BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:
DOCKET NO. UNDOCKETED

REVIEW OF THE 2024 TEN-YEAR SITE PLANS FOR FLORIDA'S ELECTRIC UTILITIES.
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PROCEEDINGS: COMMISSION WORKSHOP

COMMISSIONERS PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Tuesday, September 10, 2024

TIME: Commenced: 9:45 a.m.
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Room 148
4075 Esplanade Way
Tallahassee, Florida

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I N D E X

P R O C E E D I N G S

CHAIRMAN LA ROSA: Excellent. Well, good morning, everybody. Just it felt like it was a few seconds we saw -- we saw you.

Today, again, is September 10th. I would like to call to order our review of the 2024 Ten-Year Site Plan. I would like to turn it to staff, if you would please read the notice.

MR. FAROOQI: Good morning, Commissioners. By notice issued on August 29th, 2024, this time and place has been set forth for a workshop. The purpose of this workshop is set forth more fully in the notice.

CHAIRMAN LA ROSA: Excellent. Thank you.

With us is Mr. Vince Ordax. I'm going to throw it to him -- or throw it back to you guys to introduce him.

MR. FAROOQI: Yeah, this is Vince Ordax with the FRCC, and he has a presentation for us.

CHAIRMAN LA ROSA: Excellent.

Mr. Ordax, welcome. We are looking forward to your presentation, as we do annually.

MR. ORDAX: Thank you. I appreciate it.

CHAIRMAN LA ROSA: Of course.

MR. ORDAX: Good morning, Chairman La Rosa,

Commissioners. I am Vince Ordax. I am the Senior Director of Planning at the FRCC.

I provided you a summary of our analysis of the aggregated 2024 Ten-Year Site Plans --

CHAIRMAN LA ROSA: Do you mind maybe moving your microphone down a little bit?

MR. ORDAX: Is that better?

CHAIRMAN LA ROSA: Yeah. Sounds good.

MR. ORDAX: Thank you.

The aggregated Ten-Year Site Plans that were filed by the individual utilities. Our mission is to coordinate a safe, reliable and secure bulk power system in Florida. We are a not-for-profit corporation formed in the 1970s. We have 20 members, utilities in Florida, investor-owned utilities, cooperatives, municipalities.

The FRCC carries out activities on behalf of our member utilities, including being a reliability coordinator, overseeing the electric grid, and the planning coordinator coordinating long-term transmission planning.

So the topics that I will cover today will include overall summary, the process that the utilities use for integrated resource planning, and the aggregated load forecast and capacity

additions, reserve margins and generation mix in the Ten-Year Site Plans, as well as reliability considerations of both solar additions and the natural gas infrastructure.

In addition, this year I will discuss transmission adequacy and FERC Order 1920.

So the data from the individual utility integrated resource plans are brought together by the FRCC to create what we call the loading resource plan. So we use, you know, the members we use and update their load forecasts annually, and they take into account, you know, energy, fuel, economy, resources, including plans and modifications for retirement. And they will compare those with any needs that may be short some years, whatever needs of resources they have. And then they consider options, such as supply-side options, demand-side options. And they take into consideration costs and operating data.

From here, they will go ahead and evaluate several alternatives, and then they will choose the best alternatives. And they go ahead, and that's what creates the individual resource plan.

So for -- at the FRCC, what we do is we aggregate the individual plans, and we create

Florida resource plans, as I mentioned earlier. Now, this plan we provide -- the aggregated data, we provide to the Public Service Commission, so you guys have a copy of that. We also populate our planning models. Loss of load probability studies are produced from this data as well. And we perform transmission studies, and several reliability assessments that we will talk about later in the presentation. And some of this data is also provided to NERC and SERC for their assessments that they do annually.

So turning to the load forecast. Firm summer peak demand growth is projected to be about 1.3 percent per year throughout this 10-year horizon. And the energies that growth is expected to grow about one percent per year. As you can see, the demand response reduces firm summer peak demand by 5.3 percent by 2033. Customer-owned distributed solar is expected to reduce summer demand by nearly 4,000 megawatts by 2033.

So the factors that surround the load forecast really include, you know, the obvious. The population growth is projected to remain strong in Florida. The impact of the electric vehicles is forecasted to grow to about 2.8 gigawatts by 2033.

This is an estimated number.

Currently, there are no impacts from potential data center load reflected in the individual utilities load forecasts, but the entities are obviously monitoring this particular thing.

Energy efficiency codes and standards, and conservation, and distributed solar are dampening energy use growth throughout the 10-year horizon. And wage and income growth have not kept pace with employment growth.

So now we are getting to the actual, what we call the firm peak summer demand forecast. And here, we are comparing 2023 versus 2024. The 2024 forecast is the solid orange line. And the dashed blue line is the 2023 forecast. As you can see, they are pretty close to each other. They have about the same growth. In the later years, 2024 is growing a little bit faster.

Next we have the comparison of the net energy for load. You can see again the solid orange line is the 2024 forecast, and the dashed blue line is the 20 if forecast. You can see that the growth rate is about the same. The slope of the line is the same, but it is a little higher, and that was kind of pushed up -- we did have about 2.6 percent

higher energy actuals for 2023 than we had before. So the forecasters adjusted the expected energy use in the future.

So here, we have sort of -- kind of to explain what the different terminology that we use here for the demand. The yellow line on top is really the projected demand. You know, if you didn't have any demand response for energy and efficiency codes were not in place, so that would be the demand without those.

The blue line, which is slightly below the yellow line, reflects the impacts of the energy -- the energy codes and standards that are expected to have that kind of an impact on the demand.

And then the final one is if we include the demand response, then we come down to what we call projected firm peak demand. That's the orange line. And so that's -- the actual numbers that are used to calculate the reserve margins, is based on the firm peak demand. And actually, throughout this whole presentation, all the forecasts that you see here include the impacts of energy efficiency codes and standards.

So this chart shows the incremental generation changes by year. You can see, you know, coal is

blue, and you can see there is some retirements taking place, you know, in 2024 and '26 and '29. We still have also natural gas, some older units retiring later on in the 10-year horizon, they are, like, in 2028.

Then on the addition sides, you can see there is a significant amount of solar being added. That's the -- kind of the yellow bars. And then the orange bars are the natural gas and then the gray bars are the battery.

One thing to note here, on the solar, these are the firm capacity values, not the nameplate values for solar, which brings us now to the reserve margin calculations.

You know, the orange bars are for showing the reserve margins throughout the 10-year horizon for summer, and the blue bars are representing the winter. And you can see that in all of the years throughout the 10-year were above the 20 percent mark.

One thing to note, and you see that you have higher reserve margins in the winter. And that's kind of driven by the thermal capabilities so some of the units, they can actually put out more -- more capacity in the winter months because of the

colder air. All of these, like I mentioned in the previous slide, reflect the use of demand response. And so that's reflected in the reserve margins.

This next slide shows the forecasted firm summer resource capacity values. And you can see, you know, for 2024, from natural gas, we have -- 75 percent of the total fleet is gas, then expected to slightly drop by down to 71 percent by 2033.

Solar is expected to grow from the seven percent in 2024, up to 12 percent in 2033.

Coal is green, and you can see it's going down from six percent to four percent. And that's, you know, reflects those retirements that we saw in the other slide.

Nuclear is remaining fairly constant.

Battery is going from one percent up to four percent.

This slide shows the net energy for load by fuel type. So here, you know, there is -- the biggest change, as you can see, is gas is expected to be 72 percent of the energy this year, and it's going to drop to 54 percent by 2033. Solar is the big increase here, from eight percent to 31 percent by 2033. You can see that, you know, nuclear is pretty constant, and coal will be dropping from

three percent down to one percent.

So I am going to talk a little bit about solar generation output variability. There is usually a lot of talk about what is a variable energy resource, and why do we call it that. And so this slide is actually actual output from solar in the FRCC region for -- from May 15th of this year.

You can see that the nameplate solar is up there, about 7,500. We are getting an output of, say, on this particular day, of 4,500. And then you see on the upper right-hand, you see a little map, the radar map, we have the storms coming through. And then what that does is we had a drop of 1,200 megawatts, you can see. In about a 90-minute period, we dropped 1,200 megawatts, and then it, in about the next two-and-a-half hours, we got the 1,200 back that we dropped.

But in that interim there -- so the traditional generation is really used to manage the variability of solar generation, right? We have something you can actually control to meet the demand. So this is what is meant by output variability, or, you know, variable energy resource.

Now, keep in mind, this is for one particular

day. The curves are similar. In other days, you don't see any dips at all, right? You know, they will -- they will be pretty solid all the way through.

This slide is another daily -- it's a daily load curve for May 9th of this year, as an example. You know, this is trying to show the -- what the traditional peak hour would be normally. So the orange line on the top is the demand that's being served that day, and then the blue line is the demand minus the output of solar. So that means that the blue line is what the remaining traditional generation needs to serve.

And so without solar, you can see that, you know, around hour 17:50, about 5:50 in the afternoon, is when we would have peaked. That would have been the summer peak for that day, or the peak for that day. And then when we take into consideration the effects of solar output, it actually shifts this, it shifts the daily peak into what we call the net solar, and it shifts it down -- up to -- or past the 2010, right? That's like a little bit past 8:00 in the afternoon.

And so there is less -- obviously, if that's the peak for the day, as you shift your daily peak

later in the afternoon, there is less sun available at that time. So any incremental additions of solar will be counted less towards the firm capacity, right? Obviously, during the day, they are still generating power and they meet -- as you saw from the net energy for load charts that we had earlier.

And this slide is kind of just to kind of complete the slides on solar. It's January 21st of this year. It's what we call, like, a typical winter day. So you can see, we have two axis here. So the axis on the right really corresponds to the solar curve there in dark blue and the yellow line on top for the nameplate capacity. And then the scale on the left is for the, I guess the magenta and the green line is for load. And then the net load, which is the load minus the output of solar.

You can see our typical load profile in the winter is we peak in the morning, around 8:30 in the morning, and then we have another afternoon peak, you know, past 6:30 or so in the afternoon. You can see, really, that during these -- these times that we are peaking, you know, the solar is very little, especially in the morning. There is nothing in the afternoon for that second peak. And

so the contribution of solar for -- as capacity for winter peak is minimal. So most of the entities call -- consider very small amount of capacity for the winter peak, and it's reflected in the reserve margin's calculations that way. It's very -- for reserve margins, we use the values at peak.

So this slide shows a comparison of the nameplate solar compared to the firm solar capacity attributed by the utilities. The nameplate is shown in orange, and the firm solar available at the time of summer peak is the blue, right? So in 2024, you can see that the firm capacity is about 50 percent of nameplate. By the time we get to 2033, it's about 22 percent of nameplate for the reasons that we talked before. Since we are shifting the actual net peak later in the afternoon, there is less contributions from the incremental solar towards the -- that peak.

So this is sort of a brief summary here, but with the significant growth of solar forecasted, utilities in the FRCC are working to understand the reliability considerations of this change in resource mix. At the current levels of solar penetration, members have been able to reliably incorporate solar without negative operational

impacts.

As we saw, solar shifts the period of the lowest operating generating margins, the net peak to later in the day. And the planners are assuming lower capacity value to solar as penetration increases in and the net peak moves to a time of the day when less solar energy is generated. Planners are evaluating resource adequacy beyond the summer and winter peaks. Utilities are also developing experience with these resources, understanding the importance of solar output, forecasting and integrating that into the generation dispatch to ensure reliable and efficient operations.

Now, we continue to review lessons learned from other parts of the country that have already have had high levels of solar, you know, such as California and ERCOT.

And, you know, finally, members are studying the impact of solar and batteries on the resource adequacy measures, and we are doing additional calculations and analysis to ensure that we are considering the attributes of these resources appropriately. I know many of the members are also doing energy hourly energy assessments to make sure

that there is enough energy for all hours of the year, not just the peak.

This table shows -- or the chart shows the battery capability, similar like we did with solar, but -- so the orange line is the nameplate capability, and then the blue is the firm contribution at the time of summer peak.

You can see that in the earlier years, you know, they are matching almost 100, you know, one-for-one. And the more you start to add, similar to solar, you have, you know, penetration levels going up, then you have a little bit less contribution towards the summer peak. But both -- you know, they do show diminishing returns for firm contribution, but the batteries have different -- different uses. And they may not have been -- the members may choose to use them during different times for different purposes, not necessarily at peak, right? They may use them to respond to system disturbances. If they lose a unit, they may, you know, increase the output of the battery.

The batteries are slightly different in solar. The batteries need to be designed according to how they are going to be used. So the members would specify certain use of the battery, and then the

manufacturer would build it to that. So the ones that are being installed, and the members plan to use them for the peak, or available at peak are reflected on this chart.

Next we will turn to natural gas infrastructure.

So for years, the FRCC members have employed a consultant to maintain a comprehensive gas infrastructure model and utility fuels database. And this allows the members to identify periodic reliability studies examining different infrastructure contingencies, and perform studies to see if the expected infrastructure capacity is projected to be adequate. So based on these studies, the natural gas infrastructure capacity is on pace to support the planned generation additions.

On a realtime basis, as needed, due to system conditions, FRCC coordinates regional response to fuel emergencies with the utilities and pipelines. So the utilities in Florida have a large percent of gas generation with alternate fuel capability, which ranges between a 55 and 58 percent, which provides operational flexibility.

And -- and -- well, one thing that's pretty

unique in Florida is the natural gas is almost entirely dedicated to the electric industry in Florida. So in the winter, there is really not a lot of competition for the gas from other sources.

Next we will return to transmission adequacy and reliability.

So at the FRCC, and our members, we do -- we run significant amount of transmission studies to test the performance and adequacy of the transmission system. So we thought we would show -- share with you the types of scenarios that we look at.

So the scenarios involve peak loads, as you would expect for summer and winter. We also look at off-peak loads for summer conditions. And then we add about six other sensitivity scenarios to represent those 10 years out, or closer into the near terms. For example, we will look at a winter peak that's 20 percent higher than the forecasted peak that you have seen on the slides. We will also do a summer peak six percent higher than what you have seen on the slides.

We will do a summer peak high imports into the state. We will do an off-peak with solar at zero and solar at maximum. We will do another one that

will represent a clear sunny day, winter peak day in southern Florida. And we will do, say, a summer peak case with a couple large units unavailable, and solar at its maximum capacity.

Now, once we've built these scenarios with the models that we have, we test -- we test the system pretty rigorously. And basically we -- we follow the standards that are developed and approved by the North American Electric Reliability Corporation, which are then presented to the Federal Energy Regulatory Commission for final approval.

These reliability standards have performance requirements in them. And, you know, our members and ourselves, we are audited on these every -- every three years to make sure that we are following the standards.

And the standards basically test -- have us test every single element. So the loss of a single element, such as a generator, a line or a transformer, and then reviewing the results of that test. And we similarly will do an additional, where we take out a single element, and then we hit it -- we go ahead and outage another element. It could be another generator, another line or another

transformer, and then we review those results.

And the results of those -- all of that testing, and there is a few other tests that are done, have told us that existing and planned facilities within the FRCC region's transmission system meet the performance criteria that's contained in this NERC reliability standard, TPL-001-5.1.

The next couple of slides are related to FERC Order 1920, requirements that just came out. You know, the intent of this order is to drive interstate transmission expansion to access renewable energy.

This new FERC order will not impact the current order that's in place, the Order 1000 process that we have in place. That will remain.

The modifications of -- they modified in this order what they mean by long-term. So it's now 20 years into the future for transmission planning process, including, you know, Enhanced Transparency, and Right-Sizing and Interregional Transmission Coordination of Long-Term Transmission.

The investor-owned utilities must submit a plan to comply with this order by June of next

year. And the first study that's going to incorporate these requirements will begin by June of 2026, and then every five years thereafter.

And increase, Interregional Coordination allowing entities to propose new projects is what is expected. And these studies, as you might imagine, they are going to be extremely complex and will probably take up to three years to complete.

So some specifics on FERC Order 1920. It requires that we identify three distinct scenarios in addition to the base case, and we must consider an extreme weather sensitivity for each scenario. And then there is seven categories of factors to drive the development of transmission. And these -- the scenarios will be built addressing those factors. And I have listed those factors in a background slide, that's slide 29 included in your package, so you can see them, but there are seven factors. And that's going to drive, potentially drive identifying specific projects to meet those long-term needs established by these seven factors.

The projects will then be evaluated based on maximizing the seven benefits. And there is another slide and background information that just lists out the seven benefits on slide 30.

There will be two methods -- there are two methods for cost allocation of selected projects that commensurate with benefits. The -- there is one, the Ex Ante is the predetermined tariff approach, the cost allocation. And Ex Post, state agreement process for specific projects.

I know the FRCC and its members are willing to coordinate, collaborate with the State of Florida on this -- in this -- on this order when it comes to cost allocation.

And in conclusion, to summarize the aggregate Ten-Year Site Plans. Florida utilities continue to increase plant, solar and battery capacity installations with decreasing incapacity value attributed to solar as net peak shifts to later hours of the day.

Distributed, or customer-owned solar penetration noticeably decreases utility -- utility load forecasts.

Electric vehicle impact to load forecast is expected to increase substantially but still relatively small on a percent basis.

Planned reserve margins are above 20 percent for the 10 years.

Florida utilities continue to coordinate at

the FRCC to ensure reliability through studies of transmission system, natural gas infrastructure, solar and battery impacts to operational and planning.

And on this final slide here, the existing and planned transmission facilities within the FRCC transmission system meet the performance criteria for expected future conditions.

And with respect to FERC Order 1920, long-term planning horizon is -- will be 20 years. There will be seven categories of factors and seven benefits to consider.

Cost allocation will be commensurate with benefits. And this study will be conducted every five years, and must be completed within a three-year period.

And this concludes my presentation.

CHAIRMAN LA ROSA: So we will -- thank you for your presentation.

Commissioners, are there questions or thoughts?

Commissioner Fay, you are recognized.

COMMISSIONER FAY: Thank you, Mr. Chairman. And thank you, Mr. Ordax -- Ordax, correct?

MR. ORDAX: Yes.

COMMISSIONER FAY: Yeah, thank you for being here.

I just want to get first just some clarity of FRCC and the operation, just to make sure I understand how it aligns with the information.

So, obviously you intake the data from the utilities, and then input that data into various models that give you an idea, I guess, to oversimplify, of maybe things that work appropriately when needed to, or maybe where you would need to shift resources in a certain hypothetical circumstance, is that --

MR. ORDAX: So our transmission models are extremely detailed. So they will provide very accurate results as far transmission. So that would be for expansion transmission.

On the resources side. Yes, there -- and we do -- do probabilistic assessments that involve studying the entire 8,760 in the year, and so we do those at the FRCC in coordination with our members. So we use the same data that they provided; the capacity of all the units, their expected load forecast, and any sensitivities to those load forecasts and any average, say, forced outage rates of the -- of the units. And all of that is taken

in account in those resource adequacy assessments that are done.

COMMISSIONER FAY: Okay. And is that part, that information distributed to SERC, or I guess to NERC for review, or is that a -- like, I am aligning those two things. Are they -- are they the same?

MR. ORDAX: Yes. It is, and it's also included in the reliability assessment that was provided to -- to the Commission in the report. So there is a section there on reliability assessment and probabilistic assessment.

COMMISSIONER FAY: Okay. Great.

And then when you run those models, I am presuming some of the circumstances that you looked at were maybe you have an extra 20 percent needed for a certain time period, and I think you got a six-percent adjustment, so you run those scenarios.

Are there scenarios that raise the need for adjustments for the time being, or are those just so if a situation does occur, you are prepared to maybe advise on how resources could be reallocated?

MR. ORDAX: So the studies will show the times when the margins are at their tightest, and so there would be hours, say, maybe a couple of hours

in the winter, maybe during the winter peak, that may -- the program may say that we may be short in capacity. But when we get to those, like, specifically in the winter, the members do not plan to have any -- any generation outages, right? Their maintenance outages are -- are not allowed during that time. So they have all their fleet, except for the forced outage rates, available.

And they will have -- in operations, what they do is they will have -- you know, you expect a cold front coming, they will have operation calls on a daily basis coordinating with each other, and sharing resources if they have to if one of them is short?

COMMISSIONER FAY: Okay. And then in the real world application, FRCC provides notification to the Commission if there is a scenario where maybe a NERC requirement is met, is that correct?

MR. ORDAX: Yes. Yes. We do notify your staff when there is, like, a realtime issue happening. There has been a notification of an energy emergency alert, we let the Commission know as well, and so that's how we communicate.

COMMISSIONER FAY: Okay. Great.

And I know your -- your entity is going

through some transition with leadership. I think your -- your past CEO has stepped aside for the time being. But just for purposes of -- of understanding maybe how we fit into the -- the, you know, region and maybe the entire country, it appears, from my conversations with other commissions, that our reliability is some of the best. And I think that's probably the reality from what we see from our customers, and the utilities, and the information that's brought to us.

But do you have any thoughts maybe of beyond maybe the reserve margin? Is there -- is there a reason that -- you know, and Texas gets picked on all the time. They -- they are -- you know, since their first issue, and even recently, but they are not the only ones that deal with, you know, some of these issues of rolling blackouts, and -- and those challenges all over the country. So I know Commissioners ask me why is Florida, from a reliability perspective, even with the storms that we have.

Do you have -- do you communicate with other coordinating councils about their reliability, and maybe what we are doing that's different?

MR. ORDAX: Yeah, we do. We -- we are part,

we do sit, like for SERC, we do go to their meetings, and we share information at those meetings. And we are part of the NERC as well, and the Reliability Assessment Subcommittee does talk about these things, and a lot of those weaknesses are identified.

Our generation mix is different, right? We do have a lot of generation that we can rely on, you know, from natural gas to nuclear, even a little bit of coal. That we have control of, right? And we don't have control of the sun or the wind.

And fortunately, in Florida, we do not have wind, but these other areas are heavily loaded with solar and wind, and they have their own challenges, right? They -- they've expanded so quickly on that that they may not have prepared adequately.

And we're -- in Florida, we are going much slower, and we are integrating the resources at a pays that we feel is reliable. And, yeah, we do have -- our numbers are really good when you compare it to the rest of the nation, from reserve margins to even the probabl -- probabilistic assessments that we perform, we have very, very low numbers for expected uncertain energy, extremely low.

COMMISSIONER FAY: Yeah. Great.

Yeah, and to your point, it's so hard -- it's so difficult to implement at the -- the perfect speed, right? I mean, you want -- you want costs to come down. You want to make it worthwhile, but then when you bring this information forward, there is also recognition that we need to be thoughtful of the peak, and the adjustments in the peaks.

And so just real quick, last question. The aggregation creates a summer peak, I think, based on the information you provided. But it's my understanding, with some of our utilities, we will see variation between a summer and winter peak. Does that impact your -- your modeling at all?

MR. ORDAX: It's reflected in the modeling --

COMMISSIONER FAY: Okay.

MR. ORDAX: -- we take into account. Yes.

There is a very little diversity in the summer peak. But in the winters peak, there could be a lot of diversity between the members because of the region. If the cold front doesn't quite make it all the way, then we don't, maybe, get the loads we -- we could get.

So -- but all of that is reflected in our models. That's why we do -- look at seasonal

models on the transmission planning side, and then we do the entire 8,760 on the probabilistic side.

COMMISSIONER FAY: Okay. Great.

Yea, because I know it's, I think, since maybe '89 that we've seen that -- that winter impact, but it -- I think it's fair for just seeing what we have seen all over the country, with -- with some instability when -- when those things occurred to, you know, ask the question of how prepared are we with our reserves, and where would we be with some scenario that plays out. And it sounds like you -- you do the modeling for that. Maybe it's not identical, but at least gives you a general idea of some level of comfort for where we might be.

MR. ORDAX: Yeah. That's correct. We do have very healthy reserve margins. And then on the operations side, you know, there are also other NERC reliability standards that require weatherization of the units, right, based on your region. So the members are on top of that every year. They do review the status of their winterization to make sure the units are prepared for the upcoming winter.

COMMISSIONER FAY: That's great.

Yeah. And once again, I appreciate you

stepping up. I don't know if you drew the short straw, or anything, while that transition is occurring. I appreciate you coming in and giving us some information.

MR. ORDAX: Thank you. Appreciate it.

CHAIRMAN LA ROSA: Thank you.

Commissioners, other questions?

I have got -- I have got a few. I second the comments. Thank you for -- for presenting for us today.

So on slide 7, you talked a little bit about a few different things, but especially data centers. We are going to hear more in a coming Internal Affairs meeting about data centers and some things that we expect to kind of impact the economy, and so forth. And, of course, data centers are the talk of multiple industries, including ours, from a consumption perspective.

And I know you mentioned that the impact is unknown currently. But is there a methodology to kind of understand what this is going to look like in the future by looking at other states, or, you know, trying -- trying to get your arms around what you think data centers might --

MR. ORDAX: So we rely on our members to let

us know about that and reflect it in their forecasts. And so we know for this particular one, they -- they may be hearing rumblings about it, but nothing has really developed yet that they can feel comfortable putting into their load forecast.

I know that in the Virginia area, there is lots of it going on. I know PJM area, they've -- they've got thousands of megawatts that they are projecting for data centers and AI stuff.

But right now in Florida, we haven't seen it yet. I mean, obviously, I would expect some. So maybe the next year's Ten-Year Site Plan, we might see -- maybe the demand may show that a little bit, if -- if there are some solid plans.

CHAIRMAN LA ROSA: Understood.

On slide 15, kind of switching gears a little bit, when you talk about solar generation, the output. So you use this date of May 15th, showers coming across -- or a storm coming across the center of the state. I mean, that's -- to me, that's kind of a typical day. But what's -- what's the significance of this day, and is this kind of consistent in estimating, you know, a typical solar productive day in the state?

MR. ORDAX: So actually, no. This one we sort

of picked because it was easy to demonstrate the variability of solar, right, because we can't control the weather, and so that -- that's why it was picked. But we've got other -- there is many, many other days where the output is almost at the nameplate during the day, you know, during 1:00, 2:00, 3:00 in the afternoon. It's and it sits there solidly until the sun starts to come down.

So we just picked this -- this particular one on that slide to demonstrate the, you know, there is times that things are variable, and we do have to have other resources to account for that and be able to manage it.

CHAIRMAN LA ROSA: Well, I appreciate you adding the picture to it. That kind of makes it -- makes it a little more tangible.

MR. ORDAX: Yeah.

CHAIRMAN LA ROSA: And then last -- the last question for me.

On FERC 1920, do you feel that Florida could maybe be either absorbed to take on projects that maybe are not in the best interest of the state? And I know we are still trying to digest what 1920 maybe does or does not do over the last couple of months.

MR. ORDAX: Yeah, and one -- well, it depends if the -- the only one I can factor, since we are sort of peninsula, it's kind of hard for that to happen, but if something near the interface, near the Florida-Georgia border, if something shows up on their end that they might be interested in, and then they might want to coordinate with us and see if it's -- if it makes sense to come into it.

I -- I don't expect other, other than that, maybe inside Florida it would be -- in my opinion, it would be difficult because the members do a really good job at -- at planning that, identifying the best options. But, you know, you never know. I mean, we still have to go through the motions.

And the issue is, that you got those seven categories of factors that you have to consider when you build your cases, your models, and to study those. That might drive something that we haven't seen before.

CHAIRMAN LA ROSA: Does -- does that process change how you forecast?

MR. ORDAX: The forecasting of demand, and things like that, no. But what it will change is the things that we would have to meet. So if there is some federal goals that we have that would apply

in Florida, then we would have to model those goals, or how do we address those goals? And same, you know, state or local, you know, they went through the whole category of lists there.

You know, retirements, I know was on the list, but we always account for that. That was an easy one. But mostly, any, I guess, laws that get passed may impact what we have to consider in that arena.

CHAIRMAN LA ROSA: Awesome. Thank you. I appreciate you --

MR. ORDAX: Yeah.

CHAIRMAN LA ROSA: -- answering those.

Commissioners, any further questions?

Okay. Well, thank you for the presentation.

I will open up if there is any public comment. Is anyone here from the public that would like to comment?

Okay. Seeing none. I am going to throw it back to staff.

Any concluding matters?

MR. FAROOQI: I don't think we have anything else. We didn't receive any requests for public comment. But I will mention that we left the opportunity for written comments to stay open until

October 3rd. So once the public has seen this presentation, if they have any written comments, they can file it with the Clerk.

CHAIRMAN LA ROSA: Awesome. Well, thank you very much. Again, thank you very much for your presentation.

If there is no further business before us, I can say, I guess, that we are adjourned. Thank you.

(Proceedings concluded.)

CERTIFICATE OF REPORTER

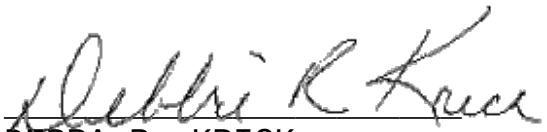
STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 16th day of September, 2024.



DEBRA R. KRICK
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