coal unit was retired on a certain date, is it because gas is cheap -- so cheap in the future, is it because replacement resources are getting more -- are declining in cost faster than the -- than expected or -- and all those kind of features, and a little bit deeper dive into those results I think can help peel back some of that.

But it's always going to be a black box, but looking into the model and looking at how important variables change results can really help you kind of peer inside that.

COMMISSIONER DUFFLEY: Thank you. That was very helpful. I don't have any other questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions. Thank you.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: Just one or two questions. And first, I'd like to say I really appreciate your presentation. It was very thoroughly done. And I'm glad to see that the Public Staff does have a license and that they're getting the training they need to use EnCompass as a model.

Now, let me ask you this, you talk about the functionality of EnCompass and I've heard a lot about that today, but based upon your communications with Duke, to the extent there have been communications with Duke related to EnCompass, do you see them using the functionality of EnCompass to take into account the exogenous retirement type factors that you articulated a need for them to utilize moving forward?

MR. THOMAS: So I think Duke -- as they've shown today, Duke has talked today a lot about their method, the sequential peaker method, and I believe Duke believes that that was -- it is a very robust method and it required a deep analysis of operational cost and dynamic CapEx, so I'm not trying to disparage that method, and I think Duke may decide that they want to stick with that method going forward into 2022. They've not really said one way or the other I think what they plan to use, but I think from today's presentation, I believe that Mr. Snider and his team would prefer to use that methodology at least at first.

But, you know, as I said, you know, it does take additional effort to try that endogenous retirement. Dominion was able to present one scenario with endogenous retirement, and I think I would -- I would like, and we

still have to have conversations about this with Duke between now and September 2022, but I would like to see at least some portfolios or at least some sensitivities which do include this endogenous retirement with some of the practical considerations implemented and reasonably justified. And that will take extra time and effort on Duke's part, and I recognize that, but I do believe there's value in at least exploring it in 2022, and depending on how the Commission views it, perhaps having some of the primary portfolios rely on endogenous retirement instead of the sequential peaker method.

COMMISSIONER McKISSICK: My observation today, based upon the presentation we received, and I thought about asking them a question about it in particular, was whether with the adoption and moving forward with EnCompass they still plan to primarily use the sequential peaker method. But it sounded to me as if that was still the path they were headed down; it's just that they saw other potential uses and variables that could be utilized by moving that way.

Now, let me ask you this because, I mean, obviously you can go in and you can deal with things dealing with the, you know, exog--- my gosh, getting ready to mispronounce the word -- but what I'm truly

trying to drill down to is this, if you go out there and model all of this and you look at all the variables that are there, and even if you assume the same type of assumptions that Duke is making about moving toward, you know, combustion turbines, at any point in time in using EnCompass can you then also look at what potential stranded costs would be if you end up with these combustion turbine units out there at some point in the future? Obviously, you're extrapolating and going pretty far out in time, but does it have that functionality?

MR. THOMAS: That's a good question. I'm not entirely sure, to be honest. The EnCompass model is quite complex and we've had -- I believe Duke has probably had more conversations about the general functionality of the model with Anchor Power Solutions than we have. But our focus is particularly just focused on the endogenous retirement function. But if it's not something that's built into the model, certainly it's something that can be done post hoc after the model has been run.

But generally, when you're determining your optimal retirement dates, the sunk cost, the unamortized balance of plant, is -- it's typically not a factor in that decision. How do you deal with those costs going

forward, how you allocate them and how you recover them, whether you securitize them or you accelerate depreciation, those are more ratemaking questions because the assumption that the model has is that those unamortized plant balances or stranded costs, they're going to be paid by ratepayers one way or another. They're not going to be disallowed, in other words.

And so that assumption says, you know, don't make decisions now based upon money that you've already spent because that will lead to suboptimal solutions.

COMMISSIONER McKISSICK: So what you're indicating is that whether you securitize the debt for the early retirement of coal generating facilities or whether you look at potential stranded costs that could be involved if you moved the combustion turbine route and have to deal with how that impacts ratepayers at some point, those are all going to be separate independent matters that would not really come to play in utilizing EnCompass as a tool, is that correct, or that -- but at the same time you said it could be kind of layered on as a variable, but it's an independent decision that's probably made concurrently, but it's --

MR. THOMAS: I think --

COMMISSIONER McKISSICK: -- but it's not really

a part of what EnCompass would typically be used for. Is that what I'm hearing?

MR. THOMAS: I think so. And I just wanted to make sure, just to understand and make sure I'm understanding your question. So you're saying if -- not -- you're not so much talking about the stranded assets of coal once we retire; you're saying if we build a bunch of combined combustion turbines now and then in 15 years we find that we actually need to early retire those and build replacement resources then, you know, what happens then? Does EnCompass consider that?

COMMISSIONER McKISSICK: At the outset. That's correct. I mean, if --

MR. THOMAS: Yeah.

COMMISSIONER McKISSICK: -- you went out there and you built the combustion turbines, then how far out -- I mean, you're going 15 years in these IRPs, but how far out are you making these assessments? What I'm hearing you say, as it relates to EnCompass, you're basically looking at early retirement of coal and not thinking about the debt that's out there already invested that might need to be securitized with the coal generating facilities, nor would you be looking at necessarily the cost that could be stranded assets from

combustion turbine units going in at some point at a future date?

MR. THOMAS: Yeah. That's -- I recognize that's the coal stranded assets that's going to be addressed in build impact analysis, but, you know, as I was talking a little bit before about stochastics, and it is possible that kind of using that uncertainty analysis you might -- you know, you might see that -- that it's likely that some of these combustion turbines that you're building over the next 10 years might be retired early. You know, whether or not EnCompass can actually include that in their optimization algorithm, I'm really not sure. I'd have to speak a little bit with them and better understand how the model can do that. But typically when a new unit is built in EnCompass, it extends out through its life. The model would not retire that early, and so that's not really going to be a factor in its expansion plan.

There might be a way to make all new units that are built be eligible for endogenous retirement. I'm not sure if that's a possibility. And Ms. Wilson may know more. I believe she's worked with the model extensively. But, you know, that's obviously going to add significant computational time, where you have a model that's, you

know, building new units and immediately second guessing the build of that unit. I mean, you're -- you know, you might take what normally would be a three-day model run and stretch it into a three-week model run.

So certainly, I think it might be possible, but I don't know enough about the intricacies of the model to say whether or not it can do that.

COMMISSIONER McKISSICK: And so I know little about the intricacies of the model except for what I've read and heard. I thought I would look to you for additional insights. But I'm understanding your -- your characterizations of capability, functionality, and the way it most likely would be utilized, so I thank you for your presentation and for your feedback.

MR. THOMAS: Sure.

COMMISSIONER CLODFELTER: Okay. Gentlemen, thank you. And Mr. Thomas, I hope you get a prize for all the heavy lifting you did doing this presentation. Mr. Metz and Mr. Hinton, you two look good in suits and ties. Thank you all. Ms. Edmondson, is there anything else?

MS. EDMONDSON: That is all on this issue.

COMMISSIONER CLODFELTER: Okay. Thank you. Mr. Burns, don't go away. We're at 4:00. If we run to

5:00, can we take care of Mr. Levitas or not?

MR. BURNS: That would be fine.

COMMISSIONER CLODFELTER: Okay. We can do it?

MR. BURNS: Yes, sir. I believe we can.

COMMISSIONER CLODFELTER: Okay.

MR. BURNS: Mr. Levitas is here and can speak up on that if he feels like it, but based on our conversations, if we could push to 5:00 and finish him and the other Intervenor witness by 5:00, I think we'd be in good shape.

COMMISSIONER CLODFELTER: All right, because I know he's got problems tomorrow and that's why --

MR. BURNS: Yes, sir.

COMMISSIONER CLODFELTER: -- I want to be sure we get him in. But first I'm going to have to give our court reporter our afternoon break. I'm not going to push her through the afternoon break, so --

MR. BURNS: Understandable.

COMMISSIONER CLODFELTER: -- Mr. Breitschwerdt, I think given where we are, and we've heard an awful lot today and we've got a good -- good grasp on this issue, I'm not sure we really need rebuttal on this issue, especially given the constraints we've got with our witness availability right now. I'm going to sort of

plow ahead.

MR. BREITSCHWERDT: Press on. Sounds good. Thank you, sir.

COMMISSIONER CLODFELTER: All right. Understood. I appreciate your accommodating all we're trying to manage here. Thank you for that.

We'll break and come back at 4:10, and we'll start with the second topic, and we'll start first with the Intervenor presentation on the second topic. 4:10.

MR. BURNS: Thank you.

(Recess taken from 3:58 p.m. to 4:10 p.m.)

COMMISSIONER CLODFELTER: Let's go ahead and get started. And Mr. Burns, since you've got the witness here, I'm going to turn it over to you, and we'll start on Topic Number 2.

MR. BURNS: Thank you, Commissioner Clodfelter. I'm John Burns representing Carolinas Clean Energy Business Association. Thanks to Gudrun Thompson and Nick Jimenez for adjusting on the fly. We are going to present Steve Levitas as the first witness on the issue of all-source procurement, then we understand that Commissioners will -- the Commissioners will ask questions of Mr. Levitas, and then Mr. Jimenez will take over with another witness on the issue of all-source

procurement.

CCEBA is happy to sponsor the testimony of Steve Levitas, who is a member of the board of directors of CCEBA and Senior VP of Regulatory and Government Affairs at Pine Gate Renewables. Most importantly, Mr. Levitas was the Co-Chair, along with Jack Jirak of Duke, of the Competitive Procurement Subcommittee of Governor Cooper's North Carolina Energy Regulatory Process, or NERP, and he is going to discuss issues related to all-source procurement in the current docket. Mr. Levitas, take it away.

MR. LEVITAS: Thank you, John. Good afternoon, Commissioner Clodfelter and members of the Commission. I appreciate the opportunity to participate in this technical conference and share some thoughts with you about all-source procurement on behalf of CCEBA, and I personally thank you for accommodating my schedule.

As you consider the role of all-source procurement in the utility planning process, there are four primary points I'd like to share with you on behalf of CCEBA.

First, we believe that all generation resources should be competitively procured. Second, we believe that resource procurement, to the extent not

legislatively prescribed otherwise, should be directly linked to and driven by the integrated resource planning process. Third, we believe that competitive procurement should be open to all resource types and generation providers that can meet the identified resource need. Fourth, we believe that any new all-source procurement process should be implemented in connection with Duke's next IRP cycle and that in the interim, absent new legislative direction, the Commission should require immediate large-scale procurement of renewable energy pursuant to G.S. 62-110.8. CCEBA would strongly oppose delay in additional competitive procurement -- competitive renewable procurement pending the implementation of a new all-source procurement process. We believe such delay would make it impossible to achieve Governor Cooper's decarbonization goals.

Beyond these four primary points, I'll share a few thoughts with you about the design of all-source procurement programs and how they are integrated into the planning process.

With respect to my first point, the benefits of competitive procurement are obvious and well understood. It drives cost down for ratepayers and spurs innovation. We have seen those benefits in Duke's implementation of

the CPRE program which has saved hundreds of millions of dollars for North Carolina ratepayers. CCEBA, as I said, believes that all generation resources should be competitively procured.

But assuming one agrees with that premise, how do we decide what resources should be procured? One of the primary goals of any integrated resource plan proceeding is to identify the current and future resource needs of a regulated utility. To understand the potential role of all-source procurement in the IRP process, one needs to start by considering the relationship between utility planning and procurement.

Under the traditional paradigm, which has been followed by the North Carolina utilities and this Commission in the past, planning and procurement are independent activities. Duke has described the IRP process as a continuous planning exercise that in any specific proceeding simply provides a “snapshot in time” of the utility’s resource needs.

Under this view, the IRP does not necessarily determine what resources will be procured by the utility and it certainly doesn’t directly drive the procurement process. Rather, when the utility decides that it has a need for a particular volume and type of new generation

resource, it typically files a petition for a certificate of public convenience and necessity to obtain permission to build, operate, and rate base that generation asset. In most cases one would expect the proposed resource to be consistent with the most recently approved IRP, but I don't understand that to be a requirement of law.

In approving a requested CPCN and making a finding that the proposed resource is reasonable and prudent, the Commission may well require the utility to demonstrate that the resource is cost effective relative to other alternatives, but that has not typically been done by requiring the utility to conduct a competitive solicitation in which multiple resources are able to compete to provide the identified resource need.

Among other problems with this approach, it doesn't lend itself to consideration of a portfolio of diverse resources, including, and this is of tremendous importance to CCEBA, ones owned and operated by parties other than the utility.

One way to link planning to procurement would be for the Commission to determine through the integrated resource planning process how much and what type of new generation should be procured. Under this approach, which is I think similar to what's occurring in South

Carolina, investor-owned utilities must meticulously and empirically evaluate resource needs and propose a specific preferred resource portfolio for the Commission to approve, modify, or reject. That approved resource plan would then presumably define the resources that the utility must competitively procure.

Alternatively, under all-source procurement, the IRP process does not initially produce such a prescriptive plan with respect to resource type. And let me just digress and say for a moment -- I think Duke points this out in their materials -- all-source procurement means many things to many people, and so there's not one exact definition of the term, so I'm going to describe it as I understand it, which is based heavily on the way it's been implemented in Colorado.

So in this approach, the preferred resource portfolio is developed through a three-step process. First, the Commission conducts a proceeding to consider the range of potential resource needs and a range of possible assumptions about key parameters, such as fuel cost, carbon pricing, capacity factors, stranded asset risks, and demand-side management penetration.

I want to especially underscore this point. All-source procurement does not eliminate the need for an

administrative proceeding in which many of the same issues that confront you in the IRP -- this IRP proceeding must be litigated. Once that step is completed, the utility conducts a competitive solicitation to secure firm pricing for various projects that may be selected for the preferred portfolio.

Finally, the utility proposes and the Commission approves a preferred portfolio based on the determination of what is most prudent and reasonable in light of the bid prices, the risk presented to ratepayers, and any other applicable policy goals. All-source procurement directly links the planning and procurement processes and ensures that the most cost-effective option for meeting the resource need is selected.

You'll note that there were two parts to my last sentence. The first was I said directly links the planning and procurement processes. That brings me to the second key CCEBA point. We strongly believe that absent express legislative direction to the contrary, all utility generation procurement should be directly driven by the planning process. In our view, the IRP should not be a paper exercise, but should lead directly to competitive procurement of generation resources. This

position is consistent with the recommendations of the NERP Competitive Procurement Subcommittee report, or the committee that Mr. Jirak and I co-chaired.

And let me just share two relevant excerpts from the subcommittee report which, by the way, I believe we provided as a supporting exhibit to my comments. Page 7 of the report, and this was a consensus position of diverse stakeholders, including Duke, “In the event that a specific capacity or energy need is identified in any IRP, such need should be filled through an all-source RFP that clearly defines the operational and other characteristics of the needed resource, absent any unique circumstance.” That’s the end of the quote.

As an aside, it’s important to note that the report referred not just to capacity needs, that is, where demand exceeds supply and new resources are needed for that basis, but also to energy needs, which is to say where there is a more -- potentially more cost-effective or less risky way to supply energy to customers over the planning period.

And then skipping to the next recommendation in our report which deals with the topic you’ve just finished covering, I’m quoting again, “If determined to be reasonable as part of an IRP, the Commission should

direct the utility to conduct one or more all-source RFPs to assess whether particular coal units can be retired in a cost-effective manner" -- skipping a parenthetical -- "through the procurement of replacement generation."

The second part of my earlier sentence was "ensuring that the most cost-effective option for meeting the resource need is the one selected." All-source procurement helps achieve this goal by opening the procurement process to generation providers other than the investor-owned utility.

As you know, in regulated generation markets, customers typically are made to bear the construction and operating risk associated with generation resources owned by the monopoly utility. It's the rare occasion when regulated utilities are not allowed to recover from ratepayers most of the impact of construction delays and cost overruns. In addition, regulated IOUs typically continue to recover generation plant cost regardless of their operating performance.

By contrast, where energy and capacity are provided by independent power producers such as our members, they're not -- they, not the ratepayers, bear all these risks. Specifically, IPPs get paid only for the energy they actually produce and deliver. If they

fail to deliver, they lose revenue. That's not true for IOUs.

Another important issue is what the ownership and cost recovery model is for any competitively procured resources. Under CPRE no procured renewable generation resources are rate based, which would mean that the utility would be allowed the full capital cost, recovery of the full capital cost of the resource, plus an approved rate of return recovered over the useful life of the asset.

Rather, there are two alternative forms of cost recovery. The first is for the utility to purchase power from an independent power producer, such as my company, pursuant to a contract for a term of years. The second is for the utility to act as a market participant that competes and recovers cost just like an IPP, that is, through defined production revenues for a defined period of time.

CCEBA believes CPRE has served ratepayers well and is an excellent approach to procurement and cost recovery. However, it's well known that Duke and other utilities would prefer to be able to own in rate base new renewable generation resources, and House Bill 951, as passed by the House, would modify CPRE to allow it to do

so. It remains to be seen what, if anything, on this issue will be enacted into law and whether the Legislature will assign any role to the Commission in deciding appropriate ownership splits, so I don't intend to say any anything about that issue here, but if such a statutory change is made, CCEBA believes that any resource to be rate based and resources to be rate based have to be separately -- should be separately procured from PPA resources. That's because it's difficult to compare the cost of utility-owned rate base assets whose full cost plus an authorized rate of return is recovered over the useful life of the asset, to independently owned assets that contract to sell energy capacity for a defined term that is shorter than the facility's full useful life.

In order to make such a comparison, a so-called terminal value must be attributed to the independently owned asset for the remainder of its useful life after the initial contract period. That presents several problems. As an initial matter, it's far from certain that the IPP will even seek to sell its output to the utility after the initial contract period, which as you know for CPRE has been 20 years. Market opportunities for IPPs in 20 years may be dramatically different from

what they are today. That aside, calculating the terminal value is highly speculative and a controversial proposition. As a result, the NERP subcommittee recommended that PPA resources and utility-owned resources be separately procured, not procured in competition with each other. As I mentioned, CCEBA supports this approach, and I believe Duke does as well.

There's also a compelling case to be made that is in other states such as Virginia, Michigan, and Colorado, any utility owned and rate based assets should be competitively procured through a build/own transfer model under which independent third parties convey assets to the utility at commercial operation potentially somewhere earlier in the cycle. In addition to the direct cost benefits of this approach, there very well may be -- tax benefits could be possible to convey at some later point in time and still realize those -- fully utilize the tax benefits.

Finally, let me offer a few thoughts with respect to the questions posed by the Commission in its Order scheduling this technical conference. I've already generally described how an all-source procurement process might work. As to who should be involved in creating and administering that process, CCEBA strongly favors a

process that is established and overseen by the Commission as part of the integrated resource planning process rather than one that is separately administered by the utility.

As with CPRE, there is a need to involve an independent administrator or independent evaluator in the procurement process, the latter, in our view, being acceptable if the utility and its affiliates are not competing against independent market participants.

CCEBA supports the Commission's adoption of rules governing all sorts of procurement, which could potentially allow such a process to be utilized in conjunction with Duke's 2022 IRP submittal. As stated above, CCEBA also believes it's essential that any such process not delay or otherwise interfere with additional renewables procurement under 62-110.8 subject, again, to any modification of that statute that may be made by legislation this session.

With regard to statutory authority and the need for new legislation on these subjects, another question you posed, I've not conducted a thorough review of Chapter 62 with this issue in mind, but I'd share the following preliminary opinions.

First, the Commission has very broad powers

under G.S. 62-30 to “supervise and control” public utilities as it deems necessary.

Second, as you know, G.S. 62-110.8, as currently written, already provides for the competitive procurement of renewable resources, with the Commission having the authority to determine what procurement should be required after this year. I don’t see any reason why the Commission, in exercising that authority, couldn’t require that the need and cost effectiveness of additional renewables be based on an all-source procurement process.

Next, I think the Commission clearly has the authority under current law to deny a CPCN application by a utility if the utility has not demonstrated the prudence of the proposed facility by showing that it has prevailed in an all-source competitive procurement process.

Finally, I believe that under current law the Commission can disallow recovery of the cost of the continued operation of existing fossil fuel plants unless the utility demonstrates through competitive procurement that there is not more -- are not more cost effective alternatives for ratepayers.

As with any form of all-source procurement

under any of these scenarios, the Commission would need to establish applicable assumptions with respect to the parameters I mentioned earlier, fuel cost, carbon pricing, capacity factors, and stranded asset risk.

In closing, let me commend to you the Rocky Mountain Institute's 2020 report entitled How To Build Clean Energy Portfolios, A Practical Guide to Mixed Generation Procurement Practices. I apologize that I didn't think to submit a copy in advance, but I'd be happy to do so after today.

The report contains a wealth of information about competitive procurements around the country and analysis of best practices, and emphasized three things that I've touched on in my comments, the benefits of linking planning and procurement, the need to design a system for the procurement of portfolios of resources, not just individual generation units, and the importance of considering not just short-term cost, but long-term risk to ratepayers, what RMI and others refer to as a least-regrets analysis. And I believe, Commissioner Clodfelter, you may already be familiar with this report since you received a thank you in the acknowledgement section.

I also want to say in closing that in order to

accommodate my schedule, I am preceding John Wilson, but I do want to say that CCEBA is very supportive of Mr. Wilson's views on these matters. He's a leading national expert on this subject. And I'm sorry that I wasn't able to follow him and have the benefit of hearing what he had to say first, but I think it's very likely that we would agree on most issues.

So thank you, again, for the opportunity to share these thoughts. I'd be happy to answer any questions.

COMMISSIONER CLODFELTER: Thank you, Mr. Levitas. Let's see. Are there questions from Commission Staff?

MR. McDOWELL: Commissioner Clodfelter, I do not have any questions.

COMMISSIONER CLODFELTER: All right. Thank you. We'll turn to the Commissioners. Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No questions for Mr. Levitas.

COMMISSIONER CLODFELTER: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions, but thank Mr. Levitas for his presentation.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: Just one question. And Mr. Levitas, you've explained this in your remarks, but I want you to do it again just for my benefit. Explain the linking -- explain how the all-source RFP would work in conjunction with the planning process, how do the two go together?

MR. LEVITAS: So as I mentioned, I favor the Colorado model, and that is -- it is a, by definition, integrated process of planning and procurement. And so in the first phase of the process, the Commission does two things. It considers generally what it's trying to solve for with respect to resource needs, which may be contingent on the prices that are obtained through the procurement process. So the Commission may say we think it might make sense to retire these coal plants, we're not exactly sure what pricing we'll get and whether we will actually save money for ratepayers, but we have enough reason to think that -- that the market would support the transition, so we're going to go out into the market and get pricing with the goal of procuring new resources and retiring old ones.

As I mentioned, the other thing that has to happen in that first phase of the proceeding is the

Commission, through a -- typically through a litigated process or settlement, would have to have some way of establishing the parameters or certain assumptions to be fed into the portfolio development. A particularly obvious example of that is what assumption is made about gas prices, because the procurement that you're going to do with respect to a gas plant is going to be for the capital cost. It's not going to be for firm gas pricing. So if you're comparing, say, gas to solar plus storage, you're going to need to know about the -- you're going to need to make an assumption about what it's going to cost you to run that gas plant. Similarly, with respect to the solar and the storage, you're going to have to make an assumption about its capacity factor and how much it operates in order to -- for those resources to be compared.

So all that happens in the first phase. Then the utility goes into the marketplace and conducts an RFP. It gets real bids back that are going to lead to real awards, assuming the Commission approves the plan, and then the utility in conjunction, what I mentioned, with an independent evaluator, would prepare a proposed portfolio that is based on a combination of the assumptions that the Commission has approved and the

market pricing that it's obtained through the competitive solicitation and then present that portfolio to the Commission for approval. And assuming the Commission approves it, the utility would enter into contracts with the parties that have been identified in the RFP, and it would contract to procure those resources.

CHAIR MITCHELL: So just to follow up there, from a timing perspective, though, I mean, you know, the IRP has been a long -- you know, it's a forward-looking process. We go out 15 years. So is the procurement that you're -- of which you speak, is it a long-term -- I mean, are we looking 15 years out? Are we solving for the most -- for the first need identified in Phase 1? Help me understand the timing.

MR. LEVITAS: That's a really good question, and I believe one of the earlier witnesses talked about this timing issue. And, obviously, the -- I think Mr. Snider testified that the new resources have to be procured on a schedule that would allow the existing resource to be retired, so that's the first thing. But I think more directly to your question, Chair Mitchell, the -- these procurements would occur in tranches or stages. So you may do a 15-year plan that gives you a long-term projection of what the likely needs are, but the actual

all-source procurement would be based on some definition of near-term needs.

So if you said, okay, what we're trying to take a look at is retiring Roxboro, and so we're going to look at a portfolio of resources to replace that plant by 2026 or some date, that's all you would be doing in that initial procurement. And you would have a series of procurements. It might be possible that there would be more than one round coming out of a single IRP proceeding if you're having biennial IRP proceedings, or it may be that the way to think about it is that every two years you're having a procurement that is driven by the most up-to-date IRP process. But you would not be committing at day one to procurement of all of the resources that were projected to be needed over a 15-year period.

CHAIR MITCHELL: Okay. That's helpful. Thank you for that.

COMMISSIONER CLODFELTER: Anything further?

CHAIR MITCHELL: (Shakes head negatively.)

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: So thank you, Mr. Levitas, for your presentation. I just had a follow-up question to Chair Mitchell's question. In this type of scenario where you would be doing it every two years, and

we heard Mr. Snider talk about, you know, a time frame that he thought that the need maybe in the '24/'25 time frame was going to be pushed out, how -- I mean, how has Colorado dealt with that, or has anyone dealt with that if you set up a procurement process and the need does not materialize?

MR. LEVITAS: I can't say that I have direct experience with that situation. I think, you know, if it is the case that Governor Cooper's decarbonization goals become the law of the state, it will not be possible to implement those goals without regular procurements occurring almost every year. And so we'll see, you know, what happens in the Legislature. I don't want to speculate about that. But -- and by the way, I should also mention there's federal legislation pending that could also be a driver for this.

So if there is any sort of external driver with respect to -- specifically with respect to decarbonization, that is going to create a new type of need, so the need is not just from, you know, does the supply meet the demand. It is we've got an established policy goal in the state, and we have to systematically go about implementing and achieving it.

COMMISSIONER DUFFLEY: Okay. Thank you. And

so that would -- that would go along with we're going to retire this certain coal unit at this certain time, and that's where you kind of see the -- this type of procurement requirement?

MR. LEVITAS: That's right.

COMMISSIONER DUFFLEY: Okay. Thank you for that. I don't have anything further.

COMMISSIONER CLODFELTER: Thank you. Commissioner Hughes?

COMMISSIONER HUGHES: Yes. I have a question about just transmission cost and interconnection cost. You know, I know how we're doing it with the CPRE, but just moving forward with your approach, who would bear the risk of transmission costs that, say, come in much higher than, you know, the original proposal? It seems like you could lock in -- I mean, you could lock in the generation cost, but then the transmission cost just seemed to be a moving target often.

MR. LEVITAS: Right. Well, I guess the first thing that I would say is that where you do have an external policy driver, particularly with respect to carbon, or for that matter if you had a need with respect to system reliability, if you have a firm need, that is, you've got to have new generation either because you've

got a plant that's got to be retired and you've got to replace it, or because you have an environmental policy goal that has to be achieved under state or federal law, then, you know, absent some off-ramp that says you don't have to do it under certain circumstances, then it's necessary to achieve the goal, and the objective is how do you achieve it in the least cost way and the least risky way, the least regrets way.

And you're absolutely right, Commissioner Hughes, that transmission costs are the unknown, the question mark. The cost of generation is continuing to go down. That's not the obstacle that we face in, you know, our energy future. It is transmission cost and upgrade cost.

You know, I think that what -- you know, what I would expect would happen is that if you have an identified portfolio and you have not -- and the transmission or upgrade cost, interconnection cost of that portfolio have not been fully studied and fully evaluated, that you may want to have that be a contingency. In other words, I mean, in an ideal world the decision about the portfolio would be made when those costs are fully known. And I'd need to think about it further, but I don't think that it's impossible to do

that.

I don't think in CPRE to date we've seen a lot of shift in transmission cost from the time awards were made until the time the contracts were signed. There's certainly the potential for that to occur, but I think the short answer to your question is in an ideal world the selection of the preferred portfolio would be made after the costs were known so you wouldn't have that risk of cost increases.

COMMISSIONER HUGHES: Okay. I appreciate that. No further questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: Thank you, Commissioner Clodfelter. Just one question. You've spoken of Colorado. How longstanding is this experience in Colorado, and what's the track record been like?

MR. LEVITAS: I believe Mr. Wilson can speak to that in detail, and it's certainly discussed in detail in the Rocky Mountain Institute report I mentioned. My recollection and my belief is that there was a -- they've been sort of working on implementing this for the better part of a decade, but the really successful detailed, fully flushed out version of this they may have only done

once. I think it started in 2016 and concluded around 2019, if I'm remembering correctly.

I can tell you that it was wildly successful. They had a huge number of bids. The pricing that came in was incredibly attractive and resulted in significant savings for ratepayers.

COMMISSIONER McKISSICK: Thank you. No further questions.

COMMISSIONER CLODFELTER: Mr. Levitas, I want to ask you one question that's really rolling around in my head, and so I want to get your help with how I should think about this.

You, in your presentation, urged the Commission not to delay continued rounds in the CPRE process under the existing statute after the end of a 45-month period, not to delay that waiting for a much larger all-source procurement, but continue to let that model continue to operate. And so this is the question that's rolling around in my head. The statute that authorizes the Commission to continue that program says we are to base that continuation upon the showing of need in the utility's most recent integrated resource plans. And so I look at the integrated resource plans on file and currently under consideration, and in the base case

without carbon, no new renewable resources are economically selected. All the additional renewable resources are legacy resources from PURPA or from the existing CPRE program or the South Carolina procurement program. So what's my basis of need if I'm going to say the base case is the reasonable planning case? What is the need if it is shown for another round of CPRE procurement?

MR. LEVITAS: Well, thank you for that question, Commissioner Clodfelter. The first thing I would say again is that this deck may get reshuffled by the Legislature, and we'll see where that lands, so we should be mindful of that. But in the absence of legislation, my response would be, well, first of all, that I do think that given how far along you are with this IRP process, that it would make sense to complete this IRP cycle for the purpose of making that decision. So that's the first thing. So -- and maybe that's what you envision. I'm not sure. The last IRP is several years old. You're well into a current IRP process. So that's the first thing I would say.

If you should decide to accept the base case scenario and then identify no need, then it may well be that you would not be inclined, maybe don't have the

authority to order additional renewables procurement, as I suggested. Implicit in my recommendation is, you know, the positions and testimony that you have received from us and others that the base case is not the appropriate scenario and that -- and as the South Carolina Commission has found is not the appropriate scenario and is reflected in Duke's resubmittal in South Carolina, so there -- my -- I don't want to get into litigating those issues, but there are certainly multiple pathways in front of you that could lead you to a different conclusion.

COMMISSIONER CLODFELTER: Thank you for that. I won't press you further on it. I just want you thinking about the same question that we're rolling around in our head. And to the extent you have thoughts to share, we are interested in hearing. Thank you.

That's all I have. And I believe, Mr. Burns, that's going to conclude with Mr. Levitas; am I correct?

MR. BURNS: Yes, sir.

COMMISSIONER CLODFELTER: Okay. I tell you what, given the hour, and we've -- the Chair has had to leave us already, so rather than start anything new, we'll break for the day. Thank everybody for a very efficient and well-organized day. I'm looking forward to

a repeat tomorrow. So we'll be back tomorrow morning at 9:30 a.m. And remind me again, who is to be up next?

MR. BURNS: It will be the SACE Intervenors with the witness that is Mr. Wilson, John Wilson.

COMMISSIONER CLODFELTER: Very good. 9:30 a.m. tomorrow. Check in in advance, make sure you have no technology problems, and we'll resume at 9:30. Take care.

(The technical conference was recessed, to be continued on October 1, 2021, at 9:30 a.m.)

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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 165 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 14th day of October, 2021.

Linda S. Garrett

Linda S. Garrett, CCR
Notary Public No. 19971700150