PLACE: Via Videoconference

DATE: Monday, April 12, 2021

TIME: 1:30 p.m. - 3:30 p.m.

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

IN THE MATTER OF:

PRESENTATION

E-100, Sub 101

Petition for Approval of Revisions to Generator Interconnection Standards

and

E-100, Sub 101B

Implementation of IEEE Standard 1547

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC and
DUKE ENERGY PROGRESS, LLC:
Jack Jirak, Esq.
Duke Energy Corporation
410 South Wilmington Street, NCRH 20
Raleigh, North Carolina 27601

Brett Breitschwerdt, Esq.
McGuireWoods LLP
$55001 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601
PRESENTERS: Anthony Williams and Philip Baker

FOR NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION:
Tim Dodge, Esq., Regulatory Counsel
3400 Sumner Boulevard
Raleigh, North Carolina 27616
PRESENTERS: Tony Eason and John Lemire

A P P E A R A N C E S Cont'd:

FOR VIRGINA POWER and LIGHT COMPANY, d/b/a
DOMINION ENERGY NORTH CAROLINA:
Andrea Kells, Esq., Associate
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601
PRESENTERS: Mike Nester and Mamadou Diong

FOR ELECTRICITIES OF NORTH CAROLINA, INC.:
Dan Higgins, Esq.
Burns Day & Presnell, P.A.
1427 Meadow Wood Boulevard
Raleigh, North Carolina 27604
PRESENTERS: Andy Fusco and Kathy Moyer

FOR THE CAROLINAS CLEAN ENERGY BUSINESS ALLIANCE:
John Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705
PRESENTER: John Gajda

A P P E A R A N C E S Cont'd:

FOR THE USING AND CONSUMING PUBLIC:

Robert Josey, Esq.

Public Staff - North Carolina Utilities Commission

4326 Mail Service Center

Raleigh, North Carolina 27699-4300

PRESENTERS: Dustin Metz and Tommy Williamson

P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon everyone. I now call to order Docket Number E-100, Sub 101B. We are here to take presentations from Duke as well as several other presenters on efforts thus far on the implementation of IEEE Standard 1547.

On June 14th, 2019, the Commission issued its Order Approving Revised Interconnection Standard and Requiring Reports and Testimony in Docket Number E-100, Sub 101 in which, among other things, the Commission required the electric utilities to host stakeholder meetings on IEEE Standard 1547 and to file a report with the Commission by April 1st, 2020.

On April 1st, 2020, Duke Energy Carolinas and Duke Energy Progress to which I will refer jointly as Duke filed the required report. North Carolina Clean Energy Business Alliance, now referred to as or known as Carolina Clean Energy Business Alliance, filed comments on that report.

On March 2nd, 2021, the Commission issued its Order Requiring Reports and Scheduling Presentation in which the Commission expressed the intent of the interest in staying informed of the IEEE Standard 1547 implementation efforts in North

Carolina. The Order also required Duke to annually file the most recent version of the Standard, its implementation guidelines, and a narrative explanation of any stakeholder meetings that have occurred since its previous filing.

The Order directed the Duke Utilities and DENC to make filings by March 15th in Docket Number E-100, Sub 101B. The Order also directed Duke to appear before the Commission to make a presentation to include a brief overview of the Standard; a discussion of the Standard provisions that Duke has prioritized in order to increase the amount of DER capacity that can interconnect with minimal feeder upgrades, and the status of implementing those provisions; discussion of the Standard provisions that would help secure the bulk power system by addressing DER ride-through capability and the status of those provisions; an overview of the IEEE Standard 1547 provisions that are anticipated to require any Commission decision making; and any recommendations that Duke might have for future stakeholder engagement efforts on these topics. The Order authorized NCCEBA, now CCEBA, the Public Staff, NCEMC, ElectriCities, and DENC to provide brief responsive comments at the presentation.

We're here to receive those presentations from the Duke Utilities, and following Duke's presentation, it's my understanding that we'll hear from CCEBA, and then from NCEMC. My understanding also is that representatives from ElectriCities, DENC, and the Public Staff are in attendance and are available to answer questions from the Commission should there be any.

In the interest of efficient use of time, we're going to limit questions to Commissioners only and not -- we will not take questions from the parties of one another.

Our court reporter is with us today creating a transcript that will be filed in the docket and available for your review on the Commission's website. We ask also that the presenters file their presentations in the docket specifically 101B as well.

As a reminder to our presenters, the Commissioners may ask you questions as you go along. As we are conducting this presentation remotely, I ask that you identify yourself before you start speaking, announcing your name, title, and party on whose behalf you are making presentation.

All right. In the interest of getting going

this afternoon, we will go ahead and begin with Duke. It's my understanding that Duke has three presenters this afternoon, so I'll ask those gentlemen to identify themselves for purposes of the record before they begin with their presentation.

Before I hand over the mic to Duke, I will pause here and see if counsel, you all have any questions for me.

MR. BREITSCHWERDT: Chair Mitchell, Brett Breitschwerdt on behalf of Duke Energy. One clarification. There's actually going to be two presenters on behalf of Duke, not three.

CHAIR MITCHELL: Okay. Perfect.

MR. BREITSCHWERDT: And then if I could, one second clarification. You had mentioned filing the presentations in 101B. Did you say the Commission is going to take that step or that you would like the parties to do so?

CHAIR MITCHELL: I would like -- I understand that the presentations have been made available to the Commission, but I'd like for you all to file them in the docket as well.

MR. BREITSCHWERDT: Not a problem. Thank you.

CHAIR MITCHELL: Mr. Breitschwerdt, I'll turn it over to your presenters.

MR. BREITSCHWERDT: Great.

CHAIR MITCHELL: Noting that there are only two of them.

MR. BREITSCHWERDT: All right. Anthony Williams and Philip Baker, if y'all would like to proceed. Anthony, you have the slide deck.

CHAIR MITCHELL: Mr. Williams, make sure you are off mute.

MR. WILLIAMS: Sorry about that. Can you see the presentation now?

CHAIR MITCHELL: We can, and we can hear you now, so please proceed.

MR. WILLIAMS: All right. Good afternoon. I'm Anthony Williams. I'm a Principal Engineer in Distributed Energy Technologies Technical Standards. For the last 30 years, I've performed power system analysis in a wide variety of areas. Right now, my focus is on distributed energy resources. I also lead the Technical Standards Review Group, the TSRG, and which we'll discuss that again a little bit later.

Philip Baker will join me later on the presentation, but first I'll begin with a general

discussion of Duke's implementation of IEEE Standard 1547-2018. I think Charlotte went over all these items. But recently the Commission asked us to give a brief overview of 1547 to discuss the implementation guidelines, how we prioritize them, and how we address the interconnection capacity and ride-through topics specifically. We'll conclude by providing comments on the status, Commission decisions, and stakeholder engagement.

EPRI shared a few slides and graphics with us, so we'll use some of those. I like this slide because it highlights the evolution from the 2003 version of the Standard up to the 2018 version. So 2003 established the unity power factor and the abnormal event tripping, so in those cases it shall not regulate, and it shall not trip. As a transmission planner, you know, such requirements are not really desirable, so as we move to 2014, the language changed over to "may" and allowed voltage regulation and active power ride through -- well, ride through for abnormal voltage. Then in 2018 they expanded on the details and the capabilities and now everything changed back to "shall", but they shall be capable of regulating riding through and capable of

frequency response. While the Standard is rather broad and has many different parts, this surveys the more critical parts.

So very quickly on the purpose of the Standard. It has two main parts I wanted to talk about; the Uniform Standard piece and then also the requirements. So in terms of a standard it's for an interconnection, it's not just about the capacity but also about uniformity across the DER equipment itself. So just making it, you know, a more standard device and easier to understand what's there. The interoperability piece, a little bit of a strange word to me but I think of it just in terms of SCADA, so and that's the control and the data that's shared between the Utility and the DER.

In terms of requirements, and I see this more as a functional standardization, each device, each manufacturer they're free to design their functions differently, but what the device does it's essentially the same, you know, in terms of that particular function. So in this presentation our attention will be mainly on the functionality or the performance piece. There are the other sections that are mentioned here in the requirement section like

testing and interoperability, but today we're not specifically going to focus on those.

1547 is for distribution connected DER only. It's not transmission connected. Those have their own standards and requirements. The focus is on DER requirements in terms of, you know, more of an equipment standard, not so much on utility requirements. It's still focused mainly at the DER. And then it also expands on the interface between the power system and the DER itself in terms of the power system connections and the communication connections at the interface.

So as we talked about it's about performance of the inverter, not how to design it, or about the functions, not the utilization. And there's at least eight main technical sections with many requirements in each section. And then towards the end of 1547 there's two other large sections for nesting and interoperability.

And a little bit of a final point, but we tend to still call the Standard 1547-2018 although there is a small revision in 2020 for category 3 ride through. We still just generally say 1547-2018.

The Commission specifically asked about

interconnection capacity, and voltage regulation is one of the few functions that could impact that. This slide is an EPRI slide and so they've highlighted a couple of words here and they note that the Standard requires capability in the DER, but the Standard does not require that the function be used. So again, just focusing on the equipment side of things.

So although the table is a little bit busy it comes right out of the Standard, but I wanted to call your attention to the right-hand column for category B which indicates that all the voltage regulation functions are mandatory with that classification of control. So at the top of the table there are four reactive power controls. And so two, inject or absorb reactive power, that does require some of the ABA capability. So in some cases, depending on how the equipment or facility is designed, that can impact the overall active power generation where the last controller is active power control, and you would not expect that to impact the ABA capability.

The last bullet is about applications. Many times with voltage and reactive power control, your uses for interconnection which would be like the

initial connection to the power system and also grid support providing, you know, voltage or reactive control support. So right now Duke is mainly focused on the interconnection piece and not grid support right now.

A good bit of effort is put into clarifying tripping for events and capability to ride through in the Standard. These are the sections that -- two of the main sections here, 641 involves tripping, and then the second requirement focuses on the capability of the DER to operate until it trips. So, you know, whenever there is an event, the capability portion of the requirement keeps the inverter in service and provides time for protection systems and other controls to mitigate the event. If the event persists, then the tripping occurs.

So the tripping requirement as we discuss, it's always been here, but more emphasis has been placed on the capability to ride-through disturbances and also for longer periods of time. So if we put these two together, then the capability allows the inverter to continue to operate or ride through until the trip times are reached.

Since mid-2019, Duke has been considering

how to apply the Standard. The first discussion of that was around May 2019, the TSRG meeting, and the discussion there was around providing, you know, some type of guideline document to decide how we're going to implement the Standard.

So overall the -- so as a quick review, just real quick on the TSRG. So again, we said that's the Technical Standards Review Group. So Duke and the DER stakeholders meet quarterly to discuss the technical standards for interconnection, with the distributed energy resources, to both systems in, you know, North and South Carolina.

Soon after that May meeting, the Commission also requested the guidelines be filed, so we did file that original version back in '18 -- April of 2020 and that's the table of contents, this here on the right-hand side. There's 26 different topics in that version of the Standard or the guidelines.

But below, I want to talk a little bit about this graphic from EPRI. We use it to just talk about the structure that was kind of standing behind the guidelines that we're developing. So the blue layer at the bottom is just the basic standard as it's adopted and with the default values, so you're just

taking in as it is. The next level up is the regional level for RTOs, ISO requirements or specific settings that they may have which will not be an issue for Duke. And then the yellow layer is the utility-specific guidelines that take into account how the system is designed and operated and, you know, many utilities have some specific requirements in this area just to address, you know, their unique systems. The top of the pyramid indicates that there could be some specific requirements, you know, just to unique or one site and this is kind of the crossover point from utility guidelines to specific DER settings.

So our guidelines are structured somewhat this way. We prefer to focus mainly on the Standard as it's written and the default values that are there and try to adhere to those, try to keep it simple and follow the guidelines there.

But then as we need to, up in the yellow layer, you know, there are some places in the Standard where they require the Utility to specify settings or other requirements, so in those areas and then we'll be adding, you know, our own specific language to the guidelines. But we're trying not to just repeat everything that's in the IEEE Standard in our

guidelines. That way when you come to the guidelines, it's really about the things that are going on with Duke.

Concerning prioritization of the items that are in our guidelines, we've considered many different factors. We've highlighted those here. Starting at the top is just the different items that impact grid support. The main document there is the NERC reliability guideline. There's also been some similar guidelines put out by other RTOs, ISOs, so we considered those in selecting our priorities as well.

We also looked at the functions that are in 1547, specifically those that could directly increase the amount of DER interconnections, and really these three stand out in that sense: Limiting active power, voltage and reactive power control, and voltage and active power control.

Of course, through the TSRG we took stakeholder comments. We polled the group on what was important to them. And then we also looked at implementation plan reviews from other utilities to see how they were prioritizing the various items.

And because there are so many topics, we looked at the high, medium, and low priority, but also

the complexity of resolving the technical issues, or utility scale DER, and that's what's in the graphic here on the right-hand side. The technical parts of the Standard kind of range from complex to detailed to even basic, so the amount of effort to understand the topic and decide how to implement it varies. It can vary a good deal.

Then the high, medium, and low just expresses, you know, kind of the value of that requirement itself. So we tried to minimize how many complex topics are being addressed at one time just to kind of allow the right focus on the topics. So considering all these bullets above, a priority order was set following the April 2020 TSRG meeting.

And so those priorities can be summarized like this. There's basically five. So the first one is about reactive power and voltage control; second for ride through; and then three, four, and five more or less divide things out between high, medium, and low priority of the remaining items. They're not all in section four, but that's the general idea of the structure that's in the guidelines.

So to address reactive power specifically, the current state at Duke, you know, we only use

constant power factor right now and the default is unity power factor. The first study which was filed with the Commission April of 2020 was performed by Navigant and the focus there was how well reactive power control even worked at the various locations along the feeder looking at locations close to the feeder head, middle of the feeder, end of the feeder, that type of thing.

We also considered how well a universal setting might work for all utility scale DER. At this point, you know, we weren't very sure how complex the whole question was, and the analysis, and could one universal setting work at those three locations - head, middle, and end - or would it be kind of a case-by-case study for each individual site. We wanted to get a better idea of that. Also, with that study we were able to affirm that Category B was the normal performance requirement that we would like to use. But that first day it left a lot of questions as well, so we talked about it in the TSRG, and we commissioned a second study. EPRI is working on that study now, and it would focus on a time series analysis.

So the first study was performed more

similar to just a traditional power-flow study where you have one load condition and one generation condition, such as minimum load at peak generation. Whereas in the second study, we considered different load levels throughout the day, hour by hour. So basically there's one study each hour from min load to peak load, and then we considered the corresponding output from the DER for those same hours. So many more analyses in the second study.

Then we considered the impact, and we evaluated the interaction between the existing voltage control devices and the DER that it would have, the reactive power control. So in the first study since it's a fixed-load case, it was easier to set any devices that are on the feeder as they should be for that load condition. Those devices might be load tap changers, voltage regulators, capacitors, but when you start sequencing throughout the hours of the day with various load levels, all those devices may change -- you know, have the potential to change state, so we had to model that and include that in the study as well, and that study should be wrapping here in the next couple of weeks.

So during this time we've also committed to

some pilots with a few facilities for reactive power. And then following the second study with EPRI and discussions in the TSRG meetings, we'll determine what the next steps are in terms of studies and for reactive power.

So next I'd like to turn it over to Philip and he'll discuss the protection settings and ride through.

MR. BAKER: Thank you, Anthony. My name is Philip Baker. I've worked at Duke Energy for 33 years. I'm currently a Principal Engineer in the Transmission System Standards Group. I'm going to talk specifically about protection settings for ride through, so it's a continuation of some of the topics Anthony has introduced and I've got about three slides, and it'll go back to Anthony in a moment.

I want to call specific attention to the first half of the IEEE definition for ride through. And that is the ability to withstand voltage or frequency disturbances inside defined limits. I think Anthony mentioned on a prior slide that there are three categories for this, and they have overlap, so given a certain setting it may exist in all three categories. The time delay may exist in all three

categories. It just depends on the settings that you've selected. There's a lot of latitude in each category. As the categories increase, the guard rails widen I should say, be a good way to say that. But it's up to the Utility to pick the settings that -- that actually work.

And system protection, it's a very broad topic. People spend their careers dealing with just this subject, but I wanted to mention three key objectives that relate to the selecting of the settings. These three objectives are ride through bulk electric system faults to prevent unnecessary tripping of the ER. Second bullet is trip for faults in protection zones where tripping is required. And the third one is trip for unintentional islands. It boils down to avoid unnecessary tripping but yet trip when required and that's the -- turns out that's a fairly difficult thing to achieve.

Adopting protection settings that exclusively emphasize one objective may compromise one of the other objectives. So a balanced approach is needed, and research is needed to optimize these settings for the best performance.

So next slide, Anthony.

Okay. Research plan focus areas. I want to highlight a couple of focus areas and then some things about how we're implementing that.

Settings optimization, this is research directly targeting the balancing of the three objectives on the prior slide as well as other things. This optimization does include mitigation for any known past event or predicted events. The Commission had specifically asked about a BES event that we had where a lot of DERs tripped. This event is included in that research proposal.

And then there's coordination of settings with the DER settings. So at sites typically bigger than a megawatt, Duke has a protection device installed at the site so the settings in the Duke devices have to coordinate with the settings in the DER facility whether that be onboard settings or flat level settings, and that's going to require a good bit of stakeholder engagement as we go through this coordination exercise.

So how are we implementing our research plan? There are three main areas. One is consultant based. This is our most comprehensive research area to look at all aspects that Duke is interested in to

try to optimize the protection settings. There's the EPRI IPRAT project which is the Islanding Preventing Risk Assessment Tool. That's an important piece to help quantify risk associated with one of the key points that was mentioned. And then there's a CAPER project. This is a consortium of universities and some industry. It does include NC State, UNCC, and Clemson. And the main avenue of research here is combining the transmission and distribution studies together to validate the proposed, the ride-through settings.

Next slide, Anthony.

All right. Apply settings. So once we know what the settings are, we have to -- we have to put them to use, so in other words what does it take to put boots on this thing and make it work. Two areas to mention here; in-service sites and new sites.

For in-service sites, we are mainly focused on sites at 1 MW and above. Those are the sites that typically have a utility recloser, so we do have to visit those sites and put new settings in them. And then we have to find out what is the ability of the in-service DER equipment to accommodate new settings. One way to do that may be to look at the old 2003

Standards and see are our optimized settings, do they fall within the bandwidth of the requirements from that era. If they do, then it's almost certain that these devices will be able to accommodate the settings. It may need a survey to find out what the setting abilities are, and then we have to change settings in those sites. So that's the summary of the in-service work.

For new sites, it's a couple of bullets here, but in summary the new optimized settings we come up with, the goal is to have one set of settings that works across the board, so this will be for any new site regardless of size. Again, the sizes of megawatt and above would likely still have a Duke recloser, so -- but these should get -- the hope is that these will get the same settings that we develop for the in-service sites. We see no reason to have different settings at this time, but the research will reveal that if there is a necessity to have different settings for new sites, but the hope is that they'll all be the same.

So that summarizes and ties up my protection settings slides. I'll hand it back over to Anthony.

MR. WILLIAMS: All right. Thank you,

Philip. So to summarize the implementation activities, we've established the priority order to focus on the most relevant sections of the Standard. We've issued the 1547 guidelines and revised them three times since March 2020, and we should have the fourth revision out for this TSRG meeting at the end of the month. We've discussed the guidelines in at least five meetings so far. And we've finalized the proposed technical testing and interoperability requirements on 11 of the 26 prioritized sections of 1547. And then there's several sections in there that aren't quite finalized, but, you know, they're in various levels of completion.

And then we will be soon completed with the two reactive power studies between November of '19 and April of '21, and we have those reactive power pilots planned. And then Duke plans to discuss the schedule and timeline at TSRG meetings later this year.

In terms of Commission decisions, there are not really any known decisions at this time, but I think they talked about anticipated so it's possible there could be some, so we've listed a few areas here. With new Interconnection Agreements, should we go forward with the reactive power capabilities, you

know, since unity with default-to-power factor has been what we've had so far, there's not much in the agreements about reactive power, so there would probably need to be some additions there.

And then we just wanted to review and make sure that we have the right references to 1547 or if there's any specific requirements that need to be added or included there as well.

Then for the North Carolina Interconnection Procedures, it's possible that there would need to be an adjustment for additional data to support new studies and new inverter functions. Everything in there now is not focused on the smart inverters.

And then qualifications and clarifications about the grounding issues. There's a few different sections in the Standard about grounding and that's been something we've been trying to address in the NCIP anyway.

And then there could be some changes with Section 3 Fast Track and Supplemental Review. Again, the thoughts are kind of around reactive, you know, if we can develop some way to screen or some basic supplemental reviews that may help address, you know, moving those projects through the queue or identifying

the right ones that need system impact studies. And then again, just making sure the right references are there for 1547.

Method of Service Guidelines is included. That's the interconnection guidelines that Duke has now. So the 1547 Implementation Guidelines is a separate standalone document that's just about the technical issues with the new version of 1547, implementing those guidelines, testing interoperability; all those things are in the guidelines. So as those things are finalized, we may want to move some of those over to the Method of Service Guidelines. So there's the potential to have changes there.

And so Duke will continue with stakeholder input and continue to identify and evaluate anything that we think needs Commission decisions.

In terms of stakeholder engagement, that's been part and parcel to the process from the start. So the first time we addressed this was a January 2020 meeting, and been determining how to address the 1547 implementation, and the TSRG decided then to continue to address it in the quarterly meetings. We've had multiple meetings since that time, so we discussed

mainly the changes that's happened in the guidelines since the last revision. We had a discussion on those topics, but that's just at the meeting time, you know, we really have like open door where people can submit comments any time they would like. You know, so we encourage comments even outside the meetings. And the TSRG has been effective so far, so we plan to continue to use that as the forum for implementing this and for discussing all the issues.

Just a little bit more on the TSRG. There is a public website and the address is listed here at the top of the slide. And so on the -- there's a screenshot on the right of the web page and you'll find references to technical standards, commissioning documents, meeting information. And then on the left side of the page, I kind of expanded one of the more recent meetings where you can see all the documents that are provided there; agendas, presentations, any documents that we discuss during the meeting.

So in summary, we'll keep developing the guidelines with the TSRG, those three areas that we've been talking about. We'll complete the necessary studies. And we'll define any of the Interconnection Agreement or other process changes that we need to do

and that includes Duke internal process changes. And we'll continue to work on the schedule and timeline, and then we'll go back and pick up the lower priority 1547 items and address those as well.

So that's the conclusion of the presentation that we have for Duke Energy. Thanks.

CHAIR MITCHELL: All right. Thank you, Mr. Williams and Mr. Baker. I do have a few questions for you and I'll just sort of direct them your way and you all can handle them as it is appropriate.

And I'll preface this by saying y'all have to remember I'm an attorney by training, not an engineer, so some of my questions are going to display my ignorance of the engineering in that regard. But so the -- is it the case that the Standards encapsulated by 1547-2018 can be applied to any inverter? Or are there only a certain generation of inverters that can be set to 1547-2018 in its, you know, in going forward? And the reason I ask that is this, I mean, you know, are we looking at going back and recalibrating a bunch of inverters existing on the system now or are we looking only at making these types of changes in these types of settings on inverters as they come on going forward or inverters

that have not even yet been developed? Does that -- does my question make sense?

MR. WILLIAMS: Yes. I think so.

CHAIR MITCHELL: Okay. Go ahead.

MR. WILLIAMS: So to take the first part of the question, so can you -- what's the Standard really directed towards? So I think it's really directed towards what we classify as new inverters, so UL is working on a standard for testing. They completed the Standard, but the manufacturers have to submit the inverters that they have to go through the UL testing, and then they would be certified to the 2018 version of the Standard. And so coming out of that testing, you'd know that you could apply settings from the Standard that all those inverters would have the functions that are required by the Standard and you'd be able to go forward.

So, you know, it's possible for -- if we go back to the very beginning and we look at the EPRI slide about the evolution, you know, in 2014 there were some inverters that may regulate voltage, may ride through, so there are some functions of older inverters that maybe you could apply some of the same settings from 2018, but I think you would just have to

take a hard look at that to really make sure they had that capability. They may or may not.

Some other people maybe have already crossed that bridge and may know more about it, but, you know, our focus is more on applying the 2018 version of Standard to inverters that have been certified to that Standard.

CHAIR MITCHELL: Okay. That makes sense. I appreciate that clarification. That's helpful to me.

In part of your presentation you discussed changes that you all envision to the North Carolina Interconnection Procedures primarily as I recall pertaining to the reactive power setting. So help me understand, I mean, are you all envisioning a scenario where an interconnected facility is providing reactive power to the system or otherwise sort of absorbing reactive power such that it's providing a service to the system that it would get paid for?

MR. WILLIAMS: Right. So right now we are not. On this slide, the very last bullet I was talking about grid support functions, so right now we're not considering those which would be, for lack of a better term, you know, assisting Duke with maintaining voltage on the system. We're focusing

more on the interconnection piece where you would use that functionality to help maintain voltage just for the interconnection of the DER.

So, many times because the DER, the inverter is injecting active power that causes voltage to rise, and that can create a voltage violation. So if they absorb reactive power, that brings the voltage down. So then that may remove the violation, so then they don't have a violation for interconnection.

So that's how we're using it, you know, in terms of the interconnection, but not so much as hey, we just want to maintain 124 volts on the system, so you regulate the voltage. You know, that would be more grid support and we're not looking at that piece right now.

CHAIR MITCHELL: Okay. Thank you for that. I appreciate that clarification. That helps me as well.

All right. I'll pause here and see if any other Commissioners have questions for the Duke presenters before we turn them loose.

(Pause).

Okay. I'm not seeing -- I'm not seeing anyone else's hand up. So, with that, I appreciate

your presentation this afternoon, Mr. Baker and Mr. Williams. And we look forward to staying informed of y'all's progress in implementing this Standard.

MR. WILLIAMS: All right. Thank you.

CHAIR MITCHELL: We will hear next from CCEBA. And I think Mr. Gajda you are up to present on behalf of CCEBA.

MR. BURNS: Madam Chair, this is John Burns. I'm counsel for CCEBA. I appreciate the opportunity to appear before you for my first time today. You are correct. John Gajda will be doing our presentation. He has prepared some slides and is in control of his slide deck, so I will turn it over to him.

CHAIR MITCHELL: All right. Thank you, Mr. Burns.

MR. BURNS: Yes, ma'am.

CHAIR MITCHELL: And good afternoon, Mr. Gajda. Good to see you again.

MR. GAJDA: Yes. Yes. Good to see you all. Hopefully, you've got my screen there and you can see it and you can hear me all right?

CHAIR MITCHELL: We can hear you and we can see your slides, so you may proceed.

MR. GAJDA: Fantastic. Well, to all of the

Commissioners, thank so much for the opportunity to speak to you today. And we just wanted to provide a kind of perspective from the Carolina Clean Energy Business Association. Again, my name is John Gajda. I'm Principal Engineer with Strata Clean Energy of course here representing CCEBA.

So just a little perspective, and I expected and that, of course, Duke would, you know, give an overview, so what we've done here is really just try to focus our comments not so much on the overview which Duke has well provided, but these are kind of where we wanted to focus our kind of some points to just, you know, give some other perspective, you know, give a reference to some adoption status across the US. I'm not really going to spend time on that, but I've provided that, and we can talk about if there's any questions but I included that here at the end of the presentation.

I thought it was useful and I think Duke did a pretty good job of this, but to really understand 1547 stakeholders, it is a very technical standard and I kind of actually tried to draw a little comparison to electric vehicle plug standards. I don't profess to be an EV expert, but I think this will work for

everyone.

There's been some comments in the filings about TSRG engagement and I wanted to address that, because I think that's really important. TSRG has been a valuable entity to have, so I wanted to talk about that. And then just kind of a calibration on, you know, so where are we. And then I think an interesting little example from the Massachusetts TSRG, and then just really what success looks like for us.

And this is, again, just a reference slide I've provided in the appendix. This is publicly available. It's from the IEEE Standards Association and EPRI and they really provided just a small number of slides on adoption status across the US. It felt like it was really good to put here for everybody to reference and -- but I think for the sake of the Commission I'm not going to present those.

So let's dig into talking just a little bit about understanding 1547's stakeholders and how do standards help us. And I thought actually this comparison to EV standards was kind of maybe interesting. And again, I don't profess to be an EV expert. But if you look across the middle of the page

you see I kind of draw a linkage here. You have EV manufacturers. You have DER equipment manufacturers like inverter manufacturers. So anybody who has purchased an EV, okay, you're a purchaser or an operator, you might be kind of similar to a developer or an operator of a renewable generation site.

Deploying charging stations across, you know, some kind of area is kind of the other piece of that, and you might draw a linkage to utility equipment manufacturers and utilities. And then in both cases we've heard it's the public and the environment is a stakeholder.

So where I draw this, too, is an interesting question which is who cares about the plug itself versus what a standard plug actually provides. Many of you have seen an EV or have seen an EV plug. It's got a certain number of prongs on it. And a lot of engineers can get together and talk about how many prongs should be on that plug. Now, that's important to people like Tesla or Chevrolet or Nissan or people like that. It's also very important if you're a manufacturer of a charging station or you're developing charging stations and putting them out there. But ultimately what you really care about is

that those match. And you don't really care about how many pins there are. That might be a General Motors or a Tesla thing.

I mention this because this may tell us a little about which stakeholders will really be engaged and how they will be engaged. And I want to revisit that in a second.

So I think Duke mentioned this a little bit, but I think Anthony did but, you know, technical standards are to make everything the same which is to reduce cost for the whole value chain and all the stakeholders here. So we very much view plug standards as spurring the adoption of EVs. If they all had different plugs, you know, that wouldn't be good for adoption.

Kind of similar with 1547. It standardizes the equipment. I think the key element to enable success on the EV side is you could have a whole bunch of cars with the same plug, but if you talk about a charging network and if it's not really there or it doesn't really develop or expand, then you perhaps don't reap the value of that.

And in this case you're going to hear me mention a couple of times the Utility what I call T&D

planning and operating standards, which is really a level above or different than 1547 itself. And I think there is a reference to the fact that 1547 is a standard for the equipment or for the facility but the Utility may or may not end up really implementing that part of the Standard in such a way that the equipment can, you know, fully utilize its capabilities.

So a quick couple of comments about the TSRG and kind of engagement from both of the parties. I think there was a very valid concern. Duke mentioned once or twice a little concern I think, if that's a valid term here, for engagement of the DER stakeholders. I think there is -- I wanted to take this opportunity to highlight why I think that is.

Two big things, I think. Much of 1547's requirements are impacting right now, before everything is available, they're impacting equipment manufacturers. DER engineers, engineers, say developers and such organizations, can't even really yet specify nor purchase this equipment.

It's also well known that DER equipment manufacturers like inverter manufacturers have struggled for years with robust product documentation and understanding grid requirements and how utilities

approach such requirements. And that's just been a weakness on the equipment manufacturer's side which is getting better over time. So when folks show up at the TSRG meetings from various developers, they're very aware of what's happening with 2018, mostly thankful to Duke, but also outside of Duke because a lot of them are engaged in the 1547 Standards process.

That being said, it's very important to figure out how many pins are in an EV plug; however, the DER side of the house may mostly be worried about, you know, the Standard being effectively carried out as opposed to worrying are there four or five pins in that plug. So that could explain really a little bit about why, you know, you may not have -- like Duke isn't necessarily seeing a lot of, you know, questions or say criticism from the DER side and the TSRG.

And the other piece is just a reality which is very, very -- you know, I'm personally very aware of this just through my background, DER engineers are not transmission and distribution experts and I think nobody should expect them to be. There is a heavy reliance on the Utility to move ahead with changes to its what I call again planning and operating standards to be compatible with 1547. So, you know, we heard

from Anthony and Philip and, you know, there's a lot of technical content you see that they presented, and so the DER industry is definitely relying upon that.

The piece that where we're just not at yet that is to be talked about is once these application guidelines are fully developed, developed out, where will the -- will there be any changes to planning and operating standards that then allow say, for example, voltage regulation capability to be more fully used. If those changes happen, and then there's more -- there's clear requirements for DER developers, that will allow for increased DER development and penetration.

I think the Utilities, and I think this is not really a critique or a criticism of the Utilities, this is an acknowledgment of where we're at and with where utilities sit when they come to a TSRG, but it's kind of three main points here. If utilities are not incentivized to maximize DER penetration, and I'm not really here to say if they should or not be, but if they aren't, then there's not really a lit fire to move ahead with altering the Utility side of, you know, again, the planning and operating standards. There's really not a, you know, fire to move that

piece ahead. They can go ahead and clarify the existing 1547 and, you know, every one of its individual little detailed pieces and how that might work with their system, but the Utility is clearly, and this is stated everywhere, is not under an obligation to advance the use of those in a broader sense.

So why do I keep kind of talking about this operating and planning standards thing? Well again, the active control requirements that 1547 enables, and I think that's a great term is "1547 enables", these capabilities and it enables voltage control, reactive power control, active power control, these are some of the things Anthony talked about, 1547 enables this, but you can't really -- but the other piece of it has to happen. If there are no changes really considered to the say planning and operating standards, then we all know we're operating with unchanged distribution system architecture. And I'm just kind of really throwing this out here to really say that, you know, this needs to be a transparent piece of all of this.

Without guidance which encourages things like new voltage regulation schemes or, you know, different polices on multi-circuit feeders, there

could be a number of things, things like new inverter regulation or voltage regulation capabilities, risk being used in isolated situations only. So that's important to note.

I'm not -- Duke's engagement on abnormal conditions requirements which are really kind of the ride-through piece of this, this has been an ongoing topic in the TSRG. But actually, I was really excited to see the update from Duke today because this actually -- we haven't seen a comprehensive update in the TSRG on the ride through piece in the last few meetings, so seeing Duke's presentation today I would almost retract a few of these comments. It looks like they are making some decent progress.

There are ISOs and RTOs across the country which have moved ahead already with developing guidelines for voltage and frequency settings. I know Duke would be aware of this through their involvement with PJM and MISO outside of North Carolina. So I just mention that the DER industry is really ready to engage on that piece. This piece will impact to some degree, could impact existing sites even though existing inverters don't even -- weren't built to the 2018 Standard. There is a connection to those, and I

think Philip actually referenced that. So we look forward to really just engaging with them deeper on that. That's really -- that has to be initiated by them because it's all about grid reliability.

So just kind of where are we now? I think, you know, Duke's efforts to date are all in the right direction. So I think, you know, at CCEBA we really want to acknowledge that. The VOLT/VAR studies, this is in my time in this business, this is exactly what I envisioned would first need done to figure out how inverters could be used on the distribution system with these enhanced capabilities. The creation of the application guidelines, yep, also very much in the right direction. So again, this is why CCEBA's filing we didn't really highlight that. You know, we felt like it was moving in the right direction here and -- you know, and they are.

We do think there might be some under estimation with volume and complexity to come. We made some comments in filings about the idea of possibly kicking off a subcommittee in the TSRG, which has been done in other places to specifically address 1547. And, you know, I think our only point there is really to highlight the need to be able to dig into

the volume and complexity, and if we can do that in the regular TSRG, then great. But if other topics kind of come in there, you know, I think it's going to be important to have the bandwidth and the time to address that.

I think there is a need to move, and this is another update that Duke gave today which I was really glad to see, was the idea of moving some 1547 guidelines into the Method of Service Guidelines, which sounds to me, I don't want to over interpret that, but sounds to me like a move to a comprehensive requirements manual. That would be highly valuable I think for all stakeholders to have a comprehensive DER requirements manual.

You know, this is something really that could be -- that could be started, you know, fairly soon. Existing requirements documents are in a few different places so comprehensive manuals like this minimize controversy, they provide predictability for everybody, but, you know, that's a great thing we look forward to talking with Duke about. And the DER industry agrees its personnel needs to be ready to listen and engage as Duke drafts specific requirements.

You know, necessity is the mother of invention as they say, so when we see these application guidelines and they address grounding or various things, I can see -- at the meetings I can see where some of the DER side might -- it might look like the engagement isn't there. I think they are in a serious listening mode, because in some cases Duke is clarifying things that need clarified and -- but they may not actually immediately impact anything on the -- you know from a standpoint of how the DER site might build a site. So in that case there may not be a lot of feedback in some cases.

So there likely will be I think in the future more than one way to skin the cat as they say, more than one way for a DER design to meet certain requirements, and that will be the important time to have the two-way conversations in the TSRG.

You know, I don't believe every state needs to do things the same. I personally visited the Massachusetts' TSRG once, and I bring it up not just because they formed a TSRG subcommittee, but I bring it up because the exact meeting that I happened to attend in November of 2017 there was a really unique kind of little situation which occurred which I think

highlights the value of a TSRG in this situation and I think it's just great for I think hopefully for all the Commissioners to hear this.

I happened to be sitting in this meeting and it was the New York ISO that was bringing concerns to the Massachusetts Utilities about these ride-through settings. And what was fascinating was everybody -- a few prior meetings everybody had already talked about this, but the rubber was getting ready to hit the road and they really wanted this to start happening and they told the distribution utilities you need to start talking to your interconnection customers about implementing this. We're in the inverters. You know, in -- somebody programming the exact frequency setting.

And in the space of that meeting what they determined was that if these settings got individually keyed in, it was going to be very error prone and that inverter technicians individually keying in settings did not somehow sound like a great plan. And when they got the right inverter manufacturer on the phone and they got to talking, what they realized is they said hey, wait a minute, if -- and this was kind of a comment back to the ISO, said if you guys, if there's

any way you guys can put off your requirement date by just a little bit, we can encourage the appropriate inverter manufacturers to put a settings profile in their inverter. And what that means is is essentially then you just tell an inverter technician who, of any kind of inverter size we're talking about here, central station, residential, you tell the technician, he goes in there with his laptop and he selects the New York ISO profile and that's a simple pull down. And it highly removed kind of the error-prone nature of what was being talked about which was specifically keying in settings.

What was fascinating to me in watching this kind of 45 to 60-minute discussion was that as a group they arrived at a whole new solution that it seemed like nobody would've really gotten to without that kind of discussion. So I hope that's valuable to you. I look forward to those kind of things occurring in the TSRG here. And we may just not be there yet just because of where we're at but I look forward to those.

So just to kind of summarize, I think success from the Utility and then the DER side, I think a Utility commitment, I think this idea of a comprehensive DER requirements manual should really be

looked at. It'll be really valuable. I think when available, the DER industry is really interested in getting the clear requirements from the Utility on the required inverter and relay settings for abnormal conditions requirements, the ride-through settings.

This will involve cooperation of DER developers and operators. Philip referenced this. And I think there will be a discussion in the TSRG on, you know, what's feasible and how and when. How do we carry it out? So we look forward to that.

I think transparency around this concept of planning and operating standards, you know, the Standard is an EV plug standard in a sense. Will there be any changes to planning and operating standards to enable the use of the new plug standard? And this could very well -- there's a whole proceeding around ISOP, Integrated Systems Operations and Planning; this could very well have a connection to this, but I think that's a separate discussion.

And further developing out any, you know, TSRG structure, I think CCEBA is wide open on what that structure can be just to meet what needs done, the agreed-upon needs and goals.

Finally, the DER industry needs to commit to

engagement in, you know, in practical discussions. And I think the commitment is there. I think it's just going to have to continue to increase. And one of the things that I know the industry, and I know from speaking with Strata, the industry is looking at is is really ramping up its critical grid control equipment, which is mostly inverters and a few other devices; just really ramping up its ability to track those assets, manage those settings. This is something the Utilities have done for years with relays, manage settings at every substation on the system. Well, you know, now this is where DER owners and operators are at and so this is a big piece that we are ramping up with right now. And again, another commitment to developing out the TSRG structure.

So I hope that's helpful. I think that all that's left on my slides are the information about adoption across the country which I'll just leave if anybody wants to look at.

Commissioner Mitchell, I hope that was -- I hope that's helpful.

CHAIR MITCHELL: It was. And Mr. Gajda, it looks like we may have just -- I lost video connection with you. I hope you can still -- oh, there you are.

I do have a couple of questions for you. First, I'm looking at your slide number nine and you make the point further develop TSRG structure to meet agreed-upon needs and goals; so --

MR. GAJDA: Yes.

CHAIR MITCHELL: -- help me understand, sort of start at the beginning here. The TSRG is a group that convenes on a regular basis and discusses technical issues, a subset of which have been implementation of 1547 sub -- I mean, 1547-2018?

MR. GAJDA: That's correct.

CHAIR MITCHELL: How much of the TSRG's time has been allocated to this topic?

MR. GAJDA: The meetings especially, and Anthony will correct me if I'm wrong, but the -- they've been roughly half-day meetings during COVID for about the last year, and there's been generally around three topics. So I would say it was -- it's been an hour to an hour and a half of the four-plus hour TSRG meeting has been usually Duke's 1547 update in those meetings.

CHAIR MITCHELL: In your opinion how much time should have been devoted or should be devoted going forward to this topic?

MR. GAJDA: I think it's up for discussion going forward. I really don't have an overt criticism at all really for Duke on recent past. I think it more gets down to as they develop out, say for example, of a comprehensive manual and these sorts of things, and as it becomes more real for developers, I just think we need to be open to the flexibility of having some more time. I could very well see it requiring some more time. And I certainly haven't seen anything from Duke saying that they're interested in limiting the time, so, you know -- so I think as that becomes needed, we'll want to bring that up and discuss that and look forward to, you know, using more time as it's needed.

CHAIR MITCHELL: And that all makes sense, but you're not saying Duke hasn't spent sufficient time on the topic now but that going forward you anticipate additional time will need to be devoted to the topic?

MR. GAJDA: I think that's accurate, Commissioner; yes.

CHAIR MITCHELL: Okay. Your slide seven makes the point that we're underestimating the volume and complexity to come. And I understand the larger

point you're making is that the Utility should consider this comprehensive DER requirements manual. And you pointed to Massachusetts as an example of a jurisdiction where a similar type of undertaking is ongoing, but --

MR. GAJDA: Right.

CHAIR MITCHELL: -- what do you mean by underestimating the volume and complexity to come? Help me just sort of speak in very real terms of what do you mean by that?

MR. GAJDA: Sure.

CHAIR MITCHELL: Realistic or practical terms is what I meant to say.

MR. GAJDA: Sure. So, for example, and again, I don't know that Massachusetts has everything figured out, but they have developed a comprehensive manual. And in developing that manual, that will not only involve Duke's spending time on their own which doesn't have to happen in the meeting, but I believe my gut tells me that then bringing that manual forward and drafts of that manual, that will now become a lot more real to the development community in terms of how it impacts their designs. And my gut tells me that's when the discussions are really going to blossom out

further. And so referencing my comment a minute ago, I believe that's where the time needed will likely increase and, of course, we can wait to see that happen, but I believe that's where it's going to increase.

And I think the -- it's volume and complexity. It's volume in that there will be many things to be discussed that haven't just quite come to the forefront yet and there will be complexity involved as well.

So it's, you know, it's a bit of just a prospective statement arguably without, you know, without me being able to deliver a lot, you know, to back that up outside of saying I look at the fact that the substantive amount of 1547 was roughly -- I've seen a statistic that said it's, you know, 10 times the size of the prior 1547 Standard. If you include all the header information, I think it's a 138-page document versus a 30-something page document. So that's certainly an increase in complexity and I just see it being some very in-depth discussions that we just haven't had an opportunity to have yet just because we haven't gotten to that point yet.

CHAIR MITCHELL: Okay. And that makes

sense. I mean, you anticipate the Standard increasing in complexity as we move forward and learn more about the operation of DERs on the system and reliabilities or implications. I get that. I just I wonder are you talking also about increasing numbers of DERs on the system? Are you talking about sort of the increased complexity with respect to what's there now and what we're going to learn going forward about, you know, how settings that should be made and ways that, you know, those type -- DERs should be operated or otherwise controlled by the owner?

MR. GAJDA: Yes. I think more so the latter. So I think it's not so much the number of DERs, because --

CHAIR MITCHELL: Yeah.

MR. GAJDA: -- ideally if this sort of thing happens right it will apply to five, it will apply to 500. I think it's more so, for example, voltage regulation, which is a well-understood thing on the distribution system today, the complexity of voltage regulation depending on how the Utility chooses to fully really implement 1547 that's -- I can see a lot of complexity showing up in that and a lot of discussion happening around that. So yeah, and just

really formulating what's written as a standard but then Duke or anybody taking that and then fully implementing it.

CHAIR MITCHELL: Last question for you, Mr. Gajda, then I'll pause and see if my -- any other of my colleagues have questions for you. Reliability, I mean, do you -- is it your opinion or do you think that we've got to sort of move towards this development of a comprehensive DER manual or devote more time and resource to this particular topic in the interest of reliability? Does reliable operation of the system dictate that we take action that is different than what -- the way things are proceeding now?

MR. GAJDA: I believe that what the requirements of a comprehensive manual, it has a relation to reliability, but what I think it primarily does is it really just helps the -- just comprehensively helps the interconnection process not just for developers but also for utilities. It's really just -- it's just a more -- it's a clear recipe book.

From a reliability perspective, I think that's really more so for the Utility to assess

internally. That is, you know, Duke has a handle on how many sites are out there. I think Anthony or Philip talked about, and the TSRG has talked about, they're moving ahead with doing simulations and various things. So yeah, I don't think I'll try to go too far out on a limb on that one, because I think that's really for them to assess and -- and the requirements manual only has a little connection to that in that if we want inverters to be set with particular settings based on what comes out of say Duke's studies and Duke's requirements, if you want that to be done properly, the better kind of more disciplined process we have that just helps the -- on the DER side we'll have a much better shot of implementing that --

CHAIR MITCHELL: Okay.

MR. GAJDA: -- because essentially if Duke has the requirements, we have to implement it.

CHAIR MITCHELL: All right. I follow you now, so you've cleared it up.

MR. GAJDA: Good.

CHAIR MITCHELL: I appreciate that additional explanation.

All right. I'll pause to see if anybody

else has questions for Mr. Gajda before we move onto NCEMC.

(Pause).

All right. Mr. Gajda, you are off the hook this afternoon. We appreciate your being here with us and your remarks.

MR. GAJDA: Yes, ma'am. Thank you very much.

CHAIR MITCHELL: All right. We will now hear from NCEMC. Mr. Dodge, I think you are with us and I believe Tony Eason and John Lemire.

MR. DODGE: Yes. Good afternoon, Chair Mitchell. This is Tim Dodge with North Carolina Electric Membership Corporation. How are you today?

CHAIR MITCHELL: Good. How are you?

MR. DODGE: Good. Good. Yes, like you indicated earlier, I'm an attorney by trade and not an engineer, and so rather than try to belabor these points or explain them in detail, we've asked John Lemire from North Carolina Electric Membership Corporation and Tony Eason from PDEMC to provide some responsive comments. Our comments and presentation have also been filed with the Commission already as well.

And with that, I'll turn it over to John Lemire to get things started.

MR. LEMIRE: Good afternoon. My name is John Lemire. I'm the Director of Grid Management for North Carolina's Electric Cooperatives. I've been with the Electric Cooperatives for eight years and have 16 years of utility experience in system operations and planning.

During my time with North Carolina's Electric Cooperatives, one of my roles has been coordinating with our member cooperatives on DER integration, interconnections, and their integration monitoring and coordination into our Distributed Energy Resource Management System also known as DERMS.

I'm joined by Tony Eason from PD Electric which is one of our 26 distribution cooperatives in the State. After my comments, Tony will provide a perspective from a rural electric utility on implementing DER interconnections in this technical standard. We have a few slides to support our comments, and as Tim said, they were filed with our comments to the Commission today.

Okay. Since joining the Cooperatives in 2012, I've seen the DER landscape transform across the

State. The level of activity and total number of megawatts connected has responded to legislation, tax incentives, equipment cost, and power purchase rates. Today, you can see that the Cooperatives have over 360 MW of connected DER across 2,300 interconnections, majority of those sites being small-scale solar.

The Electric Cooperatives serve from Murphy to Manteo and as such the DER deployment has not and will not be uniform across our membership. NCEMC and its member cooperatives are aware of the evolution of technical standards related to DER connection and the operations on the electric grid. NCEMC has closely followed this Commission's interconnection docket and FERC's Order 828 and 845 on both the small and large generator procedures.

These requirements and standards have been topics of presentations and discussions at state and national cooperative organized technical conferences that are regularly attended by engineering and operation staff.

The Electric Cooperatives acknowledge that each utility, including the distribution cooperatives who are independently governed by their boards of directors, continue to be solely accountable and

responsible for maintaining adequate customer reliability and power quality on its system. Distribution cooperatives have authority which is reinforced by FERC and NERC over the safety and reliability of their systems. And we do recognize that DER when not integrated properly within the distribution system will negatively impact both with the potential to cascade upstream to the transmission system as well.

Just as DER deployment on Cooperative systems will not take place at a uniform pace, the adoption of the IEEE Standards will not be uniform for our members, and we expect the adoption to reflect the existence and materiality of DER on any system.

NCEMC does continue to engage with our Member Cooperative Boards to consider the accelerated adoption of the IEEE 1547-2018 Standard to require DER to enable remote data acquisition and some limited level of control of the DER output. With increased DER deployment on their systems, these smart capabilities can support Cooperatives in managing their obligation to serve and provide reliable service to their members.

As we discussed at the March Technical

Conference, NCEMC and its member cooperatives are embarking on an initiative to create a distribution operator focused on reliability coordination. The distribution operator must be able to see the resource and understand its impact on the grid, and then coordinate that impact among the other operational components at work in concert to keep the lights on.

The integration provides visibility and coordination to our transmission providers such as Duke, Dominion, and PJM while maintaining autonomy of the distribution cooperatives. This visibility provided by the distribution operator erases the blind spot below the delivery point and the ability to coordinate DER to manage the growing complexity of the grid's request.

I'd like to ask Tony Eason to discuss the DER and the IEEE Standard from the rural cooperative perspective. Just to share with the Commission, Tony has both provided technical expertise to NCEMC's templates and the evaluation of the IEEE Standard itself.

Tony?

MR. EASON: Thank you, John. Hello everyone. I am Tony Eason. I'm a licensed PE in

North and South Carolina currently employed by PD and hope to retire here.

I have a diverse background in power generation, transmission and distribution over my 25-year career. The second half of my career focused on DER integration at the transmission and distribution level mainly from a protection engineer standpoint, but, you know, I had a lot of discussions with planning and operations along the way.

I was also part of a response that was coordinated through Edison Electric Institute back in, oh my, maybe 2014 timeframe. Several utilities came together and went up to Washington, sat down with FERC and was trying to slow them down just a little bit on Order 828 which was FERC's first attempt to reach down into the distribution to sort of invoke some of this ride through.

And one of your questions earlier was around can you apply 2018 to older inverters or older DER equipment. And I was in some discussion with some inverter manufacturers and one of them told me if you take it out of unity power factor, basically you break the anti-islanding functionality that was within it so there was no real well-defined function description

within the 2003 version of IEEE.

In 2018, that's what we were hoping to do was slow down 828 to allow 2018 to catch up with it. So that was some discussions we had with that group similar, you know, to how we're trying to invoke 2018 now, which I think is very timely.

Like I say, I plan to finish out my career here. PD Electric, we have 21,000 meters spinning on about 3,500 miles of line. We have 32 DER sites, mostly solar, mostly rooftop residential. Oftentimes, I say it's better to describe us in the miles per customer rather than customers per mile. You know, while it's a little bit humorous to say that it does carry a deeper message. Utilities vary even within the State of North Carolina quite a bit.

You know, if we were to invoke a single profile, I like that concept that John put forward and I think this could work. I just think maybe we need a couple of profiles because not all utilities are the same. The density is not the same. The conductors, the layout of the system. So it's a complex DER equation that we have to sort of find solutions to on the fly.

As smaller Cooperatives we may not see the

volume that Duke sees either, so we don't have the -- typically have the level of knowledge and experience with these sites that others do. That's where the resources of NCEMC and the NRECA, which is the national level of the Cooperatives, comes into play. John is certainly correct that NCEMC has taken a proactive role in communicating changes, generating documents, establishing training sessions. We have a system engineer meeting every December. This topic has came around twice. Once was Robert Harris with NRECA came down; he was very active in the 2018-1547 development. I was also in that main working group. I spent several years developing the larger document and was on several subcommittees in developing that.

But the collaboration doesn't stop at the NRECA level and the NCEMC level. I know a lot of peers in the industry. I know several names on this meeting as well. You know, we see each other at various informal meetings and training sessions across the United States. If you've been in this industry five-plus years, you kind of know the players and have to some degree discussed DER.

And we carry that to other Cooperatives within our North Carolina footprint. So anything I

learn, we share with other Cooperatives, and NCEMC takes the best practices of each Cooperative and spreads that around. So it's a very well-oiled machine the way it operates.

The key message I have is that we're going to start seeing the DER, I think it's already been covered, but we're going to start seeing DER with the 2018 Standard regardless of how we adopt it. So, you know, we as utilities either have to ride the train or get run over by it.

And like John Gajda said earlier, you know, it pretty much, the 1547 outlines the DER equipment and it does offer some guidance. Some sections are simply informative in nature to help guide the Utility on what direction we must go. And I love the analogy that -- I'm going to say John Gajda because John Lemire is sitting here also. So John Gajda provided the analogy of EV chargers and I like that. We at PD may have to slow down the ramp rates in which these EV chargers charge or we may have to define periods of time that are different from the periods of time that Duke would define, and then maybe the ramp rates would vary with Duke, and I know Dominion is on the call. So if your density is higher and your conductor is

bigger, then you know obviously you can charge things a lot faster. Then that same mentality falls over into the DER connections as well. You know, it just varies depending on what your system is.

But the 1547, one of the reasons why PD would like to adopt it is it clearly defines several things; trip versus cease to energize, which those are different things. It clearly defines when the DER must meet these parameters at the PCC which is the Utility side, or at the point of connection which is right at the DER terminals. That was always a question in the past. But there's a clear, a very clear delineation of size and output that gives us guidance and basically cleared up a lot of nonstandard discussions I would say. And coupled with interoperability capabilities, it does make it attractive to adopt 2018. Now, I'm not very familiar with the 2020 amendment to Annex B, which is, again, an informative section, but I think I got a good grasp on what it's got involved with it.

My question as we develop these -- or incorporate these standards, do we adopt it? The same question you had; do we adopt it going forward? Do we try to go backwards? As a small Cooperative, you

know, Grandpa Jones is my example. So I have Grandpa Jones with a residential inverter, he comes around for a 10-year renewal. Do I go tell Grandpa Jones look, you either got to bump this up to 2018 or get off the system? You know, I don't think that's very attractive for our membership and, you know, maybe even grandfathering some of these old ones in is attractive to retain them on our grid as we try to build upon the existing DER we have.

So, you know, it's a lot more questions out there that we as utilities are going to have to answer. And I love the comradery and things that I have seen so far, and it really helps us small Cooperatives by listening in on the more experienced Duke folks and to have the feedback from folks like Mr. Gajda. It certainly helps us small folks out.

So I would like to say thank you for your time and refer it back to John Lemire, I guess.

MR. LEMIRE: Sure. Thanks, Tony. That does conclude our comments and we're happy to answer any questions that the Commission may have.

CHAIR MITCHELL: Okay. I appreciate your comments today, Mr. Eason, Mr. Lemire. I don't have questions for you, but I'll see if any of my

colleagues have questions for you. I'm not seeing any hands raised at this point in time, so you all may be off the hook for the afternoon.

(Pause).

All right. No questions for you all, so thank you very much for your time and your remarks this afternoon. I look forward to continuing the discussion with you all in the future.

At this point there are no more presentations scheduled for the afternoon. Though representatives from ElectriCities, DENC, and the Public Staff are available for questions should there be any from the Commissioners. I will pause here to see if there are any questions from Commissioners for any of the other participants.

(Pause).

I'm not seeing any. I do have a question for the Public Staff. Mr. Josey, correct me if I'm wrong, it's my understanding that you have Mr. Metz and Mr. Williamson here.

MR. JOSEY: Yes. They are available for questions.

CHAIR MITCHELL: All right. Mr. Metz, if you would, would you please go on camera?

MR. METZ: Yes, ma'am.

CHAIR MITCHELL: All right. There you are. Question for you, and Mr. Williamson, you can chime in on this one too if you have an opinion.

You all heard Mr. Gajda's remarks about a comprehensive manual. I assume you heard Mr. Eason say that while that's sort of a good idea in concept, conditions on the systems will vary location to location, some being from denser, you know, denser areas and then sort of more rural areas like where his Cooperative is located on the system, and so a comprehensive manual should address various scenarios if we move in that direction. Does the Public Staff have any thoughts on whether it makes sense to develop a comprehensive DER manual in light of all the remarks today?

And let me ask it a different way, Mr. Metz. Well, would that be time well spent by all of these parties given everything else that you all are working on sort of, and matters of priority?

MR. METZ: I'm just thinking carefully about trying to answer this. I mean, just trying to take a step back and say okay, what is 1547? Looking over some of my notes it's a standard established for a

function specified and may need to be supplemented going forward. So even in that, there would be a dynamic element always -- it would always have to be taken into consideration if we were to go with ongoing Standard or a more deep dive at what -- we could spend our energy now and potentially work on this collaborative effort, but once it's completed this can't be shelved. It will be dynamic. It will have to be updated. We would have to work through and say okay, what will constitute an update when we would have to revisit it? What cycle would it have to be revisited?

Another aspect that I have some concerns about is 1547 isn't retroactive. So we could work towards this goal of a comprehensive design, but how would we apply it based upon the penetration levels already exhibiting on the system? That creates another complexity, another dynamic of the system; how this manual would be alive.

So maybe to answer your question more blunt, I think it would be of value for stakeholders to get together and understand where we might want to go. I would also just take heed of we can't lock ourselves in.

CHAIR MITCHELL: Okay. One last question for you, Mr. Metz. I -- at least I think I have fleshed out or have a better understanding of the Utility, of the comprehensive manual of which or about which Mr. Gajda spoke, and concerns relating to reliability, inverter settings related to reliability. Is there anything else we need to be doing to ensure the reliable operation of the system in light of current penetration and expected penetration?

MR. METZ: Yes. So on the -- I want to maybe take a step back and say are we mixing repeatability versus reliability? When we sort of look at Interconnection Standards, we look at can the Utility design the system and always have expected results. That's what I mean by repeatability. So if the Utility who's responsible for the distribution system is relying on DER generation to provide these services, what happens when those DER services are no longer available? The unit can go offline. System load can change five years, 10 years, 15 years down the road. Utility needing to rely on DER. Are we also creating more burden for the Utility to provide a backstop to the service?

For example, if we're relying on reactive

power to slow for a voltage condition and we lose that DER for whatever reason, what will the Utility do? What will the people who rely on service from that feeder do? Will this result in the Utility now needing to build an additional backstop? Or would we have to curtail load off that particular feeder? And then try to deploy that in scale, because I think Tony made a good point of saying well, circuits are different as we look across the entire state. I mean, circuits are different as we just look at Duke. Trying to create a one-size-fits-all would possibly be very problematic.

CHAIR MITCHELL: All right. Thank you, Mr. Metz.

All right. I want to give -- Mr. Breitschwerdt, I want to give your presenters an opportunity to respond to the questions I've asked of Public Staff and CCEBA and -- well, I didn't have any for NCEMC, but just if they have any sort of final thoughts or remarks, again, in response to the questions asked today of the others.

Let's see if Mr. Williams, Mr. Baker --

MR. BAKER: This is Mr. Baker. I don't have anything further. Thank you.

CHAIR MITCHELL: Okay.

MR. WILLIAMS: This is Anthony. No, I think I'm good right now. Thanks.

CHAIR MITCHELL: Okay. All right. Thanks, Mr. Williams.

MS. KELLS: Chair Mitchell, this is Andrea Kells. Can you hear me?

CHAIR MITCHELL: I can. Good afternoon, Ms. Kells. I can't -- oh, there you are.

MS. KELLS: Okay. Hi. I'm here with McGuireWoods on behalf of Dominion. May the representatives from Dominion offer a brief comment on what they've heard here today? I can introduce them.

CHAIR MITCHELL: Yes, please do. I would appreciate that.

MS. KELLS: Thank you. Okay. We have Mike Nester, who is Manager with Electric Distribution DG Integration and Mamadou Diong who is a Consulting Engineer with DER Integration and Strategy for Dominion. Y'all go ahead.

CHAIR MITCHELL: All right. Gentleman, y'all may proceed.

MR. NESTER: Good afternoon, Chair Mitchell.

CHAIR MITCHELL: Good afternoon, Mr. Nester.

Good to see you.

MR. NESTER: I appreciate the Commission's time this afternoon to participate in the session about IEEE 1547-2018. And Mamadou Diong and I have just a few comments as it pertains to Dominion Energy North Carolina and the implementation or the development of the Standard. And I will let Mamadou speak to the actual, you know, technical parameters. You know, Dominion is involved in the working groups and Mamadou has a leadership role in the working group that's developing the Standard and also, you know, documenting the Standard just at a general level process though.

You know, Dominion Energy North Carolina supports the capabilities that are represented by the Standard. You know, we do view it was a equipment specification standard as opposed to a utility implementation standard, and there is, you know, some distinction between those descriptors. But in the equipment capability standard, we support the ride through and the VAR support capabilities, but we believe that the inverter capabilities, you know, as we view inverter capabilities today should be utilized at the discretion of the Utility to ensure the safety,

reliability, and operability of the grid for all customers.

Some of the participants in the session today have also, you know, issued similar comments that the distribution grid is a dynamic grid. It was originally designed for radial flow and we are designing it -- trying to design it to accept bidirectional flow. But it is, you know, the vehicle by which all customers, you know, certainly utilize electricity, the provision of service, you know, for the benefit of those customers.

And, you know, the Utility is the entity that has the regulatory responsibility for ensuring the safety, reliability, and operability of the grid. And that is, you know, one regulatory responsibility that we take very seriously. And just a challenge as we consider the use of inverter capabilities is the distributed energy resource doesn't necessarily share that same regulatory responsibility.

But again, you know, we are very active in the working groups with IEEE that are developing the Standard. As was mentioned earlier, there's not a UL-certified inverter on the market today that has been tested to the Standard. You know, there are some

considerations once that does come to the market in that the inverters are tested in a standalone fashion; they're not tested as a system. And so there are some questions on how, you know, even UL inverters that are tested to these standards will operate with each other at a particular solar farm installation or, you know, interoperate with other inverters that are connected to the same circuit or to the same distribution bus.

So there's definitely some challenges that could be addressed by all stakeholders.

But I'd like to turn it over to Mamadou Diong, he's a Consulting Engineer in our DER Planning Group, for some additional comments from a technical perspective. Mamadou?

MR. DIONG: Good afternoon. Can you hear me? Good afternoon, Chair Mitchell and good afternoon Commissioners. Thank you, again, for giving me the opportunity to join the discussion. And I want to echo what Mike Nester just mentioned.

Again, to give you a little background on me, I've been involved with the 1547 working group since 2012. And I'm also an Officer in 1547 and also helping put together a guide for the 1547 Standard, because we recognize that it is a very complex

standard, it has -- although it is just 138 pages long, it has a lot of new additions which could be a little bit challenge for the DER community to be able to understand it and implement it as it is intended to.

Now, with that established, I listened very careful to a lot of the comment all of the presenters made, and I was hoping that I can give a little bit of clarity to the Commissioners and to Chair Mitchell.

The IEEE Standard is a DER Standard. It is trying to provide some criteria and requirement for how we can interconnect a DER. And when we say DER, we mean by any electric power equipment or source that is directly connected to the power system. And it can be not only inverters -- again, I don't -- I just want to make sure that we understand that it is a technology agnostic standard. It includes all DER equipment - generators, energy storage, and inverters.

Now, I think the confusion may come from the fact that UL 1741, which is a standard, a test to the 1547 Standard, it's mainly focused on inverters and converters. And the UL 1741 right now, it is being revised to be a little bit more in line with the 1547-2018 Standard. There's a lot of work that's

going on and I think John Gajda, that I know very well, and some other presenters have summarized that very well, but it is still a work in progress. And as we know today, just like Mike mentioned, there is no inverter equipment that meets the requirement of UL 1741 -- sorry -- the 1547-2018 because, again, it is a work in progress to be able to put together the Standard -- the testing regiment and have lives ready to test those equipment to that new standard.

And I hope that's helpful. Because again, I heard a question about is it just inverter; no, it's not just inverter. 1547 goes beyond inverters. But UL 1741 yes, it's focused on inverters.

Now, another item that I wanted to comment on is that the 1547 Standard has those requirements, especially the 1547-2018. It addresses some of those requirements. And the reason the 1547 Standard was revised is that they recognized that we're getting higher penetration of DER into the power system and it may be different across different territory utilities. In a sense, my colleague Tony Eason in their territory they may not have the same penetration so that's the recognition. But knowing that the penetration is increasing, we need to make sure that the DER

equipment, when they come to the system, they play well with the system and they don't cause harm to the system. They're to help the system instead of hurting it.

And so that's why most of the requirement, I will say mainly all of it, are geared toward what the inverter should be capable of doing because it was recognized that if they're able to do A or B, then they will be able to help the grid or its electric system when it needs it so that we don't lose a grid which means losing the customer or putting the customer in the dark.

But one thing that the Standard does not address, again that's something that leaves to the Utility to figure out, is how when you implement some of those requirement that, let's say that all the inverter manufacturer going to adopt those, and they all meet those 1547-2018 requirement. How are you able to deal with those, because everything you do in the grid has -- may have some unintended consequences.

What I mean by that is that the grid is designed, just like Mike mentioned, that to be able to serve the system and the loads and to serve the need, but then when you inject reactive power, then that has

a tendency to raise the voltage. When you inject push current, it raises the voltage. So some way you have to be able to ensure that the voltage and the current are not -- or the frequency are not outside of what the Commission has said we should maintain that within that filing.

So there's a lot of items that are not being addressed in the Standard that the Utility -- just like Duke also mentioned in its presentation, Duke is putting together plans to be able to address those and continue operating system safely and reliable. And I hope this is the case also for Dominion. We are, again, actively engaged with 1547 and we know a lot of the things in there are meant to help the grid and we're all for the DER equipment to be able to offer all those capabilities. We all welcome those.

And if I can, one other topic that I wanted to mention, I want to return back to the 1547 guide. I am actually Secretary for that Standard guide. The guide, once it's out, which we're hoping it will be sometime end of 2021, early 2022, I believe will be a welcome addition to a series of Standard in 1547 in that it can help explain to whoever or any stakeholder including the Commission again, how and what was the

rationale behind the 1547 Standard. And I'm bringing that up because I'm thinking if we're able to give time for that Standard to come out, to that Standard guide to come out, it will help us remove some of the burden of coming and going back and trying to understand and debate what exactly the Standard was trying to do.

So the goal for the Standard is to help anyone understand how the Standard may affect the Utility, may affect the equipment vendors, may affect the developer, and what the developer may need to worry about, or make you to understand on the Utility perspective in a sense. Again, John Gajda mentioned in his presentation that the utility engineers know things that the DER engineer doesn't know. But I will add onto that, also the developer may not know, the other Stakeholder may not know. So it's important that everyone understand the other's perspective and see how one thing may affect the other one.

So it's just a lot more involved in implementing 1547. It's just -- it's mainly the equipment, but the Utilities do have to understand how it can affect this electric system.

But that's what I wanted to comment on and

I'm hoping that it's helpful. Again, I've been taking notes to make sure that some items that I wasn't -- or were not totally or fully addressed. I flushed them a little bit to help you along, because again, 1547 is very technical. Some items maybe may have been misunderstood or some things may not be well explained. I hope this is helpful.

CHAIR MITCHELL: Thank you, Mr. Diong. Your remarks are helpful. And I -- so I want to make sure I'm hearing sort of the important points that you've made. I mean, the guidance on the Standard isn't going to be issued until the end of 2021, 2022, and that will -- your opinion is that that -- once that guidance comes out, it's really going to advance the discussions that have been ongoing about the implementation of the Standard. But until then, you also -- I mean, you see value in the stakeholders continuing to work together in discussing implementation of the Standard?

MR. DIONG: Yes, I do.

CHAIR MITCHELL: Okay.

MR. DIONG: And I agree, Ms. Chair, and that's exactly what I meant. That guide I think will be a great compliment to the discussion. And I really

don't want us to redo all the five-years of discussion that we've done to come up with what the 1547-2018 has done. That's a lot of time. Five years is a long time. So the guide hopefully can help with that process.

CHAIR MITCHELL: All right. Thank you, gentlemen. Any questions for the gentlemen from Dominion from Commissioners? Commissioner McKissick?

COMMISSIONER McKISSICK: I just want to get some clarity as well on the last points that were discussed. I gather that 1547 is going to go beyond inverters in terms of looking at all DER equipment; is that correct? I mean, because I thought it was basically establishing more of that uniform standard dealing with smart inverters and their functionality, but you're saying it goes beyond that scope; is that correct?

MR. DIONG: That's correct. This is Mamadou again. This is correct. The 1547 Standard try to be technology agnostic, so it covers beyond inverters. It could be a battery storage. It could be just a rotating machine. So that's why the 1547 Standard created different categories recognizing that some equipment may not be able to do all that the inverters

are capable of doing, but they still have some requirement to meet if we want them to adopt some of the 1547 requirement.

COMMISSIONER McKISSICK: Okay. And one quick follow-up, because I read a lot about smart inverters and their functionality and what they're capable of doing, but then I also read information about hybrid inverters. Are hybrid inverters kind of a subsection, subcategory of smart inverters in terms of being a type of it or how are the distinguishable?

MR. DIONG: To be honest, Mr. Commissioner, I'm not quite sure what they mean by hybrid inverter. One thing I can say that being technology agnostic means that if it is connecting to the power system and trying to push power into the power system, then it has to meet the 1547 requirement. If it's deciding to not connect in parlor with the power system, then yes, they may be off -- they may not need to meet the requirement for 1547. But as long as they're pushing power to the power system, they are interconnecting with the power system and parlaying for a certain time; yes, 1547 will still apply.

But to your question, I don't understand. I don't know exactly what it means, "hybrid".

COMMISSIONER McKISSICK: Well, when I was reading about hybrid, they referred to it as being, you know, like with battery backup, that type of thing, or some type of capability such as that whereas, you know -- so let's say your regular inverter it detects some difference in voltage and it automatically shuts off where your smart inverter is automatically going to have functionality when it begins to monitor things. It brings on a supplemental support and it maintains it and monitors it until it determines what the perhaps this force of that voltage fluctuation might've been in terms of responding, so there's a lack of what I would call interruption to the grid. But it distinguished the two. That's what I wasn't quite sure, but --

MR. DIONG: Okay. So no, I think I see now. Yeah.

COMMISSIONER McKISSICK: Yeah.

MR. DIONG: So I think now I see what you mean by hybrid. So it's almost like you having something that's not typically parlaying with the Utility, with now some of the devices that I recognize by 1547 as needing to meet some of those requirements.

COMMISSIONER McKISSICK: Exactly.

MR. DIONG: Yes, in this case, yes, you are correct. It will need to meet the Standard. And the 1547 Standard didn't exactly explain that case and that's some of the -- one of the example of the items that the guide is actually trying to address as well. So with that guide that I mentioned, it's called 1547, that too has a component where it talks about that. And I think it has a term that I don't -- I don't quite remember the term we used. It's a technical term to define those hybrid systems.

But yes, you are correct it still meets that. It needs to meet the requirement.

COMMISSIONER McKISSICK: Thank you, sir.

MR. DIONG: No problem.

CHAIR MITCHELL: All right. Thank you, Commissioner McKissick.

Any additional questions from Commissioners?

(No response)

All right. It looks like there are no additional questions from Commissioners, so at this point we have come to the end of the afternoon. I want to reiterate my thanks to all of you for your remarks and presentations to us today and helping our understanding of ongoing efforts to implement the

Standard.

And with that, we will be adjourned, and let's go off the record.

(The proceedings were adjourned)

C E R T I F I C A T E

I, KIM T. MITCHELL, 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.

Kim Mitchell

Kim Mitchell