PLACE: Via Videoconference

DATE: Thursday, September 30, 2021

DOCKET NO.: E-100, Sub 165

TIME IN SESSION: 9:30 a.m. to 1:00 p.m.

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

IN THE MATTER OF:

Technical Conference

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

VOLUME: 1

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Duke:

Coal Retirements Panel:

Glen Snider   Michael Quinto
Dan Donochod   Robert McMurry

All Source Procurement Panel:

Glen Snider   George Brown
Jim Northrup   Bill Quaintance

Grid/Transmission Panel:

Glen Snider   Bill Quaintance
Sammy Roberts Nick Wintermantel
Mark Byrd

Southern Alliance for Clean Energy, Natural Resources Defense Council, the Sierra Club, Carolinas Clean Energy Business Association, and the North Carolina Sustainable Energy Association:

Rachel Wilson Jeremy Fisher
John Wilson   Steven Levitas
Jay Caspary

Attorney General's Office:

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P R O C E E D I N G S

COMMISSIONER CLODFELTER: All right. Good morning, everyone. Madam reporter, let's open the record and everyone, please come to order. I am Commissioner Dan Clodfelter, and I am presiding at this conference this morning.

Joining me via Webex are: Commission Chair Charlotte Mitchell, along with Commissioners Lyons Gray, Kim Duffley, Jeff Hughes, and Floyd McKissick, Jr., and Commissioner Brown-Bland will be joining us as soon as she is able.

This Technical Conference is being held in Docket No. E-100, Sub 165, which is titled In the Matter of 2020 Biennial Integrated Resource Plan Reports and Related 2020 Renewable Energy Portfolio Standard Compliance Plans -- that's a mouthful -- for Duke Energy Carolinas, Duke Energy Progress, and Virginia Electric Power Company, Doing Business As North Carolina's Dominion Energy, North Carolina.

Under General Statute 62-110.1(c), the Commission is to develop, publicize, and keep current an analysis of the long-range needs for electricity in North Carolina.

And in order to assist the Commission in that responsibility, the Commission conducts an annual review of the Integrated Resource Plans that are prepared by each of the three utilities I named earlier, those being the three largest utilities under the Commission's jurisdiction. Commissioner Brown-Bland, good morning, has now joined us.

On May the 1st of 2020, Dominion filed its 2020 Integrated Resource Plan. On September 1st of that year, Duke Energy Carolinas, Duke Energy Progress filed their Integrated Resource Plans.

Many, many parties have been allowed to intervene and to participate in this docket. The Commission has received comments and reply comments. And, in some cases, subsequent reply comments on the Integrated Resource Plans from the parties.

We have held six public witness hearings to receive evidence from over 200 public witnesses, and we received, in addition to that, several hundred written consumer statements of position from interested persons.

The written comments, reports, the analyses, the studies, the compilation in this docket run to several thousand pages.

The Commission has found all of these

submissions to be of very high quality. And, for that reason, on most of the issues that are raised, the Commission has concluded that no additional benefit would be derived from evidentiary hearings in the matter.

However, after considering all of the filings, the Commission identified three topics of interest, in Duke Energy Carolinas and Duke Energy Progress' Integrated Resource Plans, that we wanted to hear more about and hear you talk about in person, so that brings us to this morning's hearing.

On August 24th, this year, the Commission issued an order scheduling this conference to gather additional information about those three topics which were identified in the order, and they are:

And first, the methodology for evaluating the economic retirement of the Coal Fire Generating Units for Duke Energy Carolinas and Duke Energy Progress.

Second, the potential use of All Source or All Source Procurement processes by the utilities to secure their next identified needs.

And third, the grid impacts of the different resource portfolios that were presented for consideration in the two Integrated Resource Plans.

The scheduling order discussed the Commission's interest in these topics. And while the Commission had selected them for this conference, we identified, in that order, the parties who have presented comments on those three topics, and invited those parties to make presentations.

For purposes of the Technical Conference this morning, the presenters will be Duke Energy Carolinas and Duke Energy Progress that we'll collectively refer to sometimes as Duke.

They will also include the Public Staff, the North Carolina Attorney General's Office, and then, jointly, two groups of Intervenor parties: The North Carolina Sustainable Energy Association and The Carolinas Clean Energy Business Association that sometimes I'll call.

And then another group, jointly: The Southern Alliance for Clean Energy, the Sierra Club, the Natural Resources Defense Counsel. Sometimes I'll likely refer to them as the SACE parties, for shorthand.

As was provided in the order setting this conference, Duke will be allowed up to one hour for its presentations on each of the three identified issues.

The collective group of the Intervenor parties, the SACE parties, and NCSEA parties, I'll sometimes call them as a group the Intervenor parties, will be allowed up to one hour collectively for their presentations on each of the issues.

The Attorney General's Office and the Public Staff will each be allowed up to one-half hour for their presentations on each issue. And let me say I hope it's not a surprise and shouldn't bother you, but the order doesn't say so, but I will allow the Attorney General and the Public Staff to yield their time to one another, if they choose to do so.

If one of them wants to save more on one topic than the other, as long as we stay within that hour range for the two, I'm fine with that if you wanted to yield topic time between you.

In the case of the Intervenor parties where we've got a large number of presenters, I'm going to ask that at the beginning of your presentation, on each issue, you let me know how you've allocated the hour among you and sort of in the manner that's done when there are multiple parties on an appellate argument.

If you do that, it will help you. I'm not going to hold you to those allocation times, but it will at least allow me to call your attention, if you're beginning to run into time that you've wanted, to reserve from one of your colleagues on the same issue, and so that be would helpful if you can do that.

The time is yours this morning. You don't have to use it all, but I'm very sure you will use it wisely. Now, for the order, our sequence of presentations, we'll take the topics in the order I identified the topics.

On the first topic, we'll have presentations from Duke first, then followed by the Intervenor parties as a group. Then the Attorney General's office, and finally, the Public Staff.

On the second topic, which is the All Source Procurement -- and we're going to vary a little bit from the order to establish the conference.

We've decided it would probably be best if the Intervenor party, the NCSEA parties and the SACE parties, present first since they are the proponents and advocates for the All Source Procurement process.

That will allow them to flesh that process out and for us to explore any questions about how we might want to consider that. And then we'll take the Attorney General, the Public Staff after that, and Duke will back cleanup on that issue.

And then on the final topic, we'll go back to the order of presentation on the first issue. Duke first, and then the Intervenor parties, and then the Attorney General, then the Public Staff.

I went through that fairly quickly. I hope it's fairly all intuitive. I hope most of it is consistent with the understanding of the order. If you got any questions about the sequencing or the time, I'll be glad to hear you. If not, I'm going to roll on and you can --

MR. JIRAK: Commissioner Clodfelter --

COMMISSIONER CLODFELTER: Yes.

MR. JIRAK: -- this is Jack Jirak on behalf of Duke --

COMMISSIONER CLODFELTER: Yes, Jack.

MR. JIRAK: One very minor procedural issue I want to raise to your attention, make sure that you're okay with this. And given that this is a Technical Conference and not an evidentiary hearing, it's perhaps the case, the Commission already intended to treat presenter appearances more informally, but out of an abundance of caution, we wanted to address one of the issues.

One of our panelists, George Brown, who's going to be handling the All Source Procurement presentation, has a pressing personal matter to attend to that has arisen somewhat unexpectedly and at the last minute.

So Mr. Brown will still be able to present at the appropriate time, but with the Commission's lead, we would just ask that Mr. Brown be excused from the Technical Conference immediately after his presentation, and the Commissioner question, so that he can attend to his personal matters.

Again, that's perhaps the expectation, anyway, but I just wanted to confirm that will be okay with the Commission.

COMMISSIONER CLODFELTER: Mr. Jirak, you are correct, that is the expectation. This is not an evidentiary hearing. It's not an adjudicated proceeding, as we said in the order.

By the terms of the statute under which we're operating here, in this docket, and as confirmed by Appellate Court decisions, we're sitting more in a legislative capacity here in this proceeding than in an adjudicative or judicial capacity.

So, we won't be standing on the kind of protocol, we won't be swearing parties in. We won't be hearing witness summaries, thank goodness, and parties don't need to be formally excused. They can come and go as they wish.

If they're absent, well, you know, it's because they have something better to do, and that's fine. I understand. The goal of the Conference today is just to help the Commission gain a better understanding of these three topics and provide an opportunity to ask some questions deep in our understanding. So, as we've already indicated, there won't be any sworn testimony or cross-examination.

We are going to make -- as you've already noted, we are going to make a record, a written transcript of the Tech Conference so that the Commission's staff and the Commissioners can review anything that is asked or said, so please help the court reporter out this morning by speaking clearly and speaking directly into the microphone, as if you were testifying in a formal proceeding.

With that being said, let me -- I think this may be one of the first occasions. Let me introduce our court reporter to you this morning. Tonja Vines, raise your hand.

(Indicating)

COMMISSIONER CLODFELTER: She is the newest member of our court reporting team here at the Commission. We're glad to have her here with us, and I know she's going to be a valuable addition to our staff here at the Commission.

So, I want to thank all the parties for filing your presentation materials earlier in the week. This was very helpful. It afforded staff and the Commissioners an opportunity to better prepare for the session today.

I think I speak probably for all my colleagues in saying that the presentation materials are -- I consider them to be of very high quality, and that means I'm expecting an excellent session for all of us.

Finally, before I take appearances, one necessary reminder. I think everybody on this virtual session has become old hands at this process by now, so I'm not going to go through all of the ground rules about how we do these things remotely.

But, it seems that however many times we've done this routine over the last 18 months, that there's one point that still has to be brought up every time, and that is if you're not speaking, keep your microphone turned off so we don't get feedback or interference, and I would appreciate that as well as everyone else.

So, I think I need to do this, I think, under the State Government Ethics Act. It's prudent for me to remind all the Commissioners of our duty to avoid conflicts of interest.

And let me just ask, at this time, whether any Commissioner has a known conflict of interest or appearance of conflict with respect to the matters that we're going to be talking about this morning?

(No response)

COMMISSIONER CLODFELTER: Madam court reporter, nobody spoke up, and so let's have the record reflect that no Commissioner identified a conflict. And, likewise, I do not have any such conflict. So, are there any additional matters that we need to address?

MR. BURNS: Commissioner Clodfelter --

COMMISSIONER CLODFELTER: Yes.

MR. BURNS: -- this is John Burns representing --

COMMISSIONER CLODFELTER: Yes, Mr. Burns.

MR. BURNS: Good morning. Just a point of clarification, you changed the order of presentation on Topic 2. And just for clarification, did you intend that the Intervenors, particularly the NCSEA parties, would have the opportunity to do rebuttal since that order is reversed? Just for clarification. I'm not requesting that. I'm just wondering if that's what you thought.

COMMISSIONER CLODFELTER: As we said in the order, we may not have rebuttal from anybody on any issue.

MR. BURNS: Understood.

COMMISSIONER CLODFELTER: Again, this is not that kind of proceeding. And a lot of what we really need, as a Commission, is already in the file, in the record.

And, so, we're really not looking for a he-said-she-said, back and forth, trying to find who ran the stop sign this morning, so we may or may not have rebuttal at all.

MR. BURNS: That's fine. I was asking -- oh. I'm sorry. I was asking the question only because we're trying to time our witnesses. We have Mr. Levitas who would be -- has a doctor's appointment tomorrow morning, but your change of the schedule may make that irrelevant, at this point. He may fit in early, so we should be good.

COMMISSIONER CLODFELTER: Well, I'm hopeful. We've got all day tomorrow. We've got all day today, of course, and we've got all day tomorrow.

If we get through the first issue, as we expect we might, I think probably Mr. Levitas would be up some time this afternoon, and that should take care of him tomorrow morning.

MR. BURNS: Thank you very much.

COMMISSIONER CLODFELTER: Again, I'll go back to the original order of presentations, if you'd like. I thought Commission's staff had communicated with you about this thought, but --

MR. BURNS: No, it's actually very good, Commissioner. We appreciate that. Thank you for the change.

COMMISSIONER CLODFELTER: That's great. Okay. We'll take appearances now for the presenters, and we'll start with the two utilities.

I also understand, by the way, that Dominion, although Dominion, we didn't call you for a presentation this morning, I understand you're attending this morning, you may not be presenting, so, but, we'll start with the two utilities for their presenters.

As you introduce yourselves, please let me know who is going to be the lead counsel on each on topic. What I'll do when that topic comes up is I'll look to you as the MC on that topic for your presentations, and then you may coordinate your presenters respectively.

Before I take the appearances, though, let me acknowledge also that we had, as our order states, NC WARN and the Center for Biological Diversity had been invited to present this morning.

They have subsequently advised the Commission that they do not intend to present this morning, and so let me just make sure the record reflects that they were invited to present and have advised that they do not have presentations to make this morning.

So with that, we'll start with taking

appearances, beginning with Duke.

MR. JIRAK: Good morning.

COMMISSIONER CLODFELTER: Take it away.

MR. JIRAK: Thank you, Commissioner Clodfelter. Jack Jirak on behalf of Duke Energy Progress and Duke Energy Carolinas, and I'm joined by my co-counsel Brett Breitschwerdt with the law firm of McGuireWoods.

Mr. Breitschwerdt will be handling the first panel on coal retirements. I'll be handling the second, and then Brett will be up for the third as well, so thank you for this chance to present.

COMMISSIONER CLODFELTER: Very good. Thank you.

MS. KELLS: Commissioner Clodfelter, this is Andrea Kells with McGuireWoods, appearing on behalf of Dominion. As you noted, Dominion is not making a presentation. We're just appearing as a party to the proceeding. Thank you.

COMMISSIONER CLODFELTER: Thank you. Glad to have you with us this morning. Let me move to the Intervenor parties, and we'll start with the NCSEA group of parties first.

MR. SMITH: Good morning, Commissioners, Ben

Smith. I'm representing North Carolina Sustainable Energy Association or NCSEA.
I will be presenting and lead attorney for NCSEA and CCEBA on our witness or -- I'm sorry, our presenter Jay Caspary for Grid Strategies.

I also wanted to note that we are co-sponsoring witnesses with the SACE parties, and I would let Gudrun Thompson and Nick Jimenez from FCOC sort of present themselves and explain how that works, if that's okay.

COMMISSIONER CLODFELTER: That's fine.

MR. SMITH: Thank you.

COMMISSIONER CLODFELTER: Ms. Thompson, are you out there?

MS. THOMPSON: Yes. Good morning, Commissioner Clodfelter. Can you hear and see me?

COMMISSIONER CLODFELTER: I can now see you, yes. Thank you.

MS. THOMPSON: Gudrun Thompson, appearing on behalf of Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club collectively, the SACE parties; and with me is Nick Jimenez, also with the Southern Environmental Law Center, representing those same parties.

We will be presenting -- I will be, myself, presenting Rachel Wilson and Jeremy Fisher on the topic of coal retirements.

And as Mr. Smith mentioned, we are co-presenting those presenters together with Carolina's Clean Energy Business Association and NCSEA.

And, then, Mr. Jimenez will be presenting John D. Wilson on the topic of All Source Procurement, whenever we're up for that, on behalf of the SACE parties.

MR. CLODFELTER: Thank you. Mr. Jimenez, I see you, but your name does not show on your screen. And that reminds me that our court reporter has asked that -- again, she's new with us, and some of you have your names showing under your video, some of you do not.

So when you begin to speak, if you would, simply state your name for our court reporter's benefit. If you can get your name up on the screen under your picture, that would be even better, but some of you have the names, some of you do not.

So let me just remind you that when you start to speak throughout the next two days, if you can just state your name, for the court reporter's benefit, that would be a great benefit.

So, next, we'll turn to --

MR. BURNS: Commissioner Clodfelter --

COMMISSIONER CLODFELTER: Yes.

MR. BURNS: -- this is John Burns. I'm representing Carolinas Clean Energy Business Association, CC --

COMMISSIONER CLODFELTER: Yes, Mr. Burns.

MR. BURNS: I will be directing or presenting the testimony of Steve Levitas on Topic 2 which is the All Source Procurement topic, and we are also sharing or co-presenting the witnesses on Topic 1 and Topic 3, but I will not be the person presenting those witnesses.

COMMISSIONER CLODFELTER: Thank you, Mr. Burns, and thanks forgetting your name up under your photograph. Thank you. Next, the Attorney General's Office.

MS. FORCE: Good morning. My name is Margaret Force with the Attorney General's Office, and we will be presenting -- I will be presenting the 1st and 3rd topics. Mr. Edward Burgess is our witness and Maria Roumpani may be called on, depending on the questions from the Commission.

COMMISSIONER CLODFELTER: Thank you. Ms. Force, the volume -- your volume is a little low. You may want to turn your volume up just a bit.

MS. FORCE: Oh.

COMMISSIONER CLODFELTER: Now we've lost you all together.

MS. FORCE: Now can you hear me? This is my --

COMMISSIONER CLODFELTER: Much better.

MS. FORCE: This is my lacking in tech skills. I'm sorry. I failed to mention that Theresa Townsend is also going to be here, but I'm going to be the presenting attorney.

COMMISSIONER CLODFELTER: Great. Thank you. Good morning, Ms. Townsend too. Public Staff, Ms. Edmondson.

MS. EDMONDSON: Good morning. Lucy Edmondson with the Public Staff, on behalf of the Using and Consuming Public. Appearing with me will be Layla Cummings.

I will be the lead attorney on the three issues, unless the third issue runs long tomorrow. And then Ms. Cummings will have an appointment that I cannot change, so that's the plan.

COMMISSIONER CLODFELTER: We'll see if we can accommodate you. I'm sure everybody's going to be as efficient as they can. Anyone else who wishes to make an appearance that I haven't recognized already?

If not, then let me also say I neglected to say that what we will do after each presentation is -- and my apologies for neglecting this.

After each presentation, we'll have an opportunity for questions, and I'm going to give the Commission Staff an opportunity to ask questions first.

And if they have questions, we'll deal with those. And then after that, we'll take questions from the Commissioners.

As I indicated, we may or may not have rebuttal. That gets a little complicated, so we'll just sort of try to play that by ear as we go. If there's nothing else further, then.

Mr. Breitschwerdt, I think you're up. Duke is up on the first issue.

MR. BREITSCHWERDT: Thank you, Commissioner Clodfelter. Good morning, Commissioners. Again, this is Brett Breitschwerdt on behalf of the Duke

Companies.

The four panelists for the first presentation on Coal Retirements are: Glen Snider, Michael Quinto, Dan Donochod, and Bobby McMurry, and I'd ask them each to appear on screen and be ready to present now, if they could, please.

MR. SNIDER: Good morning, Commissioners.

COMMISSIONER CLODFELTER: Mr. Snider, we have you.

MR. QUINTO: Good morning, Commissioners. This is Mike Quinto.

COMMISSIONER CLODFELTER: We have you on screen too.

MR. DONOCHOD: Good morning, Commissioners. This is Dan Donochod.

COMMISSIONER CLODFELTER: Mr. Donochod, we have you.

MR. McMURRY: Good morning, Commissioners. This is Bobby McMurry.

COMMISSIONER CLODFELTER: Mr. McMurry, I think we have now all four of you. So, you-guys know how you want to do this song and dance, so take it away.

MR. BREITSCHWERDT: We do, and just a

logistical question because this is the first panel presentation. Mr. Snider's going to present, then Mr. Quinto. And then Mr. Donochod, and Mr. McMurry is going be here to support.

And Mr. Snider's going to go into some more detail, but is it more helpful for the Commission to have cameras turned off and only have one camera on?

My job is to control the slides this morning, so I don't think you need to see my face for very long, but for the four presenters, what's your preference?

COMMISSIONER CLODFELTER: Well, I think it's however -- different people will have their screens laid out differently.

Some will have a grid view, some will have only the speaker view, so it's really immaterial, I think. Different viewers will have their screens set up differently, so it really doesn't matter, Brett. However you want to proceed.

MR. BREITSCHWERDT: Okay. Well, thank you. And I guess just to kick it off, the Companies appreciate the opportunity to present this morning on this topic, which is an important topic that was addressed essentially in the proceeding.

And we developed, as you noted, a high quality presentation that we think hopefully further informs the Commission on this issue. So without further ado, I'm going to do my best to kick us off on the slide deck here. And Mr. Snider, if you're ready to take it away.

MR. SNIDER: Certainly.

MR. BREITSCHWERDT: At Slide 1, and just tell me when you want to move to the next slide, please.

MR. SNIDER: Very good. Well, thank you very much, Commissioners. I appreciate the opportunity to be with you this morning. This is an excellent forum.

These are complex topics, and the opportunity to bring our subject matter experts together is much appreciated, and we're happy to be with you this morning.

As Brett pointed out, we have a team here this morning and inclusive of Mike Quinto, who is a lead engineer on my team who helped to project manage the coal retirement analysis, because it was a very comprehensive project, involved multiple teams.

We have Dan Donochod with us here today. He is the general manager of our fleet transition. He and the engineers on his team are very active with our plants, you know, and help to develop the projections of costs under different scenarios for each of our operating plants.

We have our Director of Modeling, Bobby McMurry, to answer questions with us today. His team runs the Production Costs and System Optimizer models. He has a comprehensive team that was heavily involved in this.

You know, the people on this phone or on the conference today probably represent 100 years worth of experience in the utility industry.

Their teams are also full of very knowledgeable experts in analytics and engineering for multiple disciplines, and really looking at coal retirement analysis.

There's a multi-disciplinary approach that we took very seriously. We assembled a cross-functional team represented by the individuals on this panel today, as well as many members of their team and others throughout the organization, so we're happy to bring them together.

I present today, and to further answer any questions you may have. Brett, next slide please.

So just as a real quick level setting, what we'd like to do today is give you a brief background before we dive, you know, deep into the details. I'll start with just a high level, sort of level setting slide, and Mr. Quinto will get into some of the more detailed analytic questions that have been raised in this docket, and walk you through those.

There's both quantitative considerations that were raised in the docket as well as qualitative considerations. And we'll talk more about that later in the presentation, but Mr. Donochod and myself will talk about those qualitative considerations, and then I will finish up with where we're planning to go for 2022 as we move into our comprehensive IRP planning for next year.

So that's the order of our presentation today. I'd like to start by just maybe giving a little bit on just one slide -- Brett, next slide -- on the level setting of where we've been before we jump into what future retirements are, our plan for the system.

So coal assets in the Duke system, both DEC and DEP, have been a significant part of the energy landscape in North Carolina for decades, but that transition didn't start today.

I mean if you just look at this slide, and this is -- I pulled this from the executive summary of our IRP. Just 15 years ago, in 2005, 16, I guess, the State was served by predominantly two forms of energy, nuclear and coal.

And over the last 15 years, that transition has been pretty market, so many of our coal units have already been retired. We've retired 32 units totaling almost 4,000 megawatts to date.

We have, in addition to retiring, almost 4,000 megawatts, added 4,000 megawatts, approximately, of solar generation, as well as a significant number of efficient load following gas generators.

And, so, what this shows is, you know, this transition from 2005 to today has really resulted in a two-prong approach of adding more carbon-free renewables to the system, but also decarbonizing or reducing the carbon of your fossil fleet, so gas generators have only a fraction of the carbon output of coal generators.

And they're also more flexible and able to follow intermittent renewable generators, so that synergy has played out well for us over the last 15 years, and really has helped us to become a leader in carbon reduction.

So, 15 years ago, we emitted a thousand pounds of megawatt hour of carbon. Today, we're down to 600. That ranks us as one of the nation's leaders in low carbon intensity generation, serving North Carolina.

And, our IRP projects us, over the next 15-year planning horizon, to reduce that even further, consistent with our commitment to reducing carbon by at least 50 percent by 2030 and net zero by 2050. So, this is just a little bit of that two-prong landscape that's underway.

The discussion around carbon retirements really or coal retirements to further reduce carbon is really a progression of a transformation that's been happening now for a number of years.

And I think, really, when we get into it, the pace of that transition and the manner in which that transition happens will be, you know, actively debated, not only in this docket, but in future IRP dockets to come.

So, with that, I think I'll turn it over to

Mr. Quinto to walk us through some of the details, and then I will rejoin a little bit later in the presentation.

MR. QUINTO: Thanks, Glen. Once again, good morning, Commission. Thank you for the opportunity to appear in front of you today and help explain our process for coal retirements and how we look forward to 2022.

So, with that, I'll start with our regulatory technical background before getting into the specific modeling framework that the Company conducted, the 2020 core retirement analysis under. So this coal retirement analysis, per the North Carolina Utilities Commission order accepting the 2018 IRPs, as for analysis, removing the assumption that these coal units should be retired at their depreciable lives.

The modeling of these resources should be conducted under least cost principles to determine those retirement dates, and all appropriate costs should be included as denoted here with an example of coal combustion waste products.

Furthermore, per the scheduling of the Technical Conference order, the Commission understands the importance of this analysis, and the dates determined are foundational to the least cost portfolios that the Company presented in its IRPs.

The Company will, throughout this presentation, give the modeling framework and background necessary to help the Commission and Intervenors understand the detailed analysis that come before. Next slide, please.

So I will start by very high level describing a retirement analysis. So, fundamentally, a retirement analysis is looking for when to retire a unit and ultimately what to replace it with.

The decision to retire a unit needs to account for both the continued costs of maintaining that unit, along with the costs associated with retiring and replacing that unit if it were no longer there.

The existing capacity costs to the retiring units include costs such as Incremental CapEx, so the maintenance costs necessary to maintain the unit and maintain a reliable system over the long run.

It's associated fixed operations and maintenance costs. You may also have an environmental compliance cost, especially with carbon-emitting assets.

So if there are any emissions compliance costs that are required by certain dates, those are also -- should be factored into the equation.

And then, finally, you have a production cost of the system, so how does the system run, and what is the associated cost to run the system with that specific set of resources.

On the other side of this balance equation is the replacement capacity costs, and these include the new generation capacity costs to build or acquire these replacement resources.

You also have the new fixed operation maintenance costs related to these new resources. Transmission capital costs may also play a factor with both the retiring generation and the new generation, the appropriate transmission to reliably add that to the grid.

And then on this side as well, we have a production cost of the system where the new unit, whether existing capacity has been retired, and the new unit is now operating within the system as a whole.

So the equation is thus that if the -- I'm sorry, Brett. Can you please -- yes. The equation is thus if the cost of the replacements are more cost-effective than the existing capacity, then the unit should be retired.

The calculation quickly changes and gets more and more complex as when the unit is retired, and what it's replaced with, changes the balance of this equation, so we'll see on the following slides how this continues to make for a very complicated analysis that the Company undertook. Next slide, Brett.

So this slide sets up the scale of the analysis for the Company's IRPs. Along the left side are each of the units that are evaluated or in the Company's portfolio.

These units represent 10,000 megawatts of coal capacity, as Glen alluded to earlier. Each of the shaded boxes in the table represents a possible retirement date between -- the soonest it can be retired and the depreciable life of the unit.

And if you were to take all of the possible combinations and permutations of these retirements, that would be in the quadrillions or 10 raised to the 15th power, possible combinations of unit retirements.

So we can see that with our large fleet with a number of units in coal capacity, that just quickly becomes a tremendous scale.

And, finally, this 10,000 megawatts of coal capacity represents about 25 percent, a significant portion of the Company's combined firm winter planning capacity.

So being able to evaluate core retirements in a manageable, reasonable, and orderly fashion was key for completing this comprehensive retirement analysis. Next slide Brett.

So on the previous slide, when I referenced quadrillions of possible combinations of retirements, that is strictly looking at the -- when to retire each of these coal units. There's also the question of what, what to replace it with.

On top of this combination, The What further complicates the analysis, and I'll discuss how the Company used sound, economic framework to first capture the timing of that retirement, and then to determine holistically the best mix of resources to include in the portfolio over the time horizon, to best replace and fill that capacity and energy needs of the system.

So because of the complexity of this

analysis, it was necessary to create these logical steps that were meaningful in determining the economic retirement dates, and ultimately, what replaces them, those energy and capacity needs of the system. Next slide please.

So, as I discussed briefly on that last slide, the level of detail in determining these most economic coal retirement dates was crucially important. The precision, the accuracy of the costs, how the units operated, was all crucial to getting that retirement date directly.

The Company's process allowed us to use a detailed Production Cost Model and process that we're highlighting here on this slide as dynamic cost forecasting process to come up with those detailed costs to do that balance equation.

As we discussed, there's a significant component of the analysis is those costs associated with reliably maintaining the coal units while they're still in our portfolio.

The Company's detailed approach allowed us to optimally use the cost forecasting process, to use the most accurate representation of the necessary costs associated with operating and maintaining the coal units through the projected economic life, and we'll talk about how this dynamic process works on this slide.

So this process allows for accurately capturing the costs of these coal units, and here's just a list of some of the factors that can go into the changing costs of the units.

The utilization of the units actually can be taken into consideration and drive the investment and operation, and maintenance costs of the units over its life.

And as this utilization changes, these costs can be deferred, they can be reduced, and they can even be eliminated based on how the unit is used, and how long it is expected to operate.

This process, in a detailed manner, also allows for a realistic wind down of investments in our units, so as they approach a specified retirement date, they can dynamically change what's the expected cost to maintain that unit reliably through the life of the asset.

As I mentioned before, this tool also includes regulatory and environmental compliance required spend, so if they go past a certain date where a project is required for compliance, it would trigger having to incur that cost.

The tool and the process also allows us to redistribute costs to align to maintenance cycles for how costs would actually occur.

Furthermore, fuel operations influence the spend on necessary components. So if a unit is operating on coal versus operating on natural gas, and which blend, this process actually takes that into consideration on how much maintenance is required on the units, based on how the unit is operating.

And, finally, this process accounts for incremental coal combustion product costs, so not the cost that we're already going to incur.

But the incremental costs for any additional operation past today, that is factored in and considered in the costs captured in this tool.

So one way this can be thought of is an analogy with a car, right. So how long do we intend to keep this car may influence how we maintain and invest in the car over the long-term, so I'll run through a few examples.

So if we intend to keep this car for 15 years, we may be more likely to invest in tires that are rated for 80,000 miles or 100,000 miles rather than tires that are rated for just 40,000 miles.

Knowing that we're going to have this car for a long time, and to insure our reliability and cost-effectiveness over the long run, it makes sense to invest in those higher rated tires.

How we operate the car matters as well. One example here would be how we get to work every day. So for a highway commuter, we may not need to replace our brake pads quite as often as if we commute on city streets back when all of us traveled into the office.

I know that's not quite the case anymore, but the analogy holds up. So if you're commuting on the streets, you're constantly stopping at lights and making turns, and perhaps wearing down those brake pads faster, so how we operate the car matters in how we maintain the car as well.

And then depending on how much we plan to invest in this car can also influence how we maintain the car on a regular basis.

So for starting to cut down on improvements in the car, we may actually increase the maintenance costs over the short-term to maintain that reliability, to make sure we can get into work every day.

So if we're working with an oil change cycle of 5,000 miles, and we're starting to invest less and less in the car, we may decrease the time between oil changes every 3,000 miles, so that way, we are decreasing the investment in the car, but increasing the costs in the short-term to reliably maintain that car.

And finally, and this is an important one too. If we're a household of multiple cars, and we reduce down to just one car, it's going to change how much we use that car as a family. It's going to increase, you know, how often we run and how many trips we take, and then, thus, the necessary costs to maintain it over the long run.

So the methodology that the Company used allowed us to leverage this process and its ability to dynamically -- and based on detailed modeling -- really see how the units are operating, and when they're expected to retire to accurately reflect these costs with every potential retirement date moving out into the future.

So the graph on the right is just one

example of this tool. So this is two graphs representing the same unit with the same utilization; the top being a retirement in 2035 and the bottom being a retirement in 2031.

We can see that highlighted there with the red box. In 2028, in the first graph, there's a significant spend in 2028.

In this scenario, with the projection of 2035, it makes sense to continue to invest in the unit as it's projected to actually increase in use in this scenario.

We can see that in the bottom graph with the retirement of 2031. We still operate past that 2028 date, but we know longer have that same spend in that year, so what we're doing is winding down the cost projections that we're anticipating for that unit in that year.

So this is just one example of how this tool dynamically looks at operations and projected retirements to accurately reflect the costs of these units in such a critical component of the retirement analysis as a whole. Next slide, Brett.

So in the next section here, I will cover the methodology the Company used for the retirement analysis in the 2020 IRP and discuss the next steps for pursuing for the 2022 IRP. Next slide.

So in Integrated Resource Planning, there are two main tools used for retirement analysis. The first is a Capacity Expansion Model and the second is Production Cost Models.

Capacity Expansion Models are screening models used to identify possible portfolios based on thousands; and even more than that, options of portfolios.

And what these models are doing is seeking to determine when and what to add to the system to minimize the cost of the system. These tools, these models, these Capacity Expansion Models, are capable of doing retirement analysis.

And the resources as they are selected, they're based on simplified Production Cost calculations and capital for new and existing units using fixed input assumptions. So we'll talk about why that's important in the limitations of that in the following slides.

The Company used system optimizer for the 2021 IRP, so you may hear me reference our capacity expansion model or Bobby McMurry when he answers questions, may refer to it as system optimizers, so that is what we used for the 2020 IRP for our capacity expansion model.

The second model is a Production Cost Model. This simulates a detailed and chronological operation quantifying the performance of a specified portfolio of resources, so this is important.

So the capacity expansion model looks at thousands and thousands of innervations of different portfolio combinations and tries to minimize the cost of the system based on simplified calculations, and the Production Cost Model then takes a very detailed look on an hour-by-hour basis to determine how that single set of resources in its detailed production cost associated to serve customer's needs over the study horizon.

This type of model, this Production Cost Model, is also used to verify and refine capacity expansion results, so they're used quite often in tandem as a best practice in resource planning.

This model is also used to quantify the performance of a set of resources over a variety of input variables. Such is done in the 2020 IRP with the Company's scenario analysis where we have our six portfolios.

And they're tested over a range of fuel and carbon trajectories, carbon price trajectories to see how those perform, so there's multiple uses for each of these models.

The Company, in its 2020 IRP, used PROSYM, so the Production Cost Model will be sometimes referred to as PROSYM in this presentation.

So, importantly, the Company's retirement analysis leverages both of these models in combination consistent with sound resource planning principals to determine these most economic core retirement dates in their appropriate replacements. Next slide, please.

So as I mentioned on the previous slide, Capacity Expansion Models can be used to simultaneously solve when to retire these coal units and what to replace them with.

As mentioned earlier for the Companies, this is quite possibly quadrillions of possible retirement date combinations for these coal units, and then further layering on what to replace it with adds even more complexity very quickly.

So for these models to quickly evaluate these enumerable potential resource portfolio options, Capacity Expansion utilizes some simplified analytical approaches that aggregate an average hours and days and weeks and months into these representative hours.

Now, this is great for quickly evaluating many resource possibilities, but it does have some of its limitations, so this simplification results in the averaging of generation profiles such as with those with variable energy resources, such as wind and solar.

We also lose some of this inter-hour granularity in detail. So seeing exactly how a system would operate in any given hour with a specific set of resources, we lose some of that with this averaging and aggregating.

We also lose a bit of chronology. You know, to speed these models up, it removes chronology from a lot of these, so it's not an hour by hour So how this system operates from one hour to the next or one week from the next, which is important for how renewables and how batteries operate, and how the system responds to these, we lose some of that detail with these models.

And, finally, we lose the ability to dynamically forecast the cost of the existing units when determining that appropriate retirement date. These used fixed input assumptions that are static throughout the study period, so we don't get the opportunity to really evaluate how those changing operations, parameters, and retirement dates change the costs for the units in this retirement analysis.

The Company's retirement analysis, on the other hand, uses a well-defined systematic and multi-step approach that utilizes both Capacity Expansion modeling and Production Cost Modeling to optimize these retirements and the replacements in a very transparent manner.

So the Company's retirement analysis, breaking down this complexity into manageable steps, separating this What from The When into transparent and accurately optimizing the retirements, is just something a single model in isolation was determined not to be the most robust approach for such a complex question for the Companies. Next slide, please.

So this slide, we overview the multi-step approach and contrast it with the single-step analysis, so the Company's multi-step approach to retirement analysis consists of these steps seen on the slide.

I'll discuss each of them in a little more detail on the following the slides, but the ranking of units is done for the second step in determining The When. So to accurately evaluate the retirements in a detailed manner, the Company used its Production Costs Model.

And as we discussed, the Production Cost Model uses a specified set of resources. So to evaluate the retirements in a detailed manner, we needed to use the Production Cost Model; and, therefore, needed to rank the units so we could evaluate these specific set of resources in sequence.

The second step here is the sequential evaluation, the Sequential Peaker Method. It's the evaluation for retirement to find that most optimal retirement date.

The process acknowledges that the retirement of one unit impacts the operations of the remaining units in the fleet. So as we retire one unit, it may require the rest of the fleet to respond in a different way.

Looking at the units independently, we identified that this would inaccurately represent the incremental costs that each unit has to the system and further blur the lines of the true value to the system.

The sequential process allowed for the Company to utilize this detailed Production Cost Model in tandem with its Dynamic Cost Modeling of coal units to accurately evaluate the retirement dates from that equation that we looked at earlier in the presentation.

And then, finally, the Portfolio Optimization is done to determine The What. What are the replacement resources. So once we have established the retirement dates for each of the coal units, we're now finding the holistic set of resources that best fill those energy and capacity needs of the system.

The Optimization of the resources is actually performed in multiple steps itself, so it starts with identifying potential resources in the Capacity Expansion Model holistically, and then going to a verification and refinement of the results in Production Costs Modeling.

So these discrete steps that the Company undertook allowed for a detailed and, again, manageable and transparent analysis of the retirements, and a Single-Step Optimization through its simplified analytical approach seeks to do these two middle steps at the same time in a less detailed manner.

So the Company's approach to retirement analysis leverages this additional detail to more accurately determine the coal retirement dates, and then the replacements where the simplified model -- simplified Single-Step Optimization seeks to do this simultaneously with that analytical simplification. Next slide please.

So this table is shown also in the IRP in Chapter 11, Table 11-A. First, I'll start with "Due to the joint dispatch agreement of the transfer of non-firm energy between the utilities." The coal units were evaluated across the utilities.

The ranking process involved consideration of age of the units and its corresponding components; the cost-effectiveness utilization of these units, and then -- which is reflected here by the capacity factor ranges, and then the size of the units and how costs are efficiently spread over that capacity.

And, furthermore, the current system capacity length to retire units is also considered, as was the case for Allen Station, which we'll talk about on the next slide.

The capacity factors, represented here on this table, represent a range of single-year utilizations of units in the coal retirement group.

So this can be a little confusing from the slide, but generally, these capacity factors correspond to the value these units have to the system.

The older and the smaller units group together at the top of the list and evaluated first, tend to be less efficient. They utilize a technology called sub-critical coal, so that has to do with the efficiency process of how it converts the coal chemical energy to electrical energy.

Furthermore, the supercritical units, which are inherently more efficient, and also in DEC's case, are capable of co-firing with natural gas, which increase their flexibility, allow for a hedging of commodity prices and emitting less carbon, both by its efficiency and by the use of natural gas, are ranked higher in the left, so evaluate it later.

These larger units generally do have higher capacity factors based on those economies of scale compared to the system as a whole. And these larger units tend to be the most recently built, so they're -- and the most efficient and most utilized, and, therefore, the most valuable to the system.

The Company's choice of the core group rankings and the use of the Sequential Peaker Method doesn't necessarily mean the larger units with the higher capacity factors will retire later than the smaller units. Just that they're evaluated later.

So, finally, on this slide, the Company's rankings really seek to establish that reasonable order in which to evaluate these retirements in a sequential process considering age, the utilization, and the economics of size and scale of each of these coal group rankings. Next slide, please.

So this is the meat of the process of the coal retirement analysis. This is the Sequential Peaker Method determining The When. So depicted here is a high-level graphic of the step-by-step process, which I'll walk through now.

Each pass of the Sequential Peaker Method starts with the development of two hourly Production Cost Models: A Base Case where the unit with the coal units in this group are continued to operate through their depreciable lives.

And then second step here is a change case where the units are retired at the end of 2025 and replaced with the equivalent capacity of a peaking resource, so two sets of detailed Production Costs Models that really show how the unit would operate. And from those, we can determine the optimal retirement date.

This third step, and noted here as the Net CONE step, is where the Company actually calculated the retirement analysis equation that we looked at earlier in the presentation.
It calculates the total cost of the system, including the cost to maintain those coal units, and we'll just start with an example of it through '25, 2025.

The production costs also associated with that coal unit group operating through '25, the replacement capacity costs, operating from '25 through the original retirement date of the coal units, and then the cost to maintain those coal units.

Furthermore, the calculation also considers the new capacity costs and the necessary transmission, and if applicable, and any associated fixed costs with the new capacity as well.

So this total system cost calculation is then repeated for every year, on a year by year basis, from a retirement at the end of 2025 through a retirement at the end of the depreciable life.

So this year by year evaluation allows for us to transparently see exactly what the contributing costs are as determining the most economic point for retirement.

And, as previously discussed, the retirement date, the cost to operate these units are recalculated dynamically with that dynamic cost forecasting process used in the economic evaluation for each year.

So as we evaluate this each year throughout time, we recalculate what the cost will be associated with the retirement date that's specified.

In the next step, the Companies -- it's called Optimize here. The Companies identify the point in which the retirement of the unit minimizes the cost of the system, giving all of the detailed costs in this process, so it looks at every year from 2025 retirement through the end of the depreciable life, and you can kind of think of that as a line graph.

It may start high and dip low in the middle and begin to rise at the end. It may start out high and get lower as the unit gets to its depreciable life or it may start out low and get more expensive over time. And based on where the unit reaches its lowest point is how we determine the economic retirement date.

So in the final step, once we've identified the point at which the retirements minimizes the cost of the system, the Company locks that retirement in, and it becomes part of the new Base Case for the next coal unit group being evaluated in the sequential process.

In this sequential process, it's then repeated for every unit that was evaluated here. The table below shows the possible retirement dates evaluated by the Company for each of the coal unit groups from 2025 through the end of the depreciable life of each coal unit group.

You'll notice here that Allen was able to be retired earlier. This is based on the current capacity length of the DEC system currently has. The Company has accumulated capacity replacements over the past several years, including the addition of W.S. Lee combined cycle, the Bad Creek Pumped Storage hydro runner uprates, along with the future addition of Lincoln CT 17, which is expected to join the portfolio in 2024, which was a joint venture between Siemens and Duke to demonstrate the performance of advanced class CT's.

So while these coal units were evaluated sequentially, as I mentioned earlier, the economic retirement date for every group was evaluated between 2025 and the depreciable life. And we can see an example of this here as we look at Roxboro 1 & 2 compared to Roxboro 3 & 4.

Just because Roxboro 3 & 4 were evaluated later, didn't mean it was necessarily retired later. We can see here that Roxboro 3 & 4 was selected for optimal retirement in 2028, where Roxboro 1 & 2 were selected in 2029.

The table at the bottom, again, shows the order in which the units were evaluated and the table on the right shows the results in the order for which the retirements would occur.

So this economic evaluation framework determined in a transparent and detailed manner the retirements and when they should occur.

This economic framework is transparent, it's precise, and it's detailed in a way that optimizes those for each of the coal units. Next slide, please.

So, now, this is the Portfolio Optimization steps. So with the economic retirement dates now established in the previous step, the Company can take its holistic approach to the replacements needed to best fill these energy and capacity needs over the IRP time horizon.

The Capacity Expansion Model is first used to look over the long-time horizon at multiple resource options to determine the potential optimal combination of resources that minimizes the cost of the system to customers.

The results are verified and refined in Production Cost Models, including one example is the Company's process for battery optimization in the IRP where it, again, used the detailed, hourly Production Cost Model to capture the most accurate benefits to the system, so this is a very similar process to using that same level of detail that the Companies used in establishing its retirement dates.

So this step allows for optimal set of resources to be the replacement resources selected into the portfolio using a combination of that

Capacity Expansion Model and the Production Cost Model, and allows for a more accurate starting point when you begin to evaluate those on a detailed basis for refining and evaluating based on a narrower set and a more manageable scope in which to evaluate and confirm the resources and the timing. Next slide, please.

So the Company outlines here the relative strengths and limitations of each of the methodologies put forth in this docket, so this Sequential Method that the Company used is on the left, with the Single-Step Optimization or Endogenous Modeling on the right.

Strengths for the Sequential Method that the Company used includes dividing this large and complex analytical process into manageable and discrete steps.

The detailed modeling at each step of the analysis ensures that we have confidence in the results that we have. It allows for the use of more accurate and dynamic costing, and allows for transparency to see the step-by-step analysis and the critical factors leading to the retirement and replacement determinations.

Limitations of the Sequential Method is it requires significant resources to prepare and perform these analysis. You know, Glen did a great job of highlighting the cross-functional team that we brought together, with years of experience both in operations and strategy and planning, to really determine the correct process for capturing these most economic retirement dates.

With this analysis, you get fewer combinations and permutations to begin with, so it is a narrower set of runs that you're looking at. On the other side, the Single-Step Optimization or Endogenous Modeling of retirements, it has the ability to evaluate a large set of resource options to simultaneously determine the retirement dates and the needed capacity replacements, but the limitations include the utilization of this simplified analytical approach, loss of detail there.

It does not accommodate this dynamic cost forecasting that the Companies utilize that we -- I believe is the most accurate way of depicting continued investment and operations of these units, and then you get a bit of a lack of a transparency in the modeling outputs. It's sometimes hard to determine exactly why a unit was retired in a certain timeframe.

There's also computational constraints. So as we talked about, the high amount of combinations and permutations of just the retirements. On top of that, finding out what's the optimal replacement further makes up for further complicated computation. And to do that, you can actually stall out or have to relax the modeling tolerances to get it to evaluate it appropriately.

And then, furthermore, it's going to require this further modeling and verification, and confirmation and refinement of results. And you may, from this point, be starting from a less optimal set of resource selections based on the simplifications that were made.

So this very complicated process that the Companies undertook for the coal retirement analysis appropriately captures the economic retirement dates, and the Company is going to evaluate the new models and discuss with the Public Staff, as we'll talk about on the next slide.

So looking forward to 2022, the Company will use EnCompass as the model of record for the 2022 IRP. This EnCompass, by Anchor Power Solutions, has both

Capacity Expansion Modules and Production Cost Modules.

We have the same tools available to us in 2022. The Company's continuing to evaluate the enhancements and capabilities of EnCompass, so the new modeling software, and especially with respect to co-optimizing those retirements of the Company's coal fleet.

The Company plans to engage with the Public Staff and other stakeholders to discuss these enhanced techniques for evaluating coal retirements for these future IRPs, 2022 and on, and the Company will update, as it always does, its IRP assumptions.

And then for '22, actually complete a new comprehensive, economic coal retirement analysis, taking into consideration the input from the Public Staff and other pertinent stakeholders in these matters.

So the relative strengths of these multi-step process that the Company undertook outweigh the loss of detail that we saw from the Single-Step Optimization.

And while we think it's better and appropriate and an accurate depiction of the economic retirement dates, the Company's plan to work forward, continuing to evaluate the best tools that are available to us; the leverage, the information, and techniques that other stakeholders have, and conducting a new retirement analysis to further refine these results in 2022, are an important step going forward. Next slide, please.

So I think I've talked enough. With that, I will pass the presentation back to Dan Donochod who will begin our conversation and discussion on qualitative factors for coal retirement analysis, starting with the current head winds for coal plan operations. Dan.

MR. DONOCHOD: Thanks Mike, and good morning, Commissioners. My name is Dan Donochod, and I will share some of the headwinds for coal plan operations.

First, we support growing renewables on our system. As we know, SolarBites' nature is intermittent. And when cloud cover comes, the remaining system must perform a steep acceleration otherwise known as ramping of dispatchable generation to make up the lost energy.

While we have increased the flexibility of the coal units, they cannot accelerate or ramp generation near as fast as Combustion Turbines and combined cycles can.

Coal units were originally designed as base load units, and frequent cycling increases wear and tear on the unit. Since coal units have changed duties, it can be difficult to accurately predict how often they will run, and therefore, how much coal will be needed.

On the coal supply chain considerations, as the demand for coal declines, some of our suppliers have experienced financial hardships. In the past few years, nine of our suppliers experienced some form of financial restructuring.

Fortunately, we're able to work with them to ensure most of our coal deliveries were still made. Coal has also become a smaller portion of the railroad's volumes as our coal volumes decreased.

In 2020, coal deliveries were only 10 percent of Norfolk Southern's revenues, down from 26 percent in 2012. Another qualitative risk is the future environmental regulations.

Currently, EPA is working on tightening existing regulations that impact coal units such as

Effluent Limitation Guidelines or ELG, MATS, etc, and they also signaled their intent to issue new carbon regulations under the Clean Air Act. There will be new regulations also not yet drafted.

And, finally, we have the operational challenges we faced in running the coal units. We have expressed hour by hour desire to retire coal units early in an orderly fashion, but until the day that they do retire, we will need to maintain them to meet their mission and to provide capacity whenever needed by the system.

We are having difficulty retaining work force as coal employees are responding to the announcements about early retirement and planning for their futures.

Externally, as more coal plants retire, the industry has faced a wave of retirements and a loss of key talent and knowledge. For example, there are fewer skilled trade workers available on the open market place. And over the longer term, O&Ms may no longer be able to support us with spare parts.

So in summary, we manage through these challenges every day, but these are issues that the models cannot capture. So with that, I'll pass it back to Glen Snider for other qualitative matters.

MR. SNIDER: Thank you, Dan. Thank you, Mike. Again, just building a little bit on what Dan was talking about there. And Mike, no matter how comprehensive of a quantitative perspective, there's always going to be certain qualitative factors that are difficult to put into a modeling framework.

And, so, we undertook, as Mike described, a very comprehensive, robust, transparent, quantitative framework, but the record had a lot of qualitative considerations in it as well outside of the actual modeling framework. And, so, Brett, if you would advance the slides, please.

So we heard a lot about some of the qualitative risk of replacing coal with natural gas, whether they be simple cycle turbines or more efficient larger combined cycle plants.

Predominantly, the possibility of a shorter useful life, sometimes referred to by Intervenors as stranded costs risk, the potential risk of future carbon emissions, commodity price, volatility.

And then, you know, the future, they're our potential to mitigate through hydrogen burning at these plants, or if they're only being utilized for very limited amount of times, potential offset markets.

But those are uncertain this early in the development of those potential mitigants, but the record really focused on just that resource. And if you replace with other resources, all resources have volatative (sic) risk considerations, so I shouldn't just start it with BESS, so Battery Energy Storage Systems, are emerging.

And we think they're going to play a role in the Carolinas, but it is an emerging technology at utilities scale, and they have their own qualitative risk factors that need to be balanced along with qualitative risk factors of natural gas.

So, certainly, no single chemistry, at any scale, has been in operation for say 15 or 20 years. Well, you know, existing technologies do have, you know, well beyond 20 years of operation life.

So life cycle costs, the potential to have to run for a shorter life due to that lack of operation history is certainly a risk that exists with battery energy storage.

You know, you have global supply chain risk. We're seeing that across many items in society today, but batteries are dependent on a pretty global supply chain to produce these at scale, the level of scale being talked about if it was across the whole U.S. Really, there's no way to predict how the supply chain will adapt, and if it will adapt in a timely manner.

And then, finally, batteries even have their own environmental risk that are yet fully capable of being quantified in sort of a quantitative manner when you think about everything from the production - development of the battery, the installation, the operation of it, the decommissioning and recycling - because you don't have that long-term, the exact costs to move through that, and the environmental risk there need to be considered as just a qualitative factor.

Again, not that any of these are showstoppers, but they're certainly existent and in the market place but just don't get a lot of discussion in this particular docket.

When you move on to even, you know, sort of more emergent technologies like offshore wind in the Carolinas or in the southeast or small modular nuclear reactors, they also have qualitative considerations that have to do with some of the same issues with batteries but have even a longer lead time and more complex sighting.

So all technologies have qualitative risk. I think sometimes in a docket, we tend to focus on one, and so the note on the bottom there just says I think it's important to really have a fair and holistic consideration of qualitative risk factors when those are being considered in addition to the robust quantitative analytics that Mike outlined earlier in the presentation. Next slide please, Brett.

What the IRP shows, and what we really highlight is one of the best ways to protect against some of the qualitative risk factors, is to maintain a diverse resource portfolio.

So when you think about transforming the grid and transforming our generation fleet, what investments are being called for over the planning horizon from the IRP, and how diverse are those sets of investments to the extent, you know, all investment types, as we just spoke about, have some amount of qualitative risk.

And if you look at, you know, sort of going along with my introduction slide from 2005 to '21, now we're looking at 2021 to 2035. And what the bottom bar shows is of all the resources added, what percent of new resource additions are comprised of what types of resources.

So in the IRP, so what you'll see is there is the addition of a significant amount of renewables, in addition to some combined cycle technology on the left and the light blue, simple cycle in the dark blue.

The small amount of nuclear is simply nuclear uprates that we think are going to be achievable, so that's not new nuclear. That's really uprating the existing nuclear. We are putting a significant effort into DSM and EE, which is the light pink one, and then some of our pump storage, as Mike spoke about earlier.

We're uprating our existing pump storage, which is a great addition to the fleet to help follow the renewables, so it's really this diversity that really is in line with what we've been doing historically.

You're adding renewables. You're decarbonizing by going to a lower carbon, either through energy storage or through CTs and CCs to help follow those renewables that allows you to stay on that trajectory of reducing your carbon intensity per megawatt hour, well minimizing both quantitative and qualitative risk for consumers. Next slide please, Brett.

So as Mike spoke about, you know, moving into the '22 comprehensive, it's not just the coal retirement study. Obviously, there's a lot of input that go into a comprehensive IRP that help to inform the IRP as well as the coal retirement study, things like the reserve margin study, our effective load carrying capability study, our transmission studies, and we expect in the comprehensive IRP to be updating all of those supporting studies that are all interrelated to the coal retirement decisions in both, in terms of the timing of the retirement as well as the resources available to replace it.

Certainly, developments in state and federal policy play into this. Extension of tax credits, carbon policy, clean energy policy, all change the relative costs of these net costs to consumers, and so any change in policy would also be incorporated in our '22 IRP.

The third goal really talks about our commitment to energy efficiency and Demand-Side

Management and other distributed energy resources. We start with that. These resources are given the first opportunity to reduce our growth and our system, so we have a growing system.

We have tens of thousands of customers coming to the Carolinas. New businesses, new industry and energy efficiency Demand-Side Management and other distributed resources reduces that rate of growth fairly substantially.

We have a very comprehensive process to ensure we're trying to get all cost-effective energy efficiency. The issue I put this on the slide for is some of the record would suggest that you could use this to retire, further retire coal units.

What we've seen is that while this is very effective in reducing load growth, the magnitude of those Demand-Side resources are not on the same scale or with the same certainty that -- relative to the 10,000 megawatts of coal we're trying to retire, although they play a very important role in reducing growth on our system.

Again, I think what we'll try to do, endeavor to do, with stakeholders and the Public Staff going into '22, is have a more robust discussion around some of these qualitative benefits and risks of staying in coal, and what are the costs and benefits of moving faster than the most economic retirement date, and what might that look like, and get a broad discussion around those costs and benefits.

And, certainly, you know, the coal retirement says, as pointed out in the order, will be a significant driver of need in the '22 IRP. We have needs driven by load growth.

We have needs driven by expiring contracts. We have needs by retirement of other smaller gas or hydro units, things likes that, but a large function of the need in the IRP is the coal retirement, so we'll have continued focus on this and continued refinement, and we're committed to the level of resources that we've had in 2020 as we move into 2022. Next slide, please.

So maybe just some closing comments. I think Mike did a great job of explaining what the IRP did in terms of determining what types of resources are out there to replace retiring coal.

Despite maybe what some of the portrayals of hour by hour process was, in no way did we assume that a Peaker was the only thing that can replace a coal plant, so we just use the Peaker to determine The When.

The Peaker method is well-established. It's the benchmark for the Utility Cost Test. It's the benchmark for avoided cost rates. It's the benchmark in PJM, for the cost of the new entrance coming into PJM, and so that's a pretty well-established economic framework to help us hone in on The When to retire.

Then we ask what should retire it through the Endogenous Model, and we allow the model to select The Optimal What, so in no way did we restrict the selection of replacement resources to Peakers.

And so the IRP really does a good job of determining what types of resources are there to replace, when they should be replaced, and importantly, you know, as I spoke about in the reliability study, what amount of resources are needed to replace this coal, and so all of that leads to a very robust, comprehensive transparent.

We think it was done with a high degree of accuracy that you lose. We'll hear about other approaches done throughout the country. And in reviewing those approaches, well they may use a single step.

They have to take many more simplified evaluation techniques. They limit the number of years that are considered. Importantly, they cannot include the Dynamic Costing, that the tremendous effort we went through to develop the Dynamic Costing Model.

That cannot be accommodated in a single step, and so we think our approach really for the commissioning determining The What replaces it, The When, and The Amount, is just and reasonable for planning purposes as we see the 2020 IRP, recognizing that we'll refine it going into 2022.

And just a small nod to the upcoming sessions, while the IRP does a very good job of establishing The What's going to replace The When, and The Size, it's really the final Execution Phase after the IRP that identifies the precise, you know, how are we going to replace this.

You know, we're going to talk about the competitive procurement process, and what, ultimately. That'll be the resource, the location of the resource, and the specific resource that will replace coal will only be known at the Execution Phase.

And, so, you know, how that CPCN and RFP process is conducted, and how those resources are selected, that's when you'll know the precise What and the precise Where.

So, you know, I look at this whole process as we move through these three days or two days and three topics, and I thought they were done in a very thoughtful order as this winnowing approach, right.

So you start off screening models in the IRP, and then you go to detailed models, and you get a detailed set of resources, and then you move on to the Execution Phase where those resources ultimately become known, and the location becomes known, and the analytics become even more refined.

So there's this refining that happens in the beginning of an IRP process throughout it, and then finally, at the Execution Phase.

You'll know exactly what resourcing, where, and more detailed transmission and resource types will be known at that, and we'll hear much more about that in the coming two days.

But with that, I'd like to just say that, you know, the Company has taken its obligation to perform a detailed retirement analysis very seriously. As you can see from the panelists today, again, it was not just these panelists.

It was several members of each of their teams, my team and Dan's and Bobby's team that put just countless hours into looking at this, analyzing it, reviewing results, quality assurance of it.

We've made the Dynamic Costing Model available and transparent through data request. We've tried to be as transparent as possible, and so we just -- we're very supportive of our approach.

We think it's industry best practice, although it was -- this comprehensive nature does take a significant effort that maybe all companies don't have the time and resources to put into it.

So with that, I will conclude this formal part of the presentation and ask the Commissioners if they have any questions and just thank the Commission for this opportunity once again.

COMMISSIONER CLODFELTER: Thank you to all the presenters on the topic that was very thorough and very clear. Let's see. We're at 11:00. Let's see if we can take questions and get through all the questions on the Duke presentation, and then we'll take our morning break.

We won't start -- we won't take a break in the middle of a presentation, so let's go to questions now. And as I indicated earlier, I'm going to see if Commission staff members want to ask any questions of our panel.

Mr. McDowell, Ms. Jones, the floor is yours. However you wish to proceed.

MR. McDOWELL: Commissioner Clodfelter, this is Steve. I do have a number of questions I'd like to ask of the panel.

COMMISSIONER CLODFELTER: Sir, if you want to start now.

MR. McDOWELL: I won't direct any of these questions to a specific member of the panel, but anyone that can respond to them.

As somewhat of an introduction of myself, I'm in Operations Staff for the Commission. I'll refer back to Mr. Quinto's chart where he was showing the service lives of some of these coal plants and specific, Mayo. I think he was kind of alluding to the fact that these are old plants.

And I will say that when Mayo was being constructed, I started working at Carolina Power and Light Company, so I don't know if there's a direct correlation there or not.

The first question I have is do you know right now that the EnCompass software, when fully implemented, can be leveraged to better optimize coal retirement dates and replacement options, and I'm really talking about just the capabilities and functionality of the tool at this point.

MR. SNIDER: I'm going to let Steve take a shot. And then Bobby McMurry on our team, who is transitioning, who runs the modeling department, I'm going to ask him to follow up.

MR. McDOWELL: Okay.

MR. SNIDER: So EnCompass, as Mr. Quinto pointed out, still has two modules: A System Optimization Module and a Detailed Production Cost Module. And it's our belief their System Optimization Model does have enhancements over System Optimizer which is the current tool used in 2020.

At the end of the day, it is still a screening model in that it has to take -- it still does the same thing. It runs thousands upon thousands, and that number depends on how you specify the model.

So if you want to let it look at every unit, every replacement option, as Mr. Quinto pointed out, you get in the quadrillions, and it simply won't solve.

We've looked across the country. And as the portfolios become more complex, others that you'll hear about, Pacific Corp., etc., they use an endogenous model, but they make many, many simplifying assumptions going into the model to allow it to solve, and so we think we may be able to use EnCompass in a more expansive role.

We'll certainly see what its capabilities are, benchmark them, you know, against our current practice. And we expect it to yield benefits, but I still don't believe that any single system optimizer model can be used in isolation to get the most robust result.

That's just not -- given the lack of detail and the simplifications that have to be made, if you don't perform some of the analytics of it, that Mr. Quinto spoke about on both the front and the back end of that, it simply is not going to be sufficient as a single model to be able to do in one model step.

So long-winded answer, Steve, but Bobby, I don't know if you have anything to add to that.

MR. McMURRY: I mean, about the only thing I would add is I certainly agree with Glen's explanation, is that rather we use EnCompass in '22, it'll be a two-step process.

Even if retirement is selected with EnCompass, especially in the short-term frame, we're always going to look at it on an hourly production cost standpoint to recognize what its value would be.

And, also, I think it was on Slide 10 of Mike Quinto's presentation. You know, it really showed that the accounting for the reduction and as O&M decreases, as you hit a retirement date, that's just not captured within EnCompass or System Optimizer. That's a part of the Sequential Peaker Method.

So, certainly, we're testing it now. We're using EnCompass. I think it's a good model. As I've stated to Glen before, I mean, I like the ability of EnCompass in selecting -- you know, when you're having to evaluate 10 different carbon policies, you know, directionally, is coal retirement's, you know, accelerated or is it deferred to a later date.

I mean, I think it's a good tool for directional purposes, but when you look at really nailing down a retirement date, we're always going to look at it in both models.

MR. McDOWELL: Okay. Thank you. So you have a level of confidence based on what you've seen other players in the country do. But, basically, you're committed to attempting to utilize that model in the fashion that you described today then. So there's a level of confidence there, otherwise, you wouldn't commit the resources to that.

MR. McMURRY: I mean, I can point out a couple things with EnCompass that we're seeing that's a benefit over System Optimizer. It does allow for accounting for commitment of your units, where System Optimizer didn't.

In other words, when I say commitment, it's really about making sure there's enough reserves to meet your FERC and FERC requirements, VACAR requirements. That's something that S.O. didn't really allow us to do, so that's one advantage, but I still will stand by.

It is a screening model, and it'll still be a two-step process, even if we're allowed to -- you know, even if it's -- a retirement is selected at a different -- than a production cost, Sequential Peaker Method.

MR. McDOWELL: Okay. Thank you for that.

Commissioner Clodfelter, I had additional questions, if we're good.

COMMISSIONER CLODFELTER: You're done. You've got the floor until you're done.

MR. McDOWELL: Okay. I should have warned you how many questions I had. The timing of decisions on coal retirement dates affects all sorts of costs downstream of today's date. I think Mr. Quinto was very clear with that.

You may, for example, avoid some major maintenance capital in the short-term if the retirement date is solid, and you've evaluated the risk. I use the word solid or emphasize the word solid. Am I on track here?

MR. SNIDER: Yes, Steve. I think I understand what you're saying, and that's precisely why we've used this approach, right, which we've -- just to be very clear, a single-step approach does not allow one unit to have multiple cost trajectories that are a function of the retirement date, right?

And so what we're saying is the multi-step approach we took was -- it was very intensive to develop those multiple cost forecasts, and it does allow you to say if I retire early, how can I wind down the unit in a reasonable manner that changes my cost forecast for that same unit.

And so we -- once that comes into focus, I think when you said when it's clear, you know, once these retirements dates have been committed to and they become closer term, then we will spend, you know, according to that, you know, ramp down of the unit, you know.

And, so, I think it is, you know, a benefit of looking at that function of retirement, the cost forecast as a function of retirement age.

Just something that we're not seeing other people have gone to that level of effort to do. They put a single set of costs.

And if the model retires it, you avoid costs after that date, but it doesn't dynamically change your entire forecast with each year of retirement you're looking at, and we think that's a huge enhancement that some of the examples held up by Intervenors of other parties, that they have not taken that big of a step.

MR. McDOWELL: So in other words, you've reduced some of the capital spend for these units, as you've identified, earlier retirement dates, and that reduced spending's reflected in the present value of revenue requirements that you calculated that are reduced out of the IRP. Is that correct?

MR. SNIDER: That is correct.

MR. McDOWELL: Okay.

MR. SNIDER: Not just spends after, but spends in front of the retirement.

MR. McDOWELL: Right. Okay. So decisions about major maintenance capital or just some of the decisions that have to be made and are affected by known and actionable retirement dates -- I threw in a new word there, actionable retirement date.

Maybe the better word is firm because I guess you don't take action to quit spending on a unit or to do this or that or not buy coal for the unit until it's firm.

So let's talk about the concept of optimizing the coal retirement dates a little more. Duke stated in its reply comments that the Companies believe, given the capabilities of the current models, the approach used in the 2020 IRP yielded the most economic retirement dates.

So excuse me, but I want to quote from the movie "Hidden Figures", which everyone should watch. I know you probably believe that. What I'm interested in, however, is the additional value that might accrue to ratepayers if the EnCompass model is fully leveraged to identify coal retirement dates as opposed to the current methodology. Do you think there is additional value to be gained by leveraging the new EnCompass tools?

You've already spoken to somewhat the functionality and capability of the tools. I'm really broadening that a little bit to value to stakeholders, especially to ratepayers.

Do you think there's additional value to be gained by leveraging the new EnCompass tools to do the retirement analysis and other components of the IRP?

MR. SNIDER: So I don't want to be -- yes, the EnCompass model has -- to the extent as Mr. McMurry explained, we believe it's a better model. It will yield value in helping us ensure the results are evaluated using the best industry tools.

The big important nuance for the Commission to understand is using that model stand-alone or any model stand-alone without a multi-step approach that brings the problem into focus using a series of sequential, more detailed analysis and trying to do it in -- you know, I went and looked up a couple of different definitions because we hear a lot about endogenous, you know, it's an endogenous model, which to me, the way I read some of the intervening comments is just let the model decide everything.

Put everything in -- not in this winnowing approach, not go into ever-more detail, and doing, you know, detailed dynamic cost and doing detailed production cost. Just put it in S.O., EnCompass, PLEXOS.

You can name on one hand the number of models that are up on the industry to do that. And I think trying to do it all in a single model, whether it's EnCompass or any other model, would not yield -- that would not benefit consumers. It would lead to a less optimal result.

So EnCompass is good, but it's good in a framework. And EnCompass stand-alone or any model stand-alone done purely endogenously, meaning let the model -- let a single model drop the answer, is not a -- really the best approach.

MR. McDOWELL: Okay. Thank you for that. Let's go back to stranded cost for a minute that, Glen, I think you mentioned earlier.

As I understand the Public Staff's comments, they are sensitive to the issue of potential stranded costs if a suboptimal solution to carbon emissions reductions were implemented.

Partly, this discussion has to do with the uncertainties of carbon policy itself, which you've already alluded to.

Specifically, the Public Staff commented that this gives rise to an argument that existing coal generation plants should continue to run for a period of time, thus deferring the need for new natural gas plants while carbon policy uncertainty is resolved.

Can you comment on that observation and the observation that Public Staff made in its comments that the cost of carbon is the primary driver of differences between plants, and thus has to be considered when choosing plants?

MR. SNIDER: Carbon is one driver. Let me start by --

MR. McDOWELL: The Public Staff commented that it's the primary driver, so...

MR. SNIDER: That is not -- yeah. The primary driver -- what we ran -- we looked at things both from a carbon and no carbon, and the date does not change appreciably at all.

The type of resource, obviously, is influence, but the primary driver is the capital, and the operating costs, and the fuel costs, and carbon does, in fact, that running cost, so it is not the primary economic driver. It is an economic driver.

And, you know, we could say wait. It's interesting. We can say wait until carbon policy -- which, you know, I would love to have firm carbon policy, but I think I was told in 2009, as we were looking at one of the plants, that within two weeks, we're going to know what carbon policy is, you know.

We are -- Waxman-Markey is going to lay out, you know, carbon policy for us, and we sit here a decade later with no carbon policy, and so I think it's a critical question and why I laid out, you know, our historic actions of adding renewables at an aggressive pace while adding gas to follow those renewables and replacing coal.

Do we want to hit pause on that strategy that's brought us from a thousand pounds of megawatt hour by hour down to 600 pounds on a track to

300 pounds? That industry-leading pace that we're on, do we want to hit pause on while we wait for policy, and I think that's a question.

You know, one of those qualitative considerations that we're certainly -- I'm not going to solve in this Technical Conference, but would be one that we need to wrestle with in stakeholder groups, and this Commission needs to wrestle with is.

You know, do we hit pause on that and wait for policy or do you systematically work through retirements and replace them with the best available technologies that exist at that point in time that can meet that need that the retirement creates, and that's simply something we're going to have to continue to address in future IRPs.

MR. McDOWELL: Yeah. I think you've hit on a million dollar question that this Commission has to struggle with some, and that's whether it hits pause button or what, and so it's a good point. And I may have been the one in 2009 that told you Waxman-Markey was going to cure all, so I apologize for that.

Let's change gears just a little bit. Suppose that the Commission waited until additional analysis were available in the 2022 IRP docket before rendering a decision on the proposed coal retirement dates.

This might suggest an order in the second quarter of 2023 if we waited -- if the Commission waited for that. What would be the implications on the current short-term action plans?

MR. SNIDER: So, you know, you think about the IRP, you know, and that's why I said we think our retirements dates are just and reasonable for planning purposes today.

And the IRP, not just the short-term action plan, is used in all sorts of dockets, right? You look to it in rate cases, you look to it in avoided costs, and you look to it for need dockets when we come forward for need, and so I think -- you know, it is reasonable to say let's have another cycle through and look at what those needs are coming out of '22.

But, you know, the result will be -- and we'll get into this, I'm sure, in the All Source Procurement and some of the transmission even, potentially, is you generally have -- I'm going to use a really rough number, so don't hold me to it, but about a five-year lead time to bring replacement resources into focus.

And so to bring them on-line, full when you think about going through the RFP process, the CPCN process, the Permitting process, the Construction process, the COD.

So to move something to, let's say, '23 would, you know, in essence say you're looking at '27, '28 for those replacements, and these are very, very high-level -- you know, subject to Lot's caveat, so -- but that's just, you know, a rough ballpark for maybe how to think about that.

MR. McDOWELL: So that kind of goes beyond this very short-term action plan into the longer range plans and replacement of the capacity you're having to replace as say Cliffside 5 or Roxboro, Mayo, which we've already identified as old, is retired.

And it's clearly noted in your IRPs that -- and let me read here because this is well-stated. "The retirement dates discussed in this chapter do not represent commitments to retire. The IRP is a planning docket, but the execution of the plan can vary for multiple reasons, including changes to the load forecast, market conditions, and generated performance, just to name a few, similar to new undesignated resources identified in this document that do not have an approval to build or a commitment to build. The coal retirement dates presented herein only represent the current economic retirement dates and are not a commitment to retire," end quote.

So what you started doing was probing somewhat the question that I have, both from short-term but, you know, also the longer term implication.

Again, if the Commission waited until additional analysis were available in the 2022 IRP docket before rendering a decision on the proposed retirement dates, what would be the implications to the retirement dates of coal units currently targeted for retirements?

For instance, Cliffside 5 in 2026 or Roxboro, Mayo, units between 2028 and '29, are there critical decision dates this approach would put in jeopardy? Can you identify something on that to put some color to this?

MR. SNIDER: Certainly, Steve. I appreciate that question, and it is true. And, you know, to build upon that quote from the IRP, what's really critical for the Commission to understand is we need to have reliable replacement generation prior to retiring further units, right?

So when you talk about -- I'm just going to use, for example, Roxboro and Mayo at DEP. We cannot -- when we say it's not a commitment to retire, another variable that affects that is our ability to secure a reliable replacement that provides the equivalent system reliability to the unit that's being retired.

So whether -- you know, the first step in that might be the -- you know, the date is agreed to by the Commission, you enter into an RFP process as part -- and I don't want to go too far down that because I'm sure it'll come up in the next Technical Conference, but you enter into an RFP process as part of obtaining a CPCN for whatever resource, you know, and then you have to successfully conclude that and come up with a replacement, equally reliable replacement. And then once that equally reliable replacement is secured, you can commit to the retirement.

And so that is the order in which things have to happen, and so the Commission, agreeing with the dates, allows that first step to happen, to say we agree that there is a need, utility you now can move forward with, you know, the RFP process to help fill that need.

And, so, you know, I think we're getting to that point where the Commission is not pushing us beyond -- you know, you have a bit of an issue with Cliffside 5, maybe the one hanging out there, but all the other fleet, right, is at or beyond a date where waiting till '22 would allot -- would still -- we would have to move quickly, but would still allow time to execute coal retirement, you know, the RFP process, and, again, from a very high-level perspective, you know, subject to really digging into the analytics.

MR. McDOWELL: So we take a lead on that in what you say in the short-term action plans, especially for something like Cliffside 5 if there's a 2026 date, which isn't a firm date for you.

I mean your management team had said yes, by golly, we're going to retire Cliffside 5 in 2026, go ahead and get the process starting to replace that capacity, is that a true statement?

MR. SNIDER: Yes, it is not a firm date for Cliffside. Allen is committed to and we have plans in place for Allen. Cliffside is not yet official.

MR. McDOWELL: So I'm very much a believer in not making decisions today that I can make tomorrow. I have more input, more information from which to make that decision. If I don't have to make that decision today, I'd rather make it tomorrow.

In your mind or in any of your colleagues' minds here, would a delayed decision on coal retirement dates create additional opportunities for ratepayers or cause them to forfeit opportunities?

MR. SNIDER: That's the -- you know, as you've alluded to the million dollar question, right, we're talking about do we hit pause -- you know --

MR. McDOWELL: Right.

MR. SNIDER: -- do we delay one year, do we delay two years? You know, the Company's position, I believe, is that getting out of coal as expeditiously as possible, while maintaining system reliability and affordability, shields customers for some bit of qualitative risk that Mr. Donochod, you know, started to -- you know, he did a very nice job, but that's a lot to cover in a short amount of time, but you don't want -- let me say it this way. You don't want to be last man standing in the coal industry.

And we think transitioning out of coal in an orderly but expeditious manner where we maintain that reliability and affordability is the best approach.

So I agree with you that more information is better, as long as more information doesn't turn into well, we're going to have even more information in '24 than we had in '22 and, you know, it can become a slippery slope.

Like I said, I've been waiting on carbon policies, been imminent a half a dozen times in the last decade, and I was sure I was going to have something more definitive to put into my planning process, and that has yet to come to fruition, so...

MR. McDOWELL: And I've already apologized for that, but part of making the decision now or as you have information starts to address a number of things as technology's involved and costs, change.

Carbon is clearer, start to deal more effectively with this idea of stranded costs, obviously, so I'm not going any further with that, but thanks for that response.

I'm thinking ahead to our third issue a little bit and the timing of transmission planning outputs in relation to the generation resource planning. One question.

Does the transmission planning have much of an influence on the coal retirement methodology and dates?

MR. SNIDER: I would say the transmission planning has a partial influence in terms of the needed transmission to -- if you don't replace on site, and you remove the coal and replace with a different, then you need to have the -- two things have to happen.

You have to fix the grid because the grid is built around those coal units, so removing the coal units creates a need for incremental transmission investment, and then the replacement resources are likely going to need transmission infrastructure built to be able to move those new resources to the load.

And, so, to the extent they become the long lead time with respect to the construction and in-service date of that replacement resource, it can affect the retirement date.

MR. McDOWELL: Okay. Yeah, because as I think ahead, I'm thinking about which comes first, the chicken or the egg here, and I'm very confused by that a little bit, but that's an issue downstream.

MR. SNIDER: Well, we will hit on the

chicken or the egg I think a little bit in that third panel.

MR. McDOWELL: Right. One final question. Thank you for your patience. Based on DEP's 2020 IRP, there is a capacity need identified to support the forecasted 2015/'16 winter peak demand. That need's partly driven by the potential retirement of the Weatherspoon CTs. That's 232 megawatts of CTs down at that site.

Do you have a timeline of the steps necessary for DEP to provide for the forecasted peak load? Again, starting 2015/'16 winter peak. Do you have a timeline of the steps, which obviously, you know, could include what happens with these Weatherspoon CTs, but providing for that.

MR. SNIDER: It's a good question, and I think you were referring to '25/'26.

MR. McDOWELL: Yes, I'm sorry. Did I say '15?

MR. SNIDER: That's all right.

MR. McDOWELL: My notes said '15/'16, which is obviously not correct.

MR. SNIDER: So I think what we're going to be -- you know, there's a couple of factors that we will take a very hard look at for '22. One is updating the load forecast, you know, coming out of Covid.

What is the load forecast, the 2020 IRP versus 2022. Does that still support that '25/'26 need. Are there other things happening with uprates or other things that can help to defer that need.

And then, finally, taking a hard look at those units themselves and saying is that still the appropriate for these smaller turbines, you know, what's their material conditions and are they -- you know, is that the appropriate retirement.

So all of that, we'll take a really hard look at going into '22 and see if that need is still in that year. It's too early to tell but, you know, my --

MR. McDOWELL: So let me follow up to that. When I look at that winter peak in 2026, you've got an undesignated Combustion Turbine that's added, and like 2025, and you've got Weatherspoon taken out. So you've just talked to the forecast and whether or not it's appropriate to take those units out because that's not a done deal either.

The reserve margin would drop below your 17 percent threshold, actually. My calculation says it would drop 15.7 percent. If you wait until the 2022 IRP and you've got to replace capacity there or built new capacity or secure new capacity, does that give you enough time to do that if the forecast stayed the same and you committed to retiring the Weatherspoon units, et cetera? That's why I'm probing the time on it a little bit.

MR. SNIDER: It's a fair question. And I think, you know, if we didn't see, you know, preliminary indicators that we thought it was going to move, the need would move out.

So, for example, if we didn't go through Covid but we went through an economic, you know, explosion, and we had a bunch of industry moving in, and we saw that Weatherspoon was having serious material condition issues, we probably would have been -- we would have been more concerned.

I think our early read going into '22 is that need may be moving out, and so the immediacy of moving towards an RFP to fill that need, we're not seeing the early indication saying we need to be immediately moving towards an RFP to seek to fill that, fill that need.

And that'll be fully confirmed and discussed in '22 but, you know, I think, you know, you snap this chalk line with these IRPs, and I think that's a very important concept, right.

And you'll hear it throughout these presentations is, you know, these formal dockets, you have to use the best information at the time you're developing your information, your analysis, your filing.

But the world continues to move in between these two-year comprehensive IRPs, and so you've got to be reading the market, what's happening, and adjusting your business decisions, certainly consistent with your IRPs, but also understanding what's happening in between these chalk lines that you snap.

And I think what we're seeing in between the chalk lines gives us some indication that we think we're going to have time to meet that need through an orderly process that will be laid out more fully in '22.

MR. McDOWELL: Okay. I appreciate it. Commissioner Clodfelter, that's all the questions I have.

COMMISSIONER CLODFELTER: That's great. Mr. McDowell, do you know if any other staff have questions? Ms. Jones, I don't see you on --

MR. McDOWELL: Yeah, I do not. I don't think Ms. Jones has any questions, so that's probably sufficient.

COMMISSIONER CLODFELTER: All right. Let me tell you what I'm going to do here. We've been going for about two hours, and I want to give Ms. Vines a break. So let's talk our morning break here, and then we'll come back with Commissioners' questions.

Let's come back at 11:45, and we'll pick up then. All right? First call. If you stop your video and you go on mute while we're on break, please. Thank you.

(Whereupon, a break was taken)

COMMISSIONER CLODFELTER: Okay. I think we're all back. Let me tell you what I propose to do, and that's just to take Commissioners in order of seniority. We've been talking about old plants, so we'll start with the old Commissioner first, Commissioner Brown-Bland. You're up.

COMMISSIONER BROWN-BLAND: Well, despite the adjective, which I won't comment on further, I don't have any questions right now.

COMMISSIONER CLODFELTER: Okay. Commissioner Gray.

COMMISSIONER GRAY: Well, as much as I'm in overtime, I have no questions.

COMMISSIONER CLODFELTER: All right. Next in seniority, I think it's Chair Mitchell.

CHAIR MITCHELL: All right, Commissioner Clodfelter. Okay. I have a few questions for y'all. Mr. Snider, I'm just going to aim them at you and anyone can answer them, really.

In your opening remarks, you indicated that 15 years ago, Duke was at about 1,000 pounds per megawatt hour C02 emissions, and that has been reduced to 600 per megawatt hour. Is that in the Carolinas or is that Big Duke or --

MR. SNIDER: That's just the Carolinas, Chair Mitchell.

CHAIR MITCHELL: Okay. Perfect. Thank you. Another question that I have for you, and this is just sort of a general question. And to the extent you have already explained this, just forgive me. I've got to hear it again.

The focus on intra-hour hour by hour

variability and the need to be more granular, and examining the intra-hour variability, we've been hearing a lot about that lately, but help me understand. When did that become important or perhaps critical to the Company? Just kind of give me some context there, if you can.

MR. SNIDER: Certainly. It is -- you know, if you'll excuse my hand gestures, but this funneling, right, so our Portfolio Optimization Models don't even have hour by hour granulary.

They just use representative day types, right, so they're not even running the system on a true 8760. That's the number of hours in a year, every hour by hour of the year. They're very screening in nature because they have to run so many permutations.

Then the Production Cost Models, they're further down in the funnel. They look at every hour by hour but they do not look intra-hour by hour So they're not looking at the 5-minute, 10-minute, 15-minute pertubations that can happen in load, which is commonly what you'll -- where that comes into play is the amount of what are often referred to as ancillary services regulation balancing reserves that are needed further down in the funnel to follow that intra-hour variability.

Where we've done some of that modeling uses yet a more detailed model to look at that variability, still caustic model, but it generally doesn't look over a 15-year horizon because as you add the detail, you have to narrow the problems set, right, and so as you move down in that funnel where we talk about the intra-hour needs is largely in the avoided cost docket.

And some of the work on the solar immigration service charge, and it starts to relate the addiction of more intermittent resources, increasing the need for intra-hour load following, and so that amount of ancillary resources that are needed, you know, really plays into -- it's just, you know, an input into the IRP model, but it's not analyzed in detail the way it is in the avoided cost SISC, and so it really became more of an issue as that intra-hour volativity started to increase, and then making sure you've's got the resources to file that intra-hour.

CHAIR MITCHELL: Okay. That makes sense, Mr. Snider. And so then I assume, but you tell me if I'm wrong here, that as we move forward, it's going to -- you-all are going to have to continue to focus on intra-hour variability, maybe even increasingly so, and will your -- what point are your modeling capabilities going to get you where you can look at intra-hour variability or load pertubations I think is what you said, but then also do that across your planning horizon?

MR. SNIDER: You know, that's a great question. I think it's taking -- and this is why, you know, I think you raise a very good point on why one model can't solve all issues in a single model, and so what we look to do is we take the results of the detailed model, the very detailed model and say how do I then extrapolate those results.

How do I appropriately move the results from the more detailed model into the broader modeling framework, and so for example in the detailed model, as we look at tranches, if you will, of incremental, intermittent resources and we examine effect on intra-hour load, we can then say okay, when we do resource planning now, we start to understand that relationship, so we say in my resource planning models, if I'm going to have one scenario that has really high intermittent resources, and I'm comparing it to another one that doesn't have as much intermittent resources, I can use the results of my detailed model and say okay in this portfolio I need more ancillary services, in this model, in this portfolio, I need less, and it's the output of one becomes the input to the other.

CHAIR MITCHELL: All right. Thank you for that explanation. There were several slides that were presented while you were speaking. And there was a slide -- we don't have the slides up in front of us you now but may remember this. There was a slide with a pie chart that showed the Companies, sort of that transformation and resource portfolio.

MR. SNIDER: Capacity, yes.

CHAIR MITCHELL: And so I think there was just a question I had was the older of the two pie charts showed two, you know, sort of sections attributed to renewables. Is that a mistake or was that purposeful? I think it was on page 22, 21 or 22 of the deck, if you're looking at it right.

MR. SNIDER: Oh, yeah. If Mr. Breitschwerdt -- I don't know if can pull that up for us. I'll try explain and that slide a little bit. So what that slide is, and maybe it wasn't as clear as we could have made it, the two pie charts are installed capacity, sort of today, and at the end of the planning horizon, and then the bottom of the pie chart represents the difference.

So it's saying how much increment -- as I move from the first chart on the left to the pie chart on the right, what's the composition of the resources that are being -- so your never -- I always make this point.

We're never in any planning horizon replacing all the resources in the portfolio. We're making incremental advancements in the resources that are added to meet load growth and retirements, and so the bar chart on the bottom represent the makeup of those incremental changes between 2021 and 2035.

So of all the investments made, in, you know, what percent of the megawatts are in renewables, what percent's DSM, what percent's in storage, nuclear CT and CC, whereas the two top circles represent the systems as a whole, so one's a difference and the tops ones are.

So I think when we're saying seeing renewables at the bottom, that's the incremental renewables being added, whereas the renewables on top are total renewables on the system as a percent of installed megawatts.

CHAIR MITCHELL: Okay. Let me stop you right there. That's helpful. I appreciate you walking me through that. I think I see what's happened there. That may be Brett's mouse, but right there, sort of the renewables at 1.4 percent and then you've got renewables at 9 percent on 2021?

MR. QUINTO: Chair Mitchell, if I may. The renewables that's in pink in the 2021 pie chart, that's a mislabel.

CHAIR MITCHELL: Okay.

MR. QUINTO: That should be a portion of that is EE and DSM that makes up our winner capacity.

CHAIR MITCHELL: Okay.

MR. QUINTO: So that's just simply a typo, and we apologize.

CHAIR MITCHELL: That's what I figured now, especially after Mr. Snider's explanation. Okay. Thank you both for that help there. And then one or both of y'all help me understand -- and, again, it may be you go from 1.7 to 6. I think that's what you're doing. It's hard to see, for me to see the percentage of energy storage, but there is obviously an increase from 21 to 35.

MR. SNIDER: Right. And so that's a -- and you'll see in the bottom a little small print, and I apologize. It's a lot to put on a single slide, but that's both battery storage and incremental pump storage.

And so the incremental pump storage are the uprates occurring at our Bad Creek facility where we have approximately 240 potentially more megawatts being added at Bad Creek, in addition to incremental energy storage that we project coming out in the system.

CHAIR MITCHELL: Okay.

MR. QUINTO: I will add on this slide the amount of megawatts is vastly different between 2021 and 2035 due to the amount of additional renewables on this system. So as you get more name plate capacity or more winter capacity in 2035, that begins to shrink the portions.

A good example of that is you see 2021, nuclear's about 20 percent of our capacity mix. And then in '35, it drops down to just 16 percent. Well, we're not actually retiring any nuclear in that timeframe.

We actually have a small amount of uprates to nuclear, but because the amount of renewables on the system and name plate capacity overall, it makes those portions a little bit smaller.

CHAIR MITCHELL: Okay. And that's helpful clarification too. Thank you, Mr. Quinto. All right. A question about DSM EE. Mr. Snider, you indicated -- you were talking about, sort of, the limitations of DSM and EE at this point in time. And, you know, in the context of replacement, using DSM to replace units that y'all are going to retire.

And I understand the points that you were making. At what point in time, though, will, you know will we be able to mitigate or even, possibly, eliminate uncertainty associated with DSM?

You know, at what point will you all be able to rely on technology so that you're not having to rely on a customer to voluntarily participate or agree to take some action to meet your systems' needs?

I mean, are you all -- can you help me to sort of -- to the extent that you can look into your crystal ball and help me understand how far away we are, I would appreciate it.

MR. SNIDER: No, I think -- it's a really good question, and it gets interpreted different, depending on your lens. From -- in many stakeholder groups I've been in, that type of question gets open for interpretation.

So there are customer programs that are dependent upon customer actions, and we're going to continue to pursue those, right? So those are existing EE Demand-Side Managements, so think about, like, water heat load control, air conditioning load control, industrial customer interruptible programs, right?

And then, there's, you know, the more fundamental shift in energy consumption due to technology, right? So it's smart thermostats that are regulating your house without your intervention. It is smart charging systems that go on, electric cars that don't charge in the winter morning unless you do an override or something.

And so that's the type of technology that's going to come to play across time that will help shift the load shape and change the load shape.

I think one of the things we're looking at is, you know, what is the -- how do those each get factored into the IRP. So we have a mechanism of -- in place, a well-established mechanism for customer programs. I know it gets debated at times in terms of the market potential study and how much cost-effective potential is out there.

And then the other part that I believe you're referencing to, Chair Mitchell, is sort of the technology evolution, and that really comes in, in my mind, as you see -- you know, year after year, you see technologies changing and your load adapting to those technologies: Home sizes, smart homes, more electrification, not just of vehicles, but down the road, electrification of HVAC systems, which are currently, maybe not electric.

All of that is really difficult to -- depending on which technology, it has a different time horizon. So certain technologies are closer than others.

And so I know it maybe wasn't as satisfying of an answer as you wanted, but my last point on that is that you do need to think about what all of those Demand-Side resources are doing to your peak, right?

So we don't -- those Demand-Side resources are not clipping. They're generally like storage devices, right? They're moving energy around. So if

I have a time of use rate, it's encouraging you to use before or after the peak, but not during the peak.

If I'm controlling your air conditioner, I'm not clipping the air conditioner load. It's making your house warm and it's going to make up the cooling when I release that air conditioning load control, right?

So what we're trying to do is not double count. When you start to flatten that peak with these Demand-Side resources, the type of Supply-Side resources, you need to meet peak changes, and you need to account for that interaction in a way that you're not double counting a peak clipping, and so we're working hard to do that.

There's lots of opinions in the industry as to when these different technologies are going to come to fruition. I think we've got a good process in place for the customer side programs and we'll continue to track things like electric vehicles and in-house smart thermostats, and different rate designs that affect the load shape as we move through time.

CHAIR MITCHELL: All right. Last question for you, Mr. Snider, and it's just a follow-up. So, as you said, the Company's working hard, sort of prognosticate or forecast how technologies are going to impact load shape. And so where is that occurring? Is that occurring in the context of your load projections or how and where are you-all doing that?

MR. SNIDER: Yeah. I'd say three general areas. So you have the energy efficiency and DSM group, and their analytics team that is saying, you know, as I grow these programs over time, on hour by hour by hour by hour basis, what is the -- what is the hourly impact of my energy efficiency in DSM programs.

So for the customer's side, you've got that team saying what are not just my peak and total energy, but what's my hourly shape impact as part of my deployment of customer-related programs.

You then have a load research group that is looking at how is energy being consumed on our system and how is that evolving. And they work with our load forecasting group to try and produce not just our energy and demand forecast, but to help inform, you know, how do I then shape that energy over the course of the year. And, you know, so all of those groups together, come together to help inform our load forecast.

CHAIR MITCHELL: Okay. You answered the

last question I was going to ask you. There is some point in time where all of those groups come together, and there's some, you know, cross-pollination among the works of those?

MR. SNIDER: Right. So the -- yeah. So, for example, the energy efficiency, we have both a gross load forecast and a net, right, so that we can show here's -- and, you know, the interesting part there is trying to -- energy efficiency accelerates the adoption of efficiency, but then at the end of the useful life of the measure, it rolls off.

So ensuring you're not double counting or miscounting efficiency, and capturing the roll-off of efficiency. And it's all done as a coordinated effort between our load forecasting group and our energy efficiency and DSM group.

CHAIR MITCHELL: Okay. Thank you very much. Nothing further from me, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you, Chair Mitchell. Commissioner Duffley.

COMMISSIONER DUFFLEY: Thank you. Mr. Snider just answered the questions that I had, so I have no questions.

COMMISSIONER CLODFELTER: Okay.

Commissioner Hughes.

COMMISSIONER HUGHES: No questions. Thanks.

COMMISSIONER CLODFELTER: All right. Commissioner McKissick.

COMMISSIONER McKISSICK: No. It was an excellent presentation. No questions at this time.

MR. SNIDER: Thank you, Commissioner.

COMMISSIONER CLODFELTER: Thank you. Mr. Snider, I've just got a couple of things that Mr. McDowell covered an awful lot of what I would have asked.

On the pie chart, you don't need to put it up again, but I just -- because I can ask the question, I think, without it.

On the incremental renewables that you were showing in your bar graph at the bottom, how much of that was economically selected in your capacity expansion modeling, and how much of that is mandated or forced?

MR. SNIDER: I'm going to let Mr. Quinto follow up on my general answer with more detail but, you know, the forced included existing programs. So it would be 589 and all the customer programs, Green Source Advantage, others, that are mandated under 589, along with maybe some small other South Carolina -- Senate Bill 3, I think, were forced in along with the -- maybe the queue trying to estimate people that had Old LEOS that might have access to higher pricing than current avoided costs trades, how much maturation of the queue will come into place.

And then, once that bucket was developed, the model optimized on top of that, so we've got existing, plus these mandates, and then the model, you know, optimally selected.

I will say it optimally selected on the declining, you know, cost curve with, at the time, the tax policy that was in place at the time. So Mike, I don't know if you --

MR. QUINTO: Sure.

MR. SNIDER: -- or Bobby have the exact break down of models, but --

MR. QUINTO: Yeah.

MR. SNIDER: -- versus --

MR. QUINTO: Sure. I can help answer this. So, Commissioner Clodfelter, there is roughly about 4,000 megawatts of solar on the system as of the start of the IRP as it was being evaluated.

If you look at Portfolio A from the IRP, that adds about 4,500 megawatts of incremental solar between the start of the IRP and the end of the IRP, so about 4,500.

And in this case, Portfolio A, it was optimized without a carbon policy. And without a carbon policy, no economic solar was selected on top of that forecasted solar that Glen mentioned between designated and mandated, and some estimates of queue materialization, those sorts of things.

So as we see in the IRP, there's a heavy -- a correlation between the carbon price and the need for solar on our system. I will say, in some of the other portfolios, we get to higher amounts, and that's based on the representative, you know, goals of each of those portfolios. But just looking between A and B, about another 4,000 megawatts gets added.

I think it gets about to 12,000 megawatts by the end of '35, so about 4,000 in the ground today, about 4,500, based on our forecasts. And we continue to update those and make sure they're most appropriate as we go into each IRP cycle.

And then in the Portfolio B, optimized with the carbon policy, it's another, about, 4,000 megawatts on top of that.

COMMISSIONER CLODFELTER: Thank you. Thank you for that answer. Mr. Snider, one of -- I think it's the Attorney General's expert, criticized your ranking step in your sequential process for having certain -- as I recall, the criticism, it was certain unexplained groupings of units.

Rather than taking each unit individually, some of the units were grouped. Roxboro 1 and 2, Marshall 1 and 2, for example. I'd like to hear your response to that.

I mean, was -- were the groupings based upon some physical or operational leakage in those two units where you really couldn't functionally retire them individually for physical reasons or some other reason like that? Just respond to that, if you would, please.

MR. SNIDER: Certainly. And I'll allow, you know, my fellow panelists to opine if I miss something on this, because they were all involved in this.

But, yes, there -- I think the criticism, you know, first of all, started with why did we go with the older less efficient units.

And I think in that particular case, the criticism said you should have started with the bigger units, they cost more to run. And if you did them on total cost, you'd have a different ranking.

Certainly, that didn't make a lot of sense to us. You don't rank things based on gross cost. You rank them based on the value, total, you know, cost per megawatt, and the value it creates on the system.

So, you know, the industry, as we've seen it evolve over the last decade, two decades, is -- you know, we're not alone in this. You're seeing, you know, the older, less efficient, you know, more obsolete units retire first.

The later units that are more efficient, they have a much lower carbon footprint. They have much more flexibility in their ramp rates, are supercritical, have the ability to burn both coal and gas, which even further reduces your carbon footprint, and provides for additional flexibility.

Yes, they have a higher total, nominal cost, if I was looking at just nominal cost. But once you put that on a size-adjusted and value-adjusted basis, obviously that's a much different picture and ranking.

So the criticism about we should have just ranked them based on the total cost you would save by retiring them, just didn't make any sense to us and it doesn't really comport with anyone else in the industry. We know how they're retiring their coal fleet.

The second question of how they were actually physically grouped together is exactly what you've said. There are certain synergies that you get by operating a plant together, the same, you know, staff, coal handling, equipment, that if you just retire one unit, you're not getting 50 percent of the cost savings, right, you're getting a fraction of the cost savings.

And so, you know, you still have to do the upgrades, the capital investments, and it's not on a megawatt basis, because these have a lot of shared equipment, shared staff, so it does make sense from an operational perspective to group these together where it makes sense.

You know, there were some differences. So if you look at, like, Cliffside 5 and 6, why didn't we group those? Well, one's supercritical, one's subcritical, But they're also physically separated. They have separate staffs.

You know, one has 100 percent dual fuel, the other one has a very small amount of dual fuel, so they have very different roles in the system, so we didn't group those together.

So we really worked with Dan's organization to talk about what groupings make sense from an operational perspective, from a cost savings perspective.

And ultimately, grouping them into logical groupings, not only does it make sense from a physical operations and how you would probably approach retirements, you're not going to retire them all at once, but you're probably not going to retire one unit at a time.

You're going to retire groups of units. You know, so we work, you know, both quantitatively and qualitatively to say are these the right groupings. And while you can always second-guess that, we think it makes very good sense.

We've put a lot of effort in getting the right groupings, the right rankings, and, you know, our operational team agreed with those rank -- those groupings and rankings.

And then, finally, my last point is I can't reiterate enough what Mr. Quinto says, is you have to break the problem from a -- when you're looking at -- you know, traditionally, over history, you might be looking at one plant being retired or S.O. or an Optimization Model as one resource need from growth.

When you're looking at dozens of units, thousands and thousands of megawatts, you have to break that problem into manageable, discrete bites and that comport with the reality of how you run the system.

So we think we accomplished all that with a lot effort and work, a lot of input from around the Company and multiple teams, and how we did that. And so we're very -- very comfortable with not only our grouping, but our ranking.

And I know some Intervenors that would prefer us to see the big ones go first, because that's -- you know, if you don't want coal on the system, why not get rid of the big ones first, and why not make arguments for that. I get it.

I might -- I might argue that in their shoes as well, but we think our approach was much more prudent and beneficial for customers. Dan, Mike, any follow-up on that?

MR. QUINTO: None from me, Glen. I think

you did a good job of of summarizing that.

MR. DONOCHOD: Nothing else to add on that, Glen.

MR. SNIDER: Thank you.

COMMISSIONER CLODFELTER: Thank you for the explanation. Just a sort of a follow-up to that. I appreciate the explanation. How well correlated was your ranking for analysis with the dispatch order of the units?

Not their age, but the order in which they're dispatched. It looked to me, from what I've been able to learn over the last three or four years, that it was pretty well correlated.

MR. SNIDER: It is.

COMMISSIONER CLODFELTER: It -- your rank order was also pretty well correlated with the sequence of dispatching. You know, the Allen units are dispatched last, for example. And Cliffside 6 is dispatched before all the others, for example.

MR. SNIDER: It's an astute observation and that is well -- very well correlated, and has to do with Mike's -- you know, you'll see that in the capacity factor, but you do see it from a historical dispatch.

And, you know, the older units, they're less efficient, they're less economic to run, so they run last in the dispatch and create less value for consumers, So yeah. They're well correlated.

COMMISSIONER CLODFELTER: All right. Thank you for this. The next question is really just to be sure I understand your sequential process correctly. The benchmark you used for the retirement analysis was the Simple Cycle Combustion Turbine.

If it were to be the case that there was a different technology solution that produced a lower cost, benchmark, that would affect your retirement analysis, correct?

So we used the Simple Cycle Combustion Turbine as the benchmark for reasons that you canvassed. And just so I fix those in my head, because that's -- it's an important issue, I think, when we get into the second topic, for example.

MR. SNIDER: Right.

COMMISSIONER CLODFELTER: It may have something to do with how the second topic interplays with this first topic here, so give me again the reasons you selected that benchmark as opposed to any other.

MR. SNIDER: All right. Yeah. This is a great question. Again, I'm going to open it up to my team after I respond. But, a lot of the comments and a lot of the Intervenors say we used a Peaker and that's all we allowed. That is flat out incorrect.

The Peaker was simply used as a benchmark to establish when a retirement should be considered, because the Peaker is the lowest capital cost unit that's available to replace.

Every -- I've said this in other dockets. The Peaker Method is basically inherent across everything. You'll only pick a more expensive capital unit if the efficiencies it creates on your system justifies spending the additional capital.

So the Peaker is the lowest capital unit you can replace something with. And you go to a more expensive capital -- on a dollar per megawatt basis, you go to a more expensive unit if the production cost value, if the system value, justifies the incremental capital.

So that's why the Peaker Method is used in the CONE, Net CONE, PJM. It's used in the utility cost test for EE and DSM. It's used to establish PURPA avoided cost rates. It is a fundamental framework that is used in multiple areas of the industry.

Importantly, and very, very important is we did not limit the model to selecting a Peaker. The Peaker, being the cheapest capital unit, was to -- used to help identify The When, and then, the models were allowed to select whatever was the most economic at that point in time.

COMMISSIONER CLODFELTER: I understand the distinction, but stay with me here for a moment.

MR. SNIDER: Sure.

COMMISSIONER CLODFELTER: It -- again, I understand we're on The When question. We're on The When question. I get it.

MR. SNIDER: Okay.

COMMISSIONER CLODFELTER: The benchmark, though, you select, as we agree, the benchmark can have some impact on the decision about When, what the model spits out.

So shouldn't the benchmark that you choose mimic the function that the resource being analyzed is performing on the system? And another way of asking that question is --

MR. SNIDER: Yeah.

COMMISSIONER CLODFELTER: -- is Cliffside 6 really -- are the Marshall units really providing the same service, system services as the Allen units? Should they have the same benchmark as the Allen units if they're performing a different function? If they're functioning as --

MR. SNIDER: Right.

COMMISSIONER CLODFELTER: -- intermediate plants, for example, are not, you know, functioning as pure Peakers, should they have a different benchmark?

MR. SNIDER: So very, very good question. And what you'll see in that step four that -- that Mr. Quinto lined out is while the Peaker is for The When, because those are more intermediate, the actual What that was selected was a combined cycle.

And so the only question you have to ask is, again, you know, by and large, what's driving the When decision is the capital. I'm going to avoid a major overhaul at the plant.

And now, I have to -- is -- am I better spending the money on the major overhaul at the plant, or am I better spending money on my replacement generator.

So you start by saying is -- if the cheaper replacement generator is a better option, that's step 1. Then, okay. Then, that's The When. Then you say, hey, that's not the function. To your point, that's not the function.

A combined cycle serves that need more efficiently at a lower cost for customers, in your example. And then you can go -- and to Bobby McMurry's point of using that Production Cost Model as a check, you can then go back and say, because I picked something other than Peaker, was there enough benefits maybe for me to move that up a year?

So you're fine-tuning that -- you can fine-tune that When if you want to in another iterative loop, but the key driver of when to retire is sort of capital on capital, and the production cost does come into, then, what's the most efficient.

And then, importantly, we're going to talk about this in the All Source process is, that's just a placeholder technology for the IRP planning purposes. Then, you'll run an RFP, and any resource, Peaker, combined cycle, batteries paired with solar.

Any of those that are capable of fulfilling the need that you've just retired will be allowed to fully -- you know, again, on my funnel, you know, you start with this Peaker Method, then you have an IRP Optimized resource, and then you have a market-based selected resource, and you're winnowing in on the optimal result.

But, really, a lot of this is, if you actually talk to people who do a lot of retirement analysis, the key is not carbon price. It's capital on capital.

So you start with the cheapest capital to avoid spending capital, and then you go from there. And then, you select different resources for efficiency.

And then, when you go the market, you may even select a -- yet a different resource. So I think there's -- there's a -- the Peaker was a perfect method for using The When to help make this 15 quadrillion options that Mr. Quinto pointed out manageable.

You have to start to hone in on The When, and then The What, you say, is there even a better resource than this low cost capital, the cheapest capital. Is there something that's more expensive capital, but does a better job on the system? You're certainly wanting to ask that question.

And then, you can even follow up and say, would I tweak my When based -- you know, based on that decision. To be clear, you know, we didn't -- we only went so many times through this process, but when you start to approach the ones that are near term, you'll -- you may be able to ask that question.

So I know that was a bit of a long-winded response, but I hope it was responsive to what you're trying to -- to ask.

COMMISSIONER CLODFELTER: It's very helpful in helping me get my head around the stuff that I don't deal with on a day-to-day basis like you do, so thank you for that.

That's all I have, and I think we're sort of completed with this presentation, then. Thank you all. Very efficiently done and very clear. We appreciate it.

MR. SNIDER: Thank you, Commissioner.

COMMISSIONER CLODFELTER: Mr. Smith? Ben Smith, are you out there?

MR. SMITH: Yes, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: I think in the sequence of things, we move to the group of Intervenors next. I'm looking at my clock here, and you've got an hour total. I don't intend to force you to break up things artificially.

My question is I don't know if you've got multiple presenters. And if you have a presenter who could efficiently get through by 1:00, then we'll take our lunch break at 1:00.

If you do not, then we'll go ahead and take our lunch break now, and then come back in at -- and start with your presentations.

So my question to you is do you have a presenter who could effectively get through between now and 1:00. Thank you for the question. I'm going to defer to Gudrun Thompson, who we co-sponsored the presenter on this topic with. So I see she -- her picture is up, so I will defer to her.

COMMISSIONER CLODFELTER: Ms. Thompson?

MS. THOMPSON: Thank you, Mr. Smith. Thank you, Commissioner Clodfelter. Again, Gudrun Thompson appearing on behalf of the SACE parties. We will be presenting jointly with CCEBA and NCSEA, Rachel Wilson, and Jeremy Fisher on this topic.

Their prepared presentation should only take about a half hour by hour I think we could get that done before 1:00 lunch and perhaps questions after lunch, if that's amenable to the Commissioner.

COMMISSIONER CLODFELTER: It is amenable. I don't want to force you to break your presentation. So if you think you can get done by 1:00, and then we'll break for lunch then and come back on questions.

MS. THOMPSON:: Let me just ask Mr. Fisher or Ms. Wilson to chime in if you think you cannot -- or, I guess, to confirm you think you can be finished by -- so that we can all break for lunch at 1:00.

MS.WILSON: This is Rachel. I think that we can. And if we can't, it would be maybe one to two minutes past the time.

COMMISSIONER CLODFELTER: All right --

MS. THOMPSON: Okay. Perfect.

COMMISSIONER CLODFELTER: -- then. We'll go ahead, and we'll turn the presentation over to the group of Intervenors.

MS. THOMPSON:: Thank you, Commissioner Clodfelter. So, again, just for the record, Rachel Wilson and Jeremy Fisher will be presenting on methodologies for evaluating economic retirement of coal-fired generating units.

On behalf of SACE et al., as well as Carolinas Clean Energy Business Association and North

Carolina's Sustainable Energy Association, I'll just briefly introduce each of them, and then turn it over to them to run the presentation and present.

Ms. Wilson is a principal with the firm of Synapse Energy Economics, who is the primary author of the Synapse Report submitted by SACE et al., CCEBA and NCSEA in this docket.

She's an Energy Policy and Economics Analyst with more than a decade of experience in both utility resource planning and energy systems modeling, whose work focuses on evaluation of the need for new energy infrastructure, power plant economics, and compliance with environmental regulations.

Mr. Fisher is a Senior Advisor for Strategic Research and Development with the Sierra Club's Environmental Law Program, where he advises on a wide variety of electric and gas system planning issues.

Prior to joining the Sierra Club in 2018, he spent 10 years at Synapse, where he was a technical consultant on energy and environmental planning issues for public interest entities, and both state and federal regulators.

And, with that, I will turn it over to Ms. Wilson and Mr. Fisher.

MS. WILSON: Great. Thank you, Gudrun. And could I just request presenter access from John so that I can -- there we go.

All right. Good afternoon, everyone. I'm going to try not to stand between you and your lunch, so I'm going to jump right in with the agenda for our presentation today.

We have a few key topics relating to Duke's Coal Retirement Analysis that we plan to discuss. First, we'll note the primary components of our critique of Duke's analysis. Then, we'll discuss some of the challenges, generally, to utilities in performing this type of fleet-wide analysis.

Next, we'll describe the capabilities of the EnCompass model to utilize an Endogenous Retirement Methodology to do this type of evaluation. And, we'll also describe the methodologies that other utilities have recently used in their own unit retirement studies. And, then, lastly, we'll present our recommendations for Duke going forward.

The purpose of Integrative Resource planning, generally, is to determine the set of resources that are going to best meet forecasted customer demand at the least cost. And this type of analysis has -- has historically focused on the new Supply-Side resources that will be needed to be added to the system to meet growing loads.

However, lower demand growth, combined with aging fossil fueled infrastructure, has led to a need to also evaluate the economics of existing resources as part of the IRP process.

The valuation of existing facilities requires us to ask new questions as part of our analysis. Do the coal plants economically serve customer requirements or is there some other combination of resources that would be lower cost?

Do we expect that our coal plants will operate economically in the future? And what is the date at which we might expect the operating costs to exceed the cost of replacement resources.

And, then, finally, for a fleet-wide retirement analysis, what's the best and most economic combination of retirement dates that also allows us to reliably serve customer load? These are the kinds question that we expect Duke to be asking as part of its unit retirement analysis.

You've heard that Duke's Coal Retirement Analysis consisted of three steps. The first is to rank the order of retirements based on capacity, with the smallest units retiring first.

Duke's second step is to use its Sequential Peaker Method, which compares the cost to operate each coal unit with the net cost, which is the capital cost minus the energy value of a new Gas Fire Combustion Turbine. This is the step at which the economic retirement date for each unit is determined.

And, then, Duke's third step is to optimize the set of replacement resources that come online when each unit is retired, and I'll discuss our critiques of each of these steps in the next slide, but I actually want to touch on this "Other Issues" box, that's shown here, before I move on.

And, first, I'll note that what is supposed to be an economic analysis of unit retirements, produced retirement dates that are remarkably similar to those that came out of Duke's 2019 depreciation studies. And it seems highly unusual for these economic dates to so closely mirror the dates estimated by an engineering-based study.

Second, there's a lack of transparency to Duke's retirement analysis. The methodology wasn't informed by any sort of stakeholder process. The analysis itself had to be requested through the discovery process, but was marked confidential, and thus was only available to a subset of Intervenors.

And then, lastly, the specific inputs and constraints used by Duke were often unclear, given that the analysis was done in System Optimizer, which none of the Intervenors had access to in this docket.

So it's almost impossible to tell if the retirement dates, specifically those that are farther into the future, really do reflect a high economic value of specific coal units, or if they result from built-in barriers to replacement.

And one such example of a barrier would be the inclusion of undepreciated plant balances as a cost to retirement, when these sunk costs should in fact be excluded from this type of forward going analysis. So that's the type of thing that we would want to remove from an analysis if it were present in this case.

So, again, the first step in Duke's methodology was to establish and order for unit retirements. And rather than attempting to answer that key question that I described above of, do the coal plants economically serve customer requirements, and then ranking them according to their value, which I'll just clarify, you know, we do believe that it's value, not simply cost here.

Duke simply ordered the units according to capacity with the smallest units retiring first. And, so, the Company's economic retirement analysis was -- it totally ignored the actual economics of these coal units.

The second step in the process was to utilize Duke's internally developed Sequential Peaker Method, which compares, again, the net value of each existing coal unit to the cost -- net cost of new entry, or Net CONE, for a new Gas Fire Combustion Turbine peaking unit.

A Net CONE is calculated by subtracting the net energy value from the capital and fixed costs for the unit. So underlying each of these calculations, both the Net CONE and the net value for the coal unit is some embedded assumption about the value of energy.

You heard that Net CONE is a -- a common method that's used for valuation in other dockets. And I just want to note here that is evaluation for capacity costs and doesn't include that energy component that is very essential here.

So Duke uses the rank order set in step 1 to establish these unit retirement dates. Oh, I'm sorry, to establish the order for unit retirement dates. And then the actual dates for the units in the rank order are locked into Duke's analysis before it proceeds with the SPM analysis for each subsequent unit.

So as an example, the Allen units in Cliffside 5, which retire earlier in the analysis period, are considered retired when Duke evaluates the retirement date for the Mayo unit.

CTs aren't known for producing large quantities energy. And so by assuming a CT replacement in this component of the analysis, Duke's method is essentially giving the remaining coal units on the system additional value, because they, then, must make up the majority of the energy that's been provided by those units that are now retired.

That's not a method that's consistent with reality, because a utility would be replacing any retired generation with other resources as it's retiring the unit, and that could be a portfolio of a variety of different resource types.

So while there may be changes to the operation of the remaining coal units, they wouldn't necessarily increase in value, so those later coal units wouldn't have a higher value necessarily as a result of the retirement of the previous units.

So consistent with this reality, rather than simply comparing to a new CT, Duke should have instead looked at a replacement portfolio that consists of a -- excuse me, a variety of different resource types that provide the same services in the aggregate as that retiring coal plant.

And so to do this, Duke would need to include the capacity Optimization component of its analysis at this point in time, rather than holding that Optimization to step 3.

Fleet-ride unit retirement analyses, particularly of this magnitude, can certainly be challenging. I agree with Duke on that point, and we've highlighted some of those challenges here, some of which are redundant to what you heard this morning.

But, I've placed them into buckets, and the first bucket deals with the challenges associated with evaluating the retirement of a large number of units. Each unit retirement is going to have an effect on the operation and thus, the value of the remaining plants in the system.

But it's also true that the replacement resources that are selected as each unit retires will have a similar sort of effect on the value of those remaining units. And so this makes the order of retirements particularly important and makes it even more egregious that Duke skipped that economic evaluation of its units in step 1.

And then, lastly, here we see that the retirement of multiple units is going to have transmission impacts that need to be considered.

So in that next middle bucket, we have the impacts of planned retirement on the spending that might be incurred or avoided at the coal units and how we might account for those costs.

So we might expect that as a unit approaches its retirement date, a utility is going to spend less money on capital investments to keep the unit in top condition. Estimating that capital that could be avoided is certainly challenging.

And then, next, for plants with multiple units, as you heard, there are certain costs, particularly fixed on them, that may not scale directly with the retirement of individual units.

So, for one example, let's say that the

Roxboro plant, which has four units, has annual labor costs of a million dollars. Retiring two of those four units probably wouldn't cut those labor costs in half, and so some other ratio would need to be applied to figure out what those forward going costs would actually look like.

And then, lastly, in some instances, utility might have long-term fuel supply contracts, and they would incur some sort of cost penalty if those contracts were to be cancelled.

And then, lastly, this third bucket deals with replacement resources and the challenges that are associated with finding sufficient non-fuel or non-fossil options to replace those large units.

And a large scale All Source resource -- All Source Procurement process, which is coupled with continual market testing, is the best solution to address this particular challenge.

So I'm going to shift gears for a second to talk about Endogenous Retirements. And we were asked specifically to talk about this and how the Endogenous Retirement Methodology might be used in this type of analysis.

So this is a big term that people outside of the modeling sphere might not necessarily be familiar with. And so Endogenous Retirements are just those that are internal to the model.

So that means that the model is making the decision if it should retire a unit, and if so, when to do that. And it's doing that as part of its Capacity Optimization process.

The EnCompass model, which Duke is transitioning to for its next IRP, has both Capacity Optimization and Production Cost capabilities. So it can take those two steps and combine them into one.

It also has a few specific settings relative -- that are relative to Endogenous Retirements, that can be adjusted by the user within the model. So these include either allowing for economic retirements or not, specifying the first year that a unit could become eligible for economic retirement.

And then, lastly, putting a limit on the number of megawatts that could be retired in a given year. So if we allow for the Endogenous Retirements capabilities within EnCompass, the model's decision is based on a calculation of unit profitability. And so for a unit that exists in an RTO like PJM, this is just the summation of its energy capacity and ancillary revenues, minus its costs.

For Duke, which is operating in a vertically integrated area, this means that a unit's retirement is based on the cost of providing the next megawatt. So whether that -- that could be from an existing resource on the system, or it could be the cost to bring a new unit online.

There is one important limitation to using the Endogenous Retirements functionality, and it relates directly to those challenges that fell into bucket two on the previous slide, and that's namely how early retirement might change future investment decisions at a given year.

And I'm going to turn presentation over to Jeremy right now to discuss the retirement studies that have been done by other utilities.

MR. FISHER: Thanks so much, Rachel, and thanks Commissioners for having us today.

So I'm going to briefly touch on just two different utilities: PacifiCorp, which serves six states throughout the Northwest, and Intermountain West, and NIPSCO, Northern Indiana Public Service Company, that serves areas north of Indianapolis in Indiana.

And I'm focusing on those two because they're sort of similar types of scopes to Duke in different ways. PacifiCorp is not the same size as Duke, but -- it verges on a similar size, but has a substantially larger coal fleet relative to its overall generation capacity.

And NIPSCO, while being a substantially smaller utility, has a far larger coal burden, and both have done some very interesting coal retirement assessments that we think have cumulatively better practice than what we saw here for the Duke IRPs.

So I'm going to actually start off with PacifiCorp's practice back in 2013, so a good 8 years ago. We had an Integrated Resource Plan that was filed by PacifiCorp that first introduced it, actually Endogenous Retirement through the System Optimizer model, So the same mechanism that Duke is using here.

And some of the same questions and problems that Duke raises in this particular IRP of how are they going to deal incremental capital expenses, and the commissioning costs and coal contract damages, and unknown fixed O&M groupings, were actually assessed and thought about by PacifiCorp, at that time, and to some extent, solved.

And so questions about how do we deal with new capital expenses that are incurred during the planning period and allowing the model to endogenously take those into account and still retire, were successfully solved in that space.

Just to put it in context, PacifiCorp's coal fleet in 2013 amounted to 52 percent of its capacity, so close to double what Duke is looking at as a fraction of its overall fleet.

Over on the right, these are just some pullouts from the PacifiCorp IRP back in 2013, where it's explicitly discussing that as it was looking at coal unit retirement, now, alternatives.

Down over here on the right side, it was considering the impact of decommissioning costs and incremental and -- both environmental and run rate capital expenses, and coal contract damages, which are actually substantially more difficult at the Mine Mouth plants that PacifiCorp is dealing with than Duke often has to deal with.

And, then, just pulling out that one paragraph that notes in the first very line there, that the System Optimizer model successfully, in this case, takes both into consideration the compliance alternatives, meaning the retirement of the coal units, as well as all of the alternatives that could be brought into place instead of those coal units, and so is doing that work endogenously within the structure of the model. Next slide, please.

And so within the 2013 IRP, PacifiCorp ended up running a number of different types of scenarios for different pricing worlds. How might gas prices, CO2 prices, and coal prices evolve in the future?

And one of the things that comes out quite strongly in that is that as PacifiCorp started to look at those different sensitivities into its system, it fundamentally changed the assessment of which coal units would be brought offline at which dates, as you would expect under those different types of pricing scenarios.

And we can see that from -- well, one of their sets of scenarios, at the time, what was considered a low gas -- sorry, if you could keep us with that same slide. Thank you.

What was at the time considered a low gas, and what might, now, be considered modest CO2 prices, the vast majority of PacifiCorp's fleet retired by early 2022. There was some differentiation between the different runs, depending on what other types of assumptions were otherwise put in place.

While PacifiCorp subsequently, actually, put an end to the use of Endogenous Retirement within its IRP structures, it did actually retain many of the same components that are used to feed that Endogenous Retirement mechanism. If we flip over to the next slide.

In 2018, leading up to the 2019 IRP for PacifiCorp, PacifiCorp was ordered by the Oregon Commission to conduct a unit by unit assessment, and so this is a space in which the Commission having long looked at a place where it wasn't getting enough feedback in terms of the value of the PacifiCorp's individual coal units.

And trying to really understand that at a somewhat more granular level, required that PacifiCorp conduct an assessment that looked at the value of each individual coal unit incrementally, and then looked at the value of retirements that took into account the least economic units on PacifiCorp's system.

And so in June, 2018, there was a confidential version of that provided as part of a closed docket process. But in December 2018, PacifiCorp provided a unit by unit assessment publicly, the results of which I'm showing over here.

And the results of that show that the majority of PacifiCorp's fleet was actually uneconomic on a forward-looking basis, but I think it's worthwhile pausing for just a half a moment on a couple of key points here.

So you might look at this and ask how is the mechanism that PacifiCorp employed looking at a unit by unit assessment here fundamentally different than what Duke has done in its 2020 IRP.

And there are a couple of really key factors here. First, for every unit that was retired and replaced, the model was allowed to choose an optimal retirement portfolio. And so, in some cases, it is an uptick of energy from some existing units, with an addition of new resources that are coming online.

In some cases, it's exclusively new units that are coming online, and that ended up being an entire portfolio of options, including energy efficiency, increased energy efficiency, Demand-Side Management and renewable resources.

A Second key component is that after having run System Optimizer to determine what an optimal portfolio replacement might look like for each unit, PacifiCorp then ran it through a Production Cost Model to assess the reliability implications and make sure that they understood the costs and the implications for the rest of the system before having taken off each individual units. So what I'm actually showing you here is the outcome of that production cost modelling run, not the System Optimizer run.

And then, finally, PacifiCorp showed another component of this that I'm not showing here, in which they took each of the units and sequentially stacked them, so taking the least economic units to the most economic units, and starting to look at the incremental retirement of each one of those, at each step allowing full Fundamentally different than what Duke has actually done here.

So while this is different from Endogenous Retirement, it's a mechanism that allows for a substantial amount of transparency. Next slide, please.

At a quite granular level, the Oregon Commission, again, asking for information to be made more transparent in this process, actually received this outcome from PacifiCorp of showing the avoided cost of each individual coal unit and the replacement cost of what's put in place.

So as a -- in this case, not until a particular coal unit was taken offline, it had a reduction of fuel variable O&M emissions and an increase in decommissioning costs, and was replaced with units that had some element of fuel cost, variable O&M cost, and then also market sales and new equipment that was put in place.

And this level of transparency was actually a really important way of understanding how all those units interacted in PacifiCorp's system. We think this is an incremental value to Endogenous Retirement Assessment. It doesn't necessarily replace it in full. Next slide, please.

Turning to NIPSCO in northern Indiana, this is a utility that, while substantially smaller than Duke, actually had close to 70 percent of its capacity in 2018 fired by coal. So five quite large coal units, four at this plant, Schahfer, and one at Michigan City.

In advance of the 2018 IRP, NIPSCO actually issues a quite broad ranging All Source request for proposals, and got in a substantial number of bids on low cost wind, solar, storage and efficiency that it could otherwise put onto its system.

And, so, that RFP, done in advance of the IRP, allowed NIPSCO to properly assess what the market costs of those alternatives could be, and then, be able to look at its retirements with respect to those replacements.

And as you can see in this figure at the bottom, for each one of the sets of retirement clusters that they looked at, whether it was two units, four units, or all five of these units, they were able to successfully find, in this case, non-fossil alternatives that met their requirements at a lower cost than they otherwise would have through fossil replacement. Next slide, please.

Similar to the way that PacifiCorp ended up stacking its units for the unit by unit assessment, this was not an Endogenous Retirement that was done by NIPSCO, but they had a fewer number of units in this case, and so they looked at combinations and permutations of those unit retirements.

The first question that they asked is what's the fundamental value of each of these units in 2023. And then, adding onto that, saying, is there a better combination of retirements that happen in 2023 or 2028, and looking at various opportunities to avoid impending capital requirements that would come through environmental obligations. So they use these eight different scenarios, including a baseline. Next slide, please.

And, ultimately, disclosed quite clearly what are the costs of each of those particular scenarios, So what's the incremental value of retiring another set of units off of the system.

And what you can see here, on this costs to the customer, is that their determination was the more coal that's retired off of their system, the higher value there was to their customers.

And so, basically, there is a lower cost overall from the net present value to their customers for retiring their entire system as early as feasible.

Ultimately, they made the determination that attempting to retire all of their coal units, at that point, just five years into the future, had risks of being able to bring enough resources online, in order to be able do that 70 percent replacement of their entire system.

And, so, they selected a preferred

retirement path that delayed the retirement of, in this case, the Michigan City unit, but still advanced the retirement of those Schahfer units over here as seen in this portfolio number 6.

And, actually, at the end of the day, they have now decided that two of those units, the Schahfer's 17 and 18 units, will actually be retired in 2021.

And, so, there's been a continuous evaluation of those portfolios on a go-forward basis. NIPSCO has also successfully come forward with non-gas alternative replacement portfolios that they've indicated are a lower cost than anything else that they could otherwise put in place.

So, it's a very successful mechanism of looking at the value of those coal units, and then finding an alternative replacement, based on the valuation that they can get through this All Source IRP.

And I believe, for our last slide, I'll turn it back to Rachel.

MS. WILSON: Okay. Thanks, Jeremy. We started this presentation with a series of different questions that Utilities should answer when doing a retirement analysis.

We believe that Duke and its analysis presented an answer, but didn't necessarily show its work with respect to the questions. So we, therefore, recommend that the Company update its study and revise its methodology, such that it can demonstrate that its retirement dates are economically optimal.

Use of Endogenous Retirements is feasible if we correctly account for these future costs that might be avoidable with early retirement, but we'd also recommend that Duke do a unit by unit analysis, selecting one or more near-term retirement dates and comparing those to a scenario in which the unit continues to operate, and then, compares the costs of each of the resulting resource portfolios over the length of the analysis period.

So those lowest value units, whatever Duke finds them to be, would then be stacked to determine optimal combinations of retirements.

When considering replacement resources, the coal retirement should be co-optimized with a number of different Supply and Demand-Side resources that include energy efficiency, demand response, solar, wind and storage of various durations.

And then, lastly, we'll note that this type of forward looking analysis should not include costs that are considered to be sunk costs, like any undepreciated plant balances.

And with that, that concludes our presentation.

COMMISSIONER CLODFELTER: Very efficient. Thank you both. We'll let folks think about this over lunch break and come back, and pepper you with questions afterward, after they're refreshed.

MS. WILSON: Wonderful.

COMMISSIONER CLODFELTER: So let's break now, and we'll come back at 2:00 p.m. And while we're on break, please, everyone go on mute and turn off your video. Thank you. See you all at 2:00.

(Whereupon, the Proceeding was adjourned for lunch to be reconvened at 2:00 p.m.)

C E R T I F I C A T E

I, TONJA VINES, DO HEREBY CERTIFY that the proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

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Tonja Vines