PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, January 29, 2019

TIME: 2:00 p.m. TO 5:30 p.m.



DOCKET NO.: E-100, Sub 101
E-2, Sub 1159
E-7, Sub 1156



BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Charlotte A. Mitchell

IN THE MATTER OF:

Petition for Approval of Generator
Interconnection Standard
and
Joint Petition of Duke Energy Carolinas, LLC,
and Duke Energy Progress, LLC, for
Approval of Competitive Procurement of
Renewable Energy Program

Volume 4

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

FOR DUKE ENERGY CAROLINAS, LLC, AND
DUKE ENERGY PROGRESS, LLC:
Jack E. Jirak, Esq.
Associate General Counsel
Duke Energy Corporation
410 S. Wilmington Street/NCRH 20
Raleigh, North Carolina 27602

E. Brett Breitschwerdt, Esq.
McGuireWoods, LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

FOR VIRGINIA ELECTRIC AND POWER COMPANY, d/b/a
DOMINION ENERGY NORTH CAROLINA:
Andrea R. Kells, Esq.
McGuireWoods, LLP
434 Fayetteville Street, Suite 1600
Raleigh, North Carolina 27601

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

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Peter H. Ledford, Esq.
General Counsel
Benjamin Smith, Esq.
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR INTERSTATE RENEWABLE ENERGY COUNCIL:

Laura Beaton, Esq.
Shute, Mihaly & Weinberger LLP
396 Hayes Street
San Francisco, California 94102

Lauren Bowen, Esq.
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

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

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Karen Kemerait, Esq.
Fox Rothschild, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR NORTH CAROLINA PORK COUNCIL:
Kurt J. Olson, Esq.
The Law Office of Kurt J. Olson
Post Office Box 10031
Raleigh, North Carolina 27605

FOR CYPRESS CREEK RENEWABLES:
Benjamin Snowden, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

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

FOR THE USING AND CONSUMING PUBLIC ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

Jennifer Harrod, Esq.
Special Deputy Attorney General
Teresa Townsend, Esq.
Special Deputy Attorney General
Department of Justice
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Tim R. Dodge, Esq.
Layla Cummings, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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E X H I B I T S (Cont'd.)

P R O C E E D I N G S

CHAIRMAN FINLEY: All right. Before we get back to answering questions, there are a number of -- several parties, at least, who have sponsored witnesses, but those witnesses have been excused and don't have to be here in person to support their testimony. Please, if you have a witness that falls into that category, don't forget to move anyway that that witness' testimony be copied into the record, okay?

Commissioner Brown-Bland, I think, was asking questions.

COMMISSIONER BROWN-BLAND: Yes.

JOHN W. GAJDA,
GARY R. FREEMAN,
JEFFREY W. RIGGINS; Having been previously sworn,
Testified as follows:

CONTINUED EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q I was trying to ask Mr. Freeman, but he keeps punting to his colleagues. Mr. Freeman, on page 10 of your rebuttal testimony there's a chart there that describes the steps in the system impact study process, and one of those processes is mitigation options. Now, does Duke now consider offering mitigation options to be a standard part of the process or is that just for the generators covered by the settlement that was filed last year?

A (Freeman) I think it was -- the general intent was to use that for the projects covered by the settlement process, but I'll, again, defer to my colleagues, but I think we've probably likely used that outside of that process. But I think we were saying earlier that we'd like the flexibility to use that, but we're -- I guess I'm not sure I would support, you know, kind of codifying that into the standards themselves at this point. I mean, we're -- I think we're using it very effectively at this point.

Q So you wouldn't quite consider it standard, but you use it regularly or --

A That's how I'm, you know, kind of interpreting it. You may have a different thought.

A (Riggins) It's not limited to settlement projects today. It's being applied on all Section 4 projects.

Q Okay.

A (Freeman) But distribution projects is where we're applying it.

Q Okay. All right.

A Distribution connected projects.

Q All right. And on page 15, also in your rebuttal, you discuss those -- you --

A Rebuttal or direct?

Q Rebuttal. You discuss the mitigation option process. And the question is if -- if it goes against the plain language of the interconnection process, why didn't you come to the Commission to seek approval of that before committing to that process under the transformer nameplate settlement?

A So I've got to -- I've got to catch up with you here a minute. So you're -- you're where in my rebuttal now?

Q It was on -- on page 15.

A Okay. Would you mind asking your question again?

Q And if that process is against the plain language of the Commission's interconnection procedures, why didn't you come to the Commission to seek approval of that change before you committed to -- to it under the settlement?

A Oh, gosh. I've got to think how best to answer your question. I think under the Settlement Agreement, I -- I mean, I lose track and may defer to our attorneys. I thought we brought the settlement to the Commission for approval, I think, subject to -- to check. And then -- and I think your question may be around why didn't we come to the Commission when we expanded it to other projects? Is that your question?

Q And -- and instituted this mitigation option piece.

A Well, again, I mean, I think between, like we talked before, the mitigation options, the cure process, offering extensions are things that are probably not clearly identified in the interconnection standards, but all in an effort to try and be supportive of, you know, the state's intent to adopt more and more renewables, we felt like it was, you know, a good decision to kind of support that.

Q Does it harm or in any way negatively impact the projects that are later in the queue?

A It does. I think we talked earlier it does have the potential, yes, to -- to harm other projects in the queue.

Q And --

A So an extreme would be, you know, hard -- hard no's, and I -- I would suspect that that would probably generate a, you know, significant increase in informal disputes and things like that. So, I mean, there's a balance in terms of, you know, trying to support the projects and -- and stick to the -- to the standards as well.

Q And do you have the experience of developers objecting to the mitigation option?

A Not that I'm aware of, no.

Q So --

A I mean, I don't think they're objecting --

Q -- if you've gotten --

A -- to the -- the offering of the mitigation options. I think we'd probably get, you know, challenges around exactly what the particular mitigation option, you know, is.

Q And so if you were to get objections to -- to those options, you'd consider that to be an -- an exception to the rule? It's not an everyday -- it's not a routine occurrence that the developers want to complain about the option, is it?

A I'm kind of even looking over to Public Staff a little bit. I mean, I think we -- we do get a number of informal disputes or, you know, challenges around the mitigation options themselves and get challenged on, you know, the cost assigned to -- to, say, each mitigation option as well, yes.

Q I guess I'm -- I'm trying to get a feel. Does that -- does that happen often or you wouldn't say so?

A (Riggins) I would say it happens quite often. So on all projects now where they are impacted by Method of Service Guidelines, they're going to get mitigation options that gives them, you know, two or three different options for interconnecting. Downsize is one that Gary mentioned earlier. So I would say quite often we at least get challenged on what the results are that we're presenting and how those studies are done and how we arrived at those answers. Not all of them arise to a formal dispute or an informal dispute, but we often get questions about the results.

Q Okay.

A (Freeman) But I would also suggest that if we did offer mitigation options, we'd -- we'd have even more, you know, challenges and disputes.

Q All right. And with respect to that chart that we mentioned just a minute ago on page 10 of your rebuttal, why are the interconnection customers being given 15 days to select the type of inrush study? Why -- why is this choice offered?

A Well, again, the -- the 15 business days is -- I'm not sure that's codified, but, again, it's what we feel is a reasonable amount of time to, you know, share the information with the developer and give them, you know, the opportunity -- a reasonable opportunity for them to respond back. And then in some cases this is where -- I can't think of a specific example, but where a developer may ask for the extension, which is kind of another, you know -- you know, kind of item that we're kind of thinking about in terms of offering flexibility, where they'll ask for an extension on top of that.

Q Okay. In your testimony you've indicated that approximately 7,000 MW of renewable generation has been or will be interconnected to the distribution and transmission network based on legacy PURPA projects combined with House Bill 589 procurement directives. Could you provide any further breakdown of exactly what the 7,000 MW encompasses?

A I mean, it's kind of subject to maybe -- maybe check, but --

Q If you can't, we would accept a late-filed exhibit, but...

A Well, I mean, I can kind of generally describe it, that, you know, we've got, say, pushing 3,000 MW on the system operating today. We've got probably another 1,000 to 2,000 MW of projects that have qualified for --

they've established their LEO and they've qualified for PURPA rates under either Sub 140, Sub 148 avoided cost rates. We've got a number of projects that we've negotiated Power Purchase Agreements with those projects under PURPA, and that represents between North and South Carolina, I'll say, another 1,500 MW or so. And then the remainder -- at least when we filed CPRE, the remaining amount was the 2,660 number that we've shared before. That was what we intended to procure through the competitive procurement process.

So it's designed to kind of be flexible, but the goal was 7,000 MW. Whatever -- whatever was not procured under PURPA would be procured under CPRE.

Q Okay. And you've also indicated that the Companies have been averaging about 600 MW per year in interconnections. What's the actual number of projects that you've interconnected for 2018?

A Oh. I'm not sure I have the exact number of projects, but I think I communicated yesterday that we connected up 537 MW. So we think in terms -- I mean, it's hard to bounce back and forth between number of projects and MW. What's most important to -- to the Utility is the number of MW you're bringing on to the system, so 3,000 MW, which is close to where we are today, you know, represents three, almost four nuclear plants in terms of MW and capacity being, you know, connected up to the system.

Q We were thinking on that Figure 6 in your testimony it looked like about 500, so we're in the right neighborhood.

A Right.

Q Okay. And on page 32 of your direct, right near the end there you tell us that there's one minor exception to the state FERC jurisdictional divide in terms of determining which generators use which interconnection process. What's the -- what is the minor exception?

MR. JIRAK: Could you repeat -- is it -- what page?

COMMISSIONER BROWN-BLAND: Page 32 of his direct, right on line 20 right at the end.

A Thirty-two on direct. If not, it must be interconnected under the FERC OATT with one minor exception. To be honest with you, I'm -- I'm drawing a blank as to what that minor exception is. Can we provide that to you in a follow up?

Q Sure. Mr. Riggins, you -- do you know?

A (Riggins) I'm trying to read what he read.

A (Freeman) Yeah.

COMMISSIONER BROWN-BLAND: See, that's how it is when you're a short-timer, you know.

MR. FREEMAN: That's right. Plus, you know, you get old and you forget, too.

COMMISSIONER BROWN-BLAND: And let the record reflect that we've all been kidding with Mr. Freeman, so if something looks kind of funny in there, we'll know. We're just making reference to this being his last day on the job, or near the last day.

A (Riggins) Definitely want to clarify, but I think the one exception may be that under FERC, you know, there's -- they deal with transmission and distribution slightly differently and if they're QF or non-QF. So there is one instance where they're non-QF, and then it gets into whether it's distribution first use or non-first use, and that may be what was being referred to, but I think we should clarify and follow up.

Q All right. I appreciate that. And now switching to your rebuttal testimony, Mr. Freeman, on page 11 you've stated there that the line voltage regulator -- that projects with line voltage regulator impacts can increase the time of the system impact study by as many as 445 calendar days, and that that time is controlled by the developer. What percentage of projects have those LVR impacts, and can you put a number on it?

A (Freeman) I'm not sure I can put a number on the number of projects that are impacted by LVR. I mean, I think, you know, since we came out with the Method of Service Guidelines, the guidelines were designed to, you know, kind of provide guidance as to where you connected up a facility, so I would -- I'm speculating a little bit that, you know, since those guidelines were put in place that we've had, you know, less and less projects being impacted by the LVR. In other words, a lot of that guidance really is designed, that, you know, the -- the best place to locate utility-scale projects on a distribution system is close to the sub.

Q All right. And so --

A And we can try and get a number for you.

Q Percentage wise you're not able -- you don't feel comfortable; kind of ballpark it? I mean, if you don't, that's fine. I'm just trying to figure --

A I -- my guess would just be a wild -- a wild guess. I mean --

A (Riggins) I would prefer to send it in a follow up. We can ask our study team and try to determine how many projects have been notified of impact by LVR, but I don't know that number.

Q All right. Thank you. On page 13 of your rebuttal you state that developers are seeking to challenge the Company's technical conclusions where the developer's -- developer's only viable option is withdraw. What percentage of developers are doing that? Is it all the developers or --

A (Freeman) Point me to the specific line so I can read exactly what I had said.

Q Page -- let me see if I can find it.

A I found it.

Q It's in 10 --

A So lines 10 --

Q -- 10 --

A -- 10 through --

Q Yeah.

A -- through 13.

Q Uh-huh.

A I think what I -- I mean, there is -- you know, I mean, I'll go back to we -- we will provide an interconnection option to every -- every developer under, you know, our obligations to provide that interconnection request. By viable, you know, if a project is being assigned, you know, a multimillion dollar upgrade, you know, it becomes questionable as to whether it's a viable project or not. So my point there is that, you know, in a lot of cases, you know, the developer likely will withdraw, but they will exhaust pretty much all, you know, kind of challenges and options to challenge us on, you know, the -- the assignment of those upgrade costs before they would ultimately withdraw.

Q Is that --

A We've had projects -- distribution size projects that have triggered, you know, multimillion dollar upgrades, and a small 5 MW project, it's hard financially for that particular project to really make that project, you know, I'll call it, viable.

Q And in these scenarios where that withdrawing is their only option, are most of them challenging your technical conclusions?

A I would say that generally that's one of the challenges that we get, yes.

Q I'm looking for like how -- how -- what's the percentage of developers who make that kind of challenge?

A Well, this somewhat goes back to what we talked about earlier in terms of, you know, trying to offer them mitigation options as well, you know, to try and find, you know, the appropriate size to where they can make the project viable. So I think there is -- there's no real, you know, kind of quantifiable statistic there, but I'll go back to, I mean, we've tried to, you know, support and figure out ways to encourage every one of these projects to be viable.

Q All right. How many interconnection projects have filed Notices of Dispute?

A (Riggins) You mean disputes that rise to review with Public Staff or all Notice of Disputes?

Q I think all Notice of Dispute.

A Yeah. I don't have that number, but we can we get that number for you.

Q Do we know the percentage of Section 4 projects?

A Relative to what?

Q To the disputes? Or Section 3 or Section 2?

A (Freeman) I would assume the majority -- I mean, I think even Public Staff could confirm on the projects that end up going to, you know, a Notice of Dispute are generally mostly all -- I'm kind of saying generally mostly all, you know, Section 4 types of projects.

Q All right.

A I'm not aware -- if we've had minor upgrades on a non-Section 4 project, they've been relatively minor.

Q All right. And on page 21 you mention that the interconnection customer requesting nonstandard technical solutions which later result in increased cost to ratepayers. Have you discussed that issue with the Public Staff, and -- and what's the Public Staff said about it? What's their opinion?

A Are you on my rebuttal testimony?

Q Yes. On page 21.

A Yeah. I think -- you know, I would kind of answer the question with what Mr. Gajda shared -- I don't know if he shared it earlier -- that, you know, we've -- we've had at least, you know, one project that I'm somewhat aware of where we created a nonstandard kind of solution that down the road when we had to reconfigure the -- the circuit and do other work, that we couldn't accommodate that project at that point, and we did have to spend, you know, money to upgrade that project to -- to continue to accommodate it. Because once that project is online and interconnected, I mean, we feel like we've got an obligation to continue to support, you know, that project's interconnection.

Q Did you bring that situation to the Public Staff, that they made a comment, or what did they say to you?

A (Gajda) That -- I think that -- we may have since then. That occurrence -- that interconnection that we're thinking about I think occurred in roughly 2010 in DEP, and I think the occurrence of the additional construction was just a few years after that, so -- so we probably did not at the time just because we weren't -- this was before Method of Service Guidelines. This was really before the -- the rapid uptick of solar and -- and, you know, considering all these -- these sorts of components. So it was well documented, and that's why we brought it up since then because it's a -- it's still a very good example of this issue that'll continue to grow.

Q Is it -- is it --

A (Freeman) And --

Q Go ahead.

A Well, and there's another example that I don't think was brought before the Public Staff or the Commission, but it's another example of what we're concerned about going forward, is that if we're -- you know, need to, you know, reallocate load to different circuits, you know, what kind of impact does that have on the interconnection facility?

We did have a project in DEC that

interconnected back in like 2011 time frame, and it was like a 4 MW project that connected up to our 44 kV system, which is kind of your lowest transmission voltage system. It's an old legacy system. It doesn't have any voltage control on the system. That 4 MW project was -- created voltage issues for our wholesale customers. You know, we had low voltage in the summer, high voltage in the spring and the fall. We tried as a mitigation, I'll call it mitigation, to solve the problem with doing manual work at substations. We ultimately had to come and -- and upgrade that part of the system to a higher voltage 100 kV transmission system.

So that's a real example of why we're so concerned about, you know, studying impacts and locating projects where we think we can support them for the long term.

Q So -- and the same question just in terms of seeking other opinions that you -- have you discussed this kind of issue with NCCEBA or NCSEA?

A I wouldn't know, say, specifically, but I think in general, I mean, we've discussed it.

A (Gajda) Well, what I can think of is that as we began to implement Method of Service Guidelines and -- and there were discussions with stakeholders, so -- which

NCCEBA, NCSEA were -- were likely part of those. I think those stakeholder meetings were advertised to developers, okay, so -- but as we talked about, some of the components of those guidelines were developed specifically to get at this issue, so -- so they -- and I believe in testimony, I believe it was in my testimony, I have documented some stakeholders meetings that we had, so in some of those the LVR policy specifically addressed some of these issues about double circuiting and some of these things, and so -- so in those forums we did describe this -- this issue, yes.

Q Okay. And Mr. Freeman, you -- you just mentioned about a situation where a -- where a system or that portion of the system was pretty old. And I guess that's one of my questions. If you take out -- take away legislative and regulatory changes and -- and enabling kind of laws, would you be -- if we were to look back, say, 15 years ago even, would -- would Duke have been in the position to, as a technical, physical matter, make these -- make the level of interconnections that -- that you've described, say, in your Redirect Exhibit 2? Would -- would there have been any way 15 years ago -- was Duke in a ready position and would have been able to -- to make these kinds of changes to the grid?

A (Freeman) I'm not completely sure I understand the question, but if -- if we would have seen, for example, what we saw in 2012, 2013, if we would have seen that back, say, in 2005 or so, would we have been ready --

Q Or early 2000s, uh-huh.

A -- to provide the same support that we do today? I think the answer is yes.

Q All right. And -- and what I was getting at is the -- the current -- the system that you had, was -- was it built and was it contemplated that you'd have this level of interconnection occurring? Do you think it was built for that?

A Generally, no.

Q But you still think, given that there's change on the horizon, that even then you could have met the challenge?

A Well, we'd meet the challenge the same way we are today.

Q You'd have been properly staffed and had the resources that you needed?

A Right. And study the projects, assign the upgrade cost to the, you know, to the interconnection customer. Yeah. I think we would be.

A (Gajda) I'll just mention one thing. I mean, the architecture of the -- of the system is the other piece of that. So Mr. Freeman mentioned the 44 kV system as an older infrastructure. It -- it's, you know, older just in that perhaps it's not a -- we're not expanding that part of the system, but it's perfectly fine and functioning and doing what it's supposed to do. The architecture of that type of system was clearly not as adaptable to distributed generation. And so -- but obviously when it was built and -- and designed, that was not a consideration. So the architecture of the -- certain parts of the system is the piece that's difficult to -- to change in -- in, you know, certain periods of time.

Q And so going forward, it's -- the architecture better supports -- we've got new -- a new -- a new situation or a better situation that allows you to serve the interconnection customers maybe at a higher level?

A In some respects, to the degree that we understand the nature of how the facilities operate. So we -- we certainly have learned a ton in the past 10 or 15 years. I think it's -- one of us has described in testimony, I think Mr. Freeman mentioned about, you know, greater amounts of penetration may involve a massive redesign of the distribution system. I think -- I think I've said some similar things. The architecture of the system, though, will have challenges putting more generation on the distribution system, especially utility scale, just because of its architecture is what it is, and -- and it's not easily changed overnight.

So I don't know that we've made great changes in architecture because, frankly, that would -- that's a -- that now then becomes a significant impact to -- to base rates and to ratepayers if we were to make a wholesale change in architecture to the system. That's been the piece, I think, that we're not -- that -- that, you know, we're not prepared to do immediately because of those sorts of impacts.

Q All right. And Mr. Gajda, I did have one question just for you. You mentioned before the solar farm that kept tripping off, and I just wanted to follow up. Did that -- did that event of that solar farm tripping up -- tripping off and you figuring out what was going on, did that inform or change the Company's practice or procedure in any way?

A Indirectly so. I think what we learned most significantly from that when we -- there were several things we took away. We -- I mentioned we contacted the inverter manufacturer, had this discussion with them. They said they'd seen the situation before in -- in some isolated cases in other countries. And at that point our conversation was kind of trilateral because we're talking with the developer and the inverter manufacturer. The inverter manufacturer offered to the developer that they could fix the problem by reprogramming the inverter with a firmware update. They said it would take about six weeks. It would cost the developer money.

We -- we followed up on that a number of times and -- and ultimately, the -- the developer wasn't willing to spend the money, and I think the developer challenged us a little bit on, well, you know, Duke, how is this impacting your grid? And, you know, we perform our studies trying to account for certain contingencies, like a facility may be doing something unexpected sometimes, but, you know -- so ultimately they didn't really respond to it.

I think what we learned out of it was that the inverter technology is still maturing. And the whole industry has been talking about this, so that's something we have to keep a close eye on. We've seen inverters do many, many different things that we can't explain. And in some cases if it doesn't cause an impact, then we're not going to kind of go crazy about it, but we are really concerned because we -- we -- the industry as a whole has not done a great job of -- of explaining and providing models to the utilities, and they admit this. Part of the problem is their designs are proprietary, so they don't want to share them out.

So -- so we've learned a lot about inverter technology, and we're just trying to really take those learnings and -- and adapt and move forward from there. So that's kind a very general answer, but, I mean, I think that's part of what we've learned from that.

Q So you couldn't see from that one or learn from that one event anything that lets you see it in advance --

A That --

Q -- with another -- with another farm that's trying to come on?

A Correct. In some cases we're able to do that, and then some cases we're not. That's a great example of where we're keeping an eye out for that sort of thing to happen again. We -- we strike a fine balance between seeing an impact and then saying, okay, like the Campbell Soup event was very concerning, and we were able to eventually come to an analysis that could capture that and -- and then prevent that in the future, and -- and a reasonable one.

And in the -- in the case of this other facility, if that perhaps was an isolated incident and barely ever happens again, you know, we're happy to acknowledge that we're just going to keep an eye out for that and kind of not overreact. But -- so it's a -- it's a fine balance, and these are two good examples.

Q All right.

A (Freeman) I think I'll also add, I mean, when -- when we've looked at some of these facilities and we've put monitoring equipment out there, we've seen disturbances in, you know, your traditional clean sine wave. We've not seen that it's had an impact on, you know, a customer necessarily, but clearly could. I mean, if you see a -- I mean, your ideal is a very clean, you know, sine wave, and when you see some of these disturbances, I mean, it does some crazy things for the -- to the sine wave and, you know. So it's -- it's a challenge to kind of link that to an actual customer complaint, or a customer having, you know, issues doesn't necessarily connect it, either, or -- or even, you know, complain to us.

I mean, this could be simple things like TV, you know, failing or electronic equipment in a house failing. You don't necessarily always know what the cause was. Sometimes it's lightning, sometimes it's the equipment, but very well could be some of these disturbances that we see on the system.

Q Okay. Thank you.

EXAMINATION BY COMMISSIONER MITCHELL:

Q Mr. Freeman, just a few for you. And -- and most of them are follow up on questions that you've been asked a couple times now, but the 500 plus MW that -- that Duke interconnected in 2018, can you tell us, was -- was the majority of that small facilities like the 5 MW facility or was -- was it predominantly large facilities, to the extent that you know?

A (Freeman) It wasn't 50/50, but -- but, you know, we're now starting to see as part of that mix, you know, the larger transmission projects. I'm thinking it was about 200 MW were transmission size projects and the other 300 or so were distribution. I'm looking to Mr. Riggins to confirm.

A (Riggins) That sounds right. I have the notes in -- in my laptop, but I -- I wanted to say 250, 260 in transmission. It was a -- it's a much smaller number of projects, of course, but --

Q Right.
A -- they're larger projects.
Q Okay. And all of that is directly interconnected as opposed --
A (Freeman) What do you mean by "directly interconnected"?
Q Well, connected to DEC or DEP and not within one of your wholesale customer service territories.
A Correct.
Q Okay.
A That's all project connecting directly to Duke, yes.
Q Okay. A few more questions about that $200 million reconductoring project. Is the -- is the large project that will be making the prepayment on that work, is that a -- is that -- is that customer interconnecting under the large generator standard or the small generator?
A It would be the -- the large --
Q Okay.
A -- because remember the SGIP is up to 20 MW --
Q Okay.
A -- on FERC. Right.
Q Okay. The -- there are several figures that

are -- that you used in your direct testimony -- it's Figures 2 and 3 -- and then they were circulated later today as redirect exhibits. Just a very general question. I note that the source data are EIA data.

A Uh-huh.

Q Can you explain why you all used EIA data instead of the Company's data?

A Well, we thought to try and be consistent with, you know, looking at, you know, state benchmarking, that we would use kind of a consistent, you know, report resource. So I think your question is, is our data exactly right? It's what we've -- it's what EIA has picked up from our filing, so it's the same, you know, what they picked up from each state, so we felt like that was probably the most consistent way of doing a comparison across states.

Q Okay. So your -- you don't -- Duke's internal data wouldn't differ materially from --

A Correct.

Q -- what the EIA has reported?

A Correct.

Q Okay. And all of this is direct interconnection as well?

A Yes.

Q Or let me ask it a different way. Is it direct interconnection or does it include some indirect interconnection?

A No. This would be all interconnections connecting up to the DEC/DEP, you know --

Q Okay.

A -- system, not behind wholesale.

Q Okay.

A So the difference there, if you look at Figure 1, the 380 minus the 308, you know, the -- the 72 projects, you know, a significant number of those are -- are likely Dominion, and then there are some that are, you know, behind wholesale.

Q Okay.

A For example, Wilson, I think, has 70 MW or seven projects, I think, connected up on their system.

Q Okay. Okay. Duke has provided testimony on post energization costs that are not -- I guess that are not being recovered directly from interconnection customers. And there has been testimony on sort of cost recovery issues in general associated with the interconnection process. How is Duke recovering cost associated with the stakeholder processes that you all have been employing over the past couple of years, to the extent that you know?

A Well, I assume cost that we can't quantify, you know, and -- and allocate directly to, you know, an interconnection customer, some of it we're trying to collect in, you know, kind of administrative overheads, you know, and then allocate that back out through, you know, through deposits. But a portion of it, you know, we don't have a good mechanism to quantify and -- and recover that other than through, you know, through base rates.

Q Base rates?

A Uh-huh.

Q Okay. Okay. I know that you didn't provide testimony on this issue, but your colleague did, on -- on enhanced scoping that you all propose. And -- and we've talked some today and yesterday about grid locational guidance. And this is just sort of a conceptual question for you. I mean, my -- my understanding, the -- the Commission has changed the -- has revised the -- the interconnection procedures several times over the past couple of years sort of in -- in an effort to unclog the queue, just to use the language that we've all been using, but to -- to make the process more efficient. And I -- I think there has been some eye towards providing more information on the front end of the process rather than later in the process to avoid some of, you know, the -- the time that's expended on projects that ultimately may not be feasible.

I think I heard you say today that even providing additional grid location -- information regarding congestion or constraints on the grid, that projects are still seeking to locate in constrained areas. Did I understand that correctly?

A I'm not sure exactly how I stated -- stated that response, but we see, and I think it's in one of our testimonies, for example, that we've already got connected up on to a particular substation pretty much all we can handle without making a significant upgrade to the substation, yet there are additional -- I think in the one example we gave there's like an additional 13 projects that have proposed to connect up to that substation. I don't have the information as to when those projects came in, to -- to --

Q And that was my --

A -- really kind of get at your question, were they new, but what we have seen, if you looked at my Figure 4 and 5, I -- I think that kind of starts implying that, you know, our message has been, you know, the distribution system, it's getting more challenging to connect up to these rural substations, you know. So you can see that the distribution -- proposed distribution projects have dropped off significantly, and what we've been suggesting is that, you know, to -- to, you know, interconnect lowest cost, most cost-effective projects, the bigger transmission projects would -- would make more sense. So you've seen an uptick in transmission projects and kind of a downtick, if you will, in distribution.

So I think part of what I think you're asking is there has been a positive response in terms of, you know, the messaging, if you will, that we send to, you know, the developer community.

Q I guess my question is that, you know, is -- would additional information as to constraints on the -- on the grid areas of congestion, would that be helpful in continuing to unclog or -- or facilitate the interconnection process?

A I mean, it's -- it's hard to say. I mean, we've -- we have felt like when it made sense, we provided, you know, the grid locational guidance. But unclogging the queue is kind of complex question.

A couple of us were talking at break. I was talking to a couple of the other intervenors about, you know, the -- I called it early on the California Gold Rush in reverse. I mean, if -- if we're offering, whether it's, you know, competitive procurement through CPRE or whether it was offering, you know, a five-year standard PURPA contract, the signals that you provide really drive a lot of the -- the queue itself. And we've seen it in other states, you know.

What, two, three years ago South Carolina had almost no projects in their queue because the standard contract was, you know, 1 or 2 MW and, you know, a five or 10-year term, and it just at that point in time wasn't conducive of, you know, project development, but -- but now in South Carolina with Act 236 and others you've seen kind of an explosion in the queue in South Carolina.

So there's kind of a number of kind of, I'll call them, economic factors that kind of feed into the queue. You see it around the country, that if you're providing the market signals to support, you know, project development, you're going to get a clogged queue.

Q Yeah.

A And we've seen New England ISO. I think they've got like 92 or 97,000 MW in their queue. Our -- our adjacent neighboring company SCANA, last I talked to them they've got 8,000 MW in their queue and they're only a 5,500 MW system. So they've got, what, one and a half times the size of their system. I mean, we're at 14 or 13,000 MW, which is probably less than half, you know, of -- of our total system.

So long answer, but I think there are a lot of factors that -- that contribute to the queue, and unclogging it is -- is going to be a challenge. I mean, if you say no more, you'd probably unclog it, but I don't think anybody supports, you know, supports that position. That's kind of the extreme. You'd unclog it if you said no more.

Q Right. The testimonies given today seem -- I mean, I guess I'm taking away that much of the drag in the -- in the process is on these interdependent projects. And so is that -- is that sort of going to occur going -- is that drag going to persist going forward; because interdependent projects are already there, those requests have already been made? Or is the -- is there -- I'm looking for a way to avoid sort of additional interdependent requests being made going forward.

A I mean, I think we've testified that, you know, that the complexity is increasing, not decreasing, and the interdependency started out as, you know, interdependency being at the circuit -- distribution circuit level, then it went to the substation level, and now it's at the transmission level. So these -- this -- this $200 million upgrade that we're talking about, I mean, there's, you know, roughly -- I've lost track of the number of projects, but there's roughly a hundred projects between North and South Carolina that are dependent on those upgrades. And if we're saying we can't get those upgrades constructed until end of 2022, you know, those projects are going to, you know, be in the queue and be ready to connect until -- till we get those upgrades done. So I don't know. It -- it's a complex challenge for all of us.

A (Riggins) Can I mention one thing as well? I think it's important to know that we don't just study them in a linear fashion so that you just do transmission or distribution. One of the things we're doing today is recognizing that some of these upgrades will cause a project to be 2022 interconnecting, but we'll go ahead and do the distribution part of the study to provide that information to a developer today.

The project might very well not be viable for distribution reasons. We want them to know that so they can make a business decision of whether to wait for 2022 for the upgrade to be built or not. So, you know, we're trying to look at all those components, and -- and so I think in somewhat support of what you're asking for is, you know, how do we provide the information that's available to projects so that we can finish projects that are viable and can be studied and connected and also enable projects to withdraw when that's the right answer.

Q Okay. Well, that's -- all that's helpful. I appreciate that. So one last question, and either of you all can -- can answer this. The -- the enhanced scoping that you all have proposed, I assume that's to provide for more technical information earlier on in the process so that business decisions can be made thereafter. Why not propose that as part of a pre-application process? I mean, why wait until an interconnection request is made?

A I can address that as well. Certainly, we would like for customers to buy the pre-application report, use that to inform their decision on whether they submit an interconnection request. At the same time, in many cases a customer may be interdependent and may have a large number of projects ahead of them, so we were proposing how can we provide this enhanced level of information at a -- in an earlier scoping meeting to inform them of that in the absence of whether they pay to get a report or not.

So we're not saying one or the other. Our hope would be that you get a pre-application report. We provide better information around enhanced scoping meeting and throughout the process so that there's a good flow of information. Our goal is to interconnect projects that can be interconnected and get projects withdrawn that can't.

Q Okay.

A (Freeman) Yeah. We -- we've also done something else that probably hasn't been shared very clearly yet. We've done what I would call a form of grouping studies for projects. We tried to, you know -- I mean, we've kind of implemented this grouping study concept to look at especially distribution projects and whether they are truly behind some of this transmission congestion or not, and we've done it in kind of -- we've kind of formed groups to do that because it was -- created more efficiency rather than studying them one by one. We've tried to do that, to bucket projects that are impacted by congestion and bucket projects that are not distribution projects. So that's helped a lot, provide transparency as to where distribution projects are not going to be impacted by transmission congestion.

So I've lost track of the numbers, but I think in DEP we -- we grouped -- the first group was like 170 or 180 projects or something like that, of which -- or maybe it was like 284, I think, projects; 172 were not impacted by the transmission congestion and 100 were, so essentially there's 170 or so projects that -- that are not going to be -- you know, they're not facing transmission congestion.

So we're trying to think of all kinds of ways we can, you know, help inform and -- and keep, you know, projects moving forward. And most of those projects are projects, to a point we made earlier, that they -- they're eligible for, you know, the PURPA Sub 140, some of them 136, and lot of them 148, you know, so they've got a good viable pass forward as long as the distribution upgrades are not, you know, in that multimillion dollar range.

Q Okay. Okay. Thank you.

A Uh-huh.

Q I appreciate that. I have a few for Mr. Gajda. And some of these are coming from our -- our staff, so they are technical questions, and so I'm -- just keep in mind I'm -- I'm a lawyer asking a technical question.

In your direct testimony you testify about reverse power flows --

A (Gajda) Okay.

Q -- on the distribution system.

A Yes.

Q Can you, one, explain what a reverse power flow is, just so we're all on the same page, and why it's a problem, if -- if it is a problem, and if it's -- if the -- if this phenomenon is still occurring even after Duke has made whatever adjustments it can make to its system to, you know, to react?

A Okay. Sure. So -- so the -- I mean, the basic architecture of the distribution system, frankly, is to distribute power, and so forever and a day, power has flowed in a one-way direction from the substation out to every end-use customer. In that respect it very much resembles many other utilities, gas, water, in that respect.

Reverse power flow can occur in different places in the distribution system only when generators are present, so it can occur at a small net metering customer. And there's a sunny day and there's not much load in the house, that flow will go backwards through the meter and will go -- it may just distribute. That power may just distribute to that individual's neighbors and may not go much further. It all depends on the order of magnitude.

I sometimes give the example of pushing water back up the garden hose. And pressure is actually a great analogy for voltage, which is one of the primary things that we run into in our studies. So, you know, you may have 80 psi at your outdoor spigot all the time. The only way you're going to make that water go backwards is to have some source that can produce more water pressure than 80 psi.

And -- and that's what occurs with, say, a solar farm, is that it is, say, 5 MW, pick any number, it's generating a sufficient amount at its location and that it's making the power flow go backwards up the circuit. Where normally it would always be -- flow from the substation downward, it's -- it's going back up the circuit.

We're managing this in our interconnection studies to a -- to a decent degree. And we study this and our models can account for it. It just does challenge a number of long-held assumptions in how the distribution system operates. So you've -- and I'll just briefly say one more thing. You -- you've heard, Mr. Freeman said a minute ago, that the -- the more optimal location for, say, a utility-scale facility is closer to the substation, and this is one of the reasons. If we know it's large enough that it will push power backwards up the feeder, the closer it is, the smaller the zone in which that occurs, and -- and the lesser amount of the rest of the distribution circuit that is -- that's impacted. Hopefully, that's helpful.

Q And so are you -- is Duke -- are the Duke utilities experiencing reverse power flows on the distribution systems?

A Yes. I mean, on a regular basis. So -- so when we first started interconnecting distributed generators even all the way back to the original PURPA days, you would have reverse power flow on a circuit. And as we've seen penetration increase, the next thing that happened is then we saw reverse power flow through the substation on to the transmission system.

Q Okay.

A And so -- and we are experiencing that in dozens and dozens of substations in DEP, for example.

Q Back on to the transmission system?

A Back on to the transmission system. We've made clear in several, you know, places where we've discussed this that -- and some of these transmission constraints that have been discussed, that it's a -- it is a key point that we don't even have to have reverse power flow at the local distribution level for the transmission system congestion to occur. So I think that's actually a key point because the transmission system is modeled with all of the loads and generators that are present, and all it has -- all that has to occur is a reduction in flow even in some areas for the flow patterns to change on the transmission system and a -- and an impact to be seen on the transmission system, so I just wanted to mention that.

Q Okay. Okay. Shifting gears on you just a little bit, in your direct testimony you provide a chart listing dates that -- that the Company hosted technical meetings --

A Yes.

Q -- with members of the solar industry. And one of those meetings that occurred in December of 2016 -- it's on page 51 of your direct if you want to -- if you want to --

A Thank you very much.

Q -- reference it. There is an entry on that chart titled "Addressing line voltage regulator policy, DEP's Distribution System Demand Reduction Policy and advanced study development update."

A Yes.

Q Can you provide just a very brief summary of what was discussed with regards to DEP's distribution system demand reduction program and tell us whether the integration or addition of solar facilities on the distribution system has impacted that DSDR in any way?

A Yes. I'll -- I'll attempt to be brief. DSDR is an extensive system, but I think I can meet that.

The DSDR system, by its very name, was intended to replace the peaking capacity of several combustion turbines, and so it is a system by which our energy control center can dispatch -- we tend to think of the term "dispatch" meaning dispatch a generator to turn on to serve load. In this case we can dispatch the system to take roughly 300 plus MW off of the distribution system, so it's a demand response system in that -- in that respect. And it's done by reducing voltage across the entire distribution grid. I kind of call it the big red button. But when the button is pressed, we can reduce voltage across all of the grid, thereby taking that 300 MW off.

It's deployed as a -- as a -- as somewhat as a peaking generator is, which means it's only deployed when that peaking resource is needed. When that peaking resource is not needed, that voltage, then, is -- is at its starting point, which is typically fairly high in the plus or minus 5 percent voltage range that we're required to serve customers with. I've referred to R8-17, the Commission regulation. And so we -- part of the installation of this system was a -- a distribution management system with a lot of brain and algorithm in it, but we also installed a -- a number of regulators, capacitor banks, all to help regulate voltage. So our normal goal is to keep voltage on the distribution system at a relatively flat profile and relatively high in that what I call regulatory range. And -- and by doing so, essentially that's kind of water in the tank, then, that allows us to then drop voltage when we need it to -- to dispatch the system.

From its -- in regards to impact and relation to solar development, there is a notable impact which has been -- which was talked about in this meeting. So I think at this meeting we described in general what I've just described to you. And I'm -- I'm -- it's been awhile, but I'm sure that I described the fact that voltage operating high in this regulatory range essentially means that when a -- a -- say, a utility scale solar farm interconnects to the system, any -- actually, any generator on the distribution system will cause voltage rise, back to my kind of water analogy. So it will cause -- cause voltage rise.

Well, there is a certain amount of -- some people use the term headroom between the -- what the voltage is and that top end regulatory limit of 5 percent over, or 126 if you want to reference the outlet, and whatever that delta is, is what can be -- is the room that we have essentially to see voltage rise to accommodate the -- the facility.

In a -- in a utility system that does not utilize DSDR, on average you will perhaps have -- and it's an unquantifiable amount, but you will have perhaps greater amounts of headroom along your circuit in certain areas because you're not seeking a Volt/VAR system that is -- that is trying to, you know, kind of keep that water in the tank and hold it high.

So if that helps, I think that's the -- that's the primary impact that -- that impacts solar developers and solar farms.

Q Okay. And is my understanding correct that there is not DSDR on the DE system at this time?

A On the DEC system?

Q Yes.

A That's correct. I -- I believe it's accurate that the -- the Company is wanting to maintain kind of flexibility to determine what sort of -- of Volt/VAR management system, if any, that it might want to deploy in DEC. A DSDR system is a -- I would say a subset of what the industry calls an IVVC, integrated Volt/VAR control system, and it does what I've explained that it does. There are other types of systems that -- that can do other things, and so, you know, I think it's -- what I'm aware of is the Company's current status is they're kind of in a, you know, evaluation phase on what sort of Volt/VAR management system might make sense in -- in DEC.

There's a lot of kind of additional kind of points and benefits that come to installing a system like this. Certainly, in DEP we've seen that. I mean, one of the benefits to keeping voltage actually high and/or just managing voltage very well and having all that telemetry is there's actually a recognized impact to transmission system stability because you have capacitor banks on your -- on your system. And you're minimizing -- sorry, we're getting very technical, but you're minimizing VAR flow and reactive flow. That's a key element in maintaining a very stable power system.

So we're trying to look to DEC to see -- maintain flexibility on what we want to do there in the future, I believe.

Q Okay. Okay. So do you -- does DEC apply -- do you all apply the same policy in DEC that you would apply in DEP or that you do apply in DEP?

A Around this LVR policy?

Q Yes.

A That's correct. And -- and in the Method of Service Guidelines, we actually document in there in the introductory paragraph kind of three primary elements as to, you know, why this policy is so important, and one of those three is the existence of a Volt/VAR management system. So it's -- it's, you know, key to your questioning, I think, that, you know, the other elements kind of get into what we've discussed about how important it is to have these utility-scale facilities close to the substation.

A key element of distribution system architecture like I've been describing is -- is we use these -- these voltage regulators, electromechanical devices, to regulate voltage. These devices are very effective and they work great and there's typically one of them at the substation, but then, of course, there's occasionally one or more out on the distribution circuit. We -- we refer to those as regulated zones.

The nature of how these operate, they operate kind of slowly. They're electromechanical. They're proven technology. Every utility uses them. One key element is that they are designed around the fact that distribution load changes relatively slowly on an aggregate basis, so from minute to minute, the old joke about the little boy playing with the light switch. You know, we don't see that in aggregate up at the regulator. What we see is just load changing. You know, when -- when more little boys wake up in the morning and start doing that, perhaps we start to see a little bit more, but it changes relatively slowly, and these pieces of equipment are designed to adapt to that very well.

And we can manage utility-scale solar, utility-scale facilities like this in that first zone of regulation outside of the station pretty well. When you start getting subsequent zones, it's just a -- you would find -- I think any distribution utility engineer would tell you that if -- if, you know, if you wanted to pick the location on where to -- to have -- have facilities like this and be able to manage them effectively long term, having them in subsequent down regulation zones, you know, second -- second zone and further, it's -- it's -- there's a number of reasons, but one of them is just the operation of these devices. It just -- it's just not a sustainable practice to have facilities that may turn on and off or very large facilities further down like that.

Very much like an industrial plant that may need a, you know, very stable supply of voltage. Maybe they have a critical process. Oftentimes those facilities are through -- through some combination of the -- the Company or the -- or the plant site development themselves, you will find them often very close to a substation for similar reasons.

Q Okay. And you sort of -- you raised an issue for me. You -- you testified earlier today, I believe on cross examination, about a retail load shift that occurred post-installation of a solar facility.

A That is correct.

Q And then you all had to do some -- some construction work to accommodate, I guess, new retail load.

A That -- that's correct.

Q Was -- was it -- were the costs associated with that work that you all had to do, were those borne by the new retail customer?

A The -- the costs were borne as just a part of -- I mean, subject to check; I'm 99 percent sure of this -- they were borne by just our overall ratepayers as part of a -- a distribution -- you know, just -- just our overall kind of, you know, capital improvement.

Now, I mean, typically when a new retail customer shows up, if -- if they -- I know at least in DEP if they've caused enough of an impact and we have to do a sufficient amount of construction, I believe there's like a three-year revenue credit calculation that's done, and then -- and then -- and potentially they may have to -- under our file line extension plan they may have to contribute to part of that. I -- I have to admit I'm not -- I don't know if that was -- had to be employed here or not, so I'm -- I'm kind of running with the assumption that it did not have to be employed here, subject to check, but...

Q Okay.

A Yeah.

Q Okay. Okay. Mr. Gajda, I think that's all I have for you. Thank you very much for your responses.

A Okay.

Q Mr. Riggins, just a few for you. We have one question about staffing. There's been testimony today about staffing, that -- that Duke has increased in an effort to continue to manage the interconnection process. Can you tell us whether, to the extent that you sort of have a -- a general idea, whether this staffing is primarily contract labor or is it primarily permanent employees?

A (Riggins) Primarily permanent employees. The one exception is the -- the study teams for the distribution studies. I think there's 40 listed on there today. Those are contract employees. But they have -- our distribution team has permanent employees that work and interface with that team.

Q Okay. So the 110, I'm -- just so I don't have to flip back to the chart, but the 110 is just study team? That's not -- doesn't include additional employees used in the interconnection process?

A The 110 that we referenced would be employees that are dedicated, and then study team would be over and above that. So I think the question earlier today had to do with was it 140 or 100. So I think it's 100 employees, and then we have contract engineers that we're able to ramp up and down as we need to.

Q Okay. And can you just explain why Duke would hire contract as opposed to permanent employees in this instance?

A Sure. So, you know, the nature of the studies, I guess, could -- can ramp up and down, so, I mean, we don't know today if we're going to get 10 new requests next year or if we're going to get a hundred, so I think part of staffing, whether it be interconnection or just routine work, is to engage a certain number of contract workers and a certain number of employees. We -- you know, we follow a similar model. And I -- I was not engaged at the time when we brought the contracts before us on, but we recognize we didn't have enough employees engaged at that time to do that work.

As -- as John has said before, in many cases, you know, a few years ago it was somebody's secondary role. So we now want to engage these contractors, and it's their -- they're dedicated to that work. It's their primary responsibility.

Q Okay. There's been testimony, again, today on post-energization cost. I think I asked Mr. Freeman one of these questions, but you testify about them specifically, and I think some of the examples you give are regulatory support, legal support, small customer meter changes or meter charges, maybe, and dispute resolution process. To the extent that these costs aren't being recovered from interconnection customers, has Duke given thought to how to recover these costs going forward other than through general rates?

A Well, we've had conversation internally about how there may, you know, be a mechanism either applied to the rate so that there's an ongoing cost to maintain the projects that we're building today. I don't think we have anything specific on the table, but there have been discussion I know among our team as to how we might do that going forward.

As those costs -- as we add more projects, of course, those costs are going become larger relative to today. Almost all of our costs are interconnection focused and on the studies that we're performing.

Q Okay.

A (Freeman) And a couple of other thoughts around that, one is, you know, within the PPA tariff, you know, there is a fixed customer charge there that's designed, as I understand it, to cover billing and some of those aspects. But, I mean, essentially we're building a couple new classes of customers. We've got the large, you know, utility scale projects. They are creating cost in our, you know, energy control center, in our distribution control center to switch and operate those. You know, there's no real cost recovery mechanism for -- for those costs.

But even the small projects, you know, we've now got -- I've lost track of how many thousands of net metering, you know, typically residential customers, but that class of customers, through our renewable service center, which went from five part-time employees back in like 2012-ish to about 24, 25 employees today, part of that cost is kind of managing the ongoing questions, you know, around billing, or my facility isn't performing like I was -- like I was -- like I was told it would -- you know, it's not saving the kind of money that I should have saved. And we're getting a lot more questions ongoing, you know, to support these projects and answer those questions.

And, of course, they come to Duke, which is what we would hope they would do and expect that they would do. But there is no real cost mechanism, you know, recovery mechanism for those other than through your, you know, your residential, you know, rate tariff or through the PPA tariff.

So yeah, I mean, it's a good question, that we're, you know, we're kind of recognizing these costs are increasing and the question is, you know, how -- how should we recover those costs in the future?

Q But the Company is tracking those costs?

A Generally, yes. We're -- we're tracking, you know, those costs as best we can.

Q Okay. Okay. Mr. Riggins, back to you. Timeline enforcement mechanism. IREC provides a recommendation regarding a timeline enforcement mechanism revision to the procedures, and I -- I understand Duke's response through your testimony to that recommendation. But can you -- can you tell us, should there be any consequences for the Utility's failure to meet prescribed timelines when it is the Utility's -- I hate to use the word fault, but when it's within the Utility's control and it fails to meet that timeline?

A (Riggins) It's a difficult question because it's, I think, hard to determine fault. We've talked a lot about complexity of these studies. We've talked a lot about the challenges that we're receiving and the number of delays that are incurred. So to a degree that you could accurately calculate the number of days that the project is actually in study and compare that to the time frames, I suppose, but it -- it's difficult with the volumes that we're dealing with today.

And, you know, we've said it lot, but I think we're all very proud of the fact that we have connected a lot of projects. You know, if you look at the throughput, it looks like the clog continues to be there, but the throughput is happening. There's just a lot of projects that come in and there's a lot of projects that get studied and interconnected. So the 537 MW that we connected this year is consistent.

I -- I think it's going to be different to quantify where does the -- sort of the blame lie on these projects that are in queue, and unless we can really get that better defined. And I go back to Gary's testimony earlier as, well, the comment about, you about, we -- we can finish them in the time frames. The answer will be different, right? We would not be as accommodating and creative maybe as we have been in trying to connect projects and to integrate as many renewables as we can into the system if there were some disincentive to being accommodating, which I think a timeline enforcement mechanism would do.

Q Okay.

A (Freeman) I would also add that, I mean, there's this -- this, you know, balance that we're obligated, you know, to kind of manage, and it goes back to some of the questions, you know, around, you know, incentive mechanisms for us. I mean, if there's a, you know, kind of a financial penalty imposed on, you know, my team, I mean, you're incenting us to go ahead and just connect those projects up, and potentially -- I'm not saying we would -- but you're starting to incent the potential that you would just ignore the, you know, the -- the study and going through the process to ensure that we're maintaining that reliability.

So I just -- just worry about, you know, kind of, you know, the -- the signal we would even be sending to employees because there is a balance to what Mr. Riggins was saying and to the overall balance and obligation that we have to ensure reliability.

Q Okay. Thank you.

COMMISSIONER MITCHELL: I have nothing further.

CHAIRMAN FINLEY: I have a few questions.

EXAMINATION BY CHAIRMAN FINLEY:

Q Gentlemen, one of the things we as a Commission hope to accomplish in this process is to unclog this queue, you know. You know, state leaders want more solar. A lot of people complain about there not being enough solar, the percentage of solar in the state is too low. We've had a lot -- I've got, what, several inches of testimony here that have been filed by various parties. And help me if I am misconstruing this, but I have not, to my own satisfaction, heard about the silver bullet that's going to enable us to -- even if we -- even if we took all these suggestions about reducing the time for this or the complexity of that, unclogging the queue, am I missing something here?

A (Freeman) No. I think your observation is, you know, kind of dead on. There is no real silver bullet, but I think we are, you know, making progress. For example, you know, the distribution queue was the primary, you know, kind of clogged queue. I mean, we're not seeing that many distribution projects going forward. We've probably got four years left of getting those projects, you know, kind of through the, you know, the -- through the process and interconnected. But I think the hope would be that -- that, you know, we'll have a much more kind of manageable volume of distribution projects.

You know, the small net metering projects, I mean, those are not that complex, and like we've testified, I think we're -- we're -- there is no real queue issue with the small projects. The challenge will likely be at the transmission level, but I think as we, you know, either kind of manage that through CPRE and kind of through a managed approach, that will help. And I think if we can move towards, you know, kind of this cluster study concept where you open a window -- you know, as FERC has described, if you're ready to connect -- I forget that exact term they use, but if you're ready to connect, you know, enter into the -- into the window, we'll move you through, and there's some -- some promise even around moving to the cluster studies. But that's not one silver bullet. That's just a number of pieces that --

Q I understand the cluster study. That hopefully will be a -- a major step forward that will allow us to reduce the queue, and I understand the CPRE is intended to help there. But what I'm hearing is incremental steps as opposed to something fundamental that's going to change this queue because of the length of these projects, short of reconductoring your system, so that you can move power from the distribution piece of it back some other direction. Am I wrong about that?

A No. I think -- I think you're right, but, you know, the -- the other pieces we talked about, you know, the Power Purchase Agreement itself.

Q I'm not blaming anybody about that. I'm just --

A No. I know. I mean, but it -- but it's even that, you know, that, you know, kind of the message to the market. I'd exaggerate and say if you -- if you signal the market that you're open for business, I mean, projects will come, and they will, you know, enter the queue. And, you know, there's -- I mean, gosh, I go back to the 2006, 2007 time frame when we put, you know, various incentives in place and nothing happened, nothing happened, nothing happened, and all of a sudden in 2012, 2011 all of a sudden it just, you know, exploded on us. I mean, a lot of it is driven by, you know, project cost and -- and, you know, what -- you know, what the, you know, the PPA terms and rates are. But that's just kind of another component into that no silver bullet. I mean, you need a gun full of, you know, blanks or bullets.

Q I understand. But when -- the suggestion about, you know, doing away with the fast track and moving more things to the supplemental and how many FTEs you have for the transmission project, assume hypothetically that President Good told you folks bear no expense. Hire all the people you need. Buy computers that can allow you to use intelligent design, you know, artificial intelligence. Spare no expense. How much -- how much would additional personnel and additional resources help us move along and speed this process up? Hypothetically, now.

A Hypothetically. I guess one thought is, you know, a lot of those resources just don't exist. I mean, we're -- we're struggling to identify qualified construction crews to even do the work. A lot of our discussion here has been about the study process. Well, it's like long process. If you unclog the study process here, then you need, you know, gazillions of engineers to do all the design, and then you need gazillions of, you know, contractors to do the work.

And -- and we've brought in contractors from, you know, pretty much all over the East, you know, the -- the eastern part of the, you know, the system from Mississippi over into the system to try and, you know, support construction, but they just don't exist, and it takes four to five years to even, you know, train, you know, a lineman to do line work.

So I don't know. I mean, one, it would take a long period of time to kind of build up that resource base and, you know, it would take, I don't know, thousands of -- of people between, you know, kind of each -- each step in the process to get there.

Q Okay. Well --

A I know that's not a very good answer, but there's so much in the process --
Q I understand.
A -- and -- and, you know, even the construction side. I mean, that's what we're seeing now with the -- the upgrades required, you know, this $200 million worth of upgrades. We're planning to assign nine crews to do that work. We can only take that -- you know, those lines out of service in the spring and the fall. There's like two 12-week windows that we could do the work. Nine crews is all we can find to put on that project because the pressure is, you know, on us to get that work done as quickly as we can. And that's the -- I mean, never say it's the best you can do, but that's reasonably the best we can do is identify nine crews to do that work.
Q Yeah.
A They just don't exist.
Q All sorts of suggestions here about things that could be made and improvements that could be made or make a little improvement here, little improvement there, you know, issues about letters of credit versus bonds and that type of thing --
A Which, remember, we thought --
Q -- which they're all -- I don't -- I don't mean

to minimize any of that stuff.

A Yeah. I remember we thought during the 2015 interconnection docket that increasing the deposit would reduce a number of projects out of the queue. I mean, if it had any impact, it was miniscule.

Q But what I'm -- you know, maybe I'm missing this, but what I'm coming to conclude is that these things improve the process incrementally, but not with great strides.

A Right. And just look around the country. I mean, nobody has found the silver bullet. I mentioned New England. PJM has got like 70,000 MW, MISO probably 50,000 MW, Public Service of Colorado 23,000 MW in their queue. The only success story we've seen that I can think of is Public Service in New Mexico where they had 10,000 MW in their queue. These were not PURPA projects trying to sell to the New Mexico utility. They were trying to sell into the Cal ISO, and Public Service in New Mexico was successful in moving from a sequential process to a -- a cluster study process, and they now report that they've got about 1,000 MW in their queue. So that's a success story, but those are big projects, big wind, big solar projects, not lots and lots of -- of little projects. But, you know, I mean, that's probably the only real success story that I can, you know, kind of share.

Q All right. Let -- let me ask a few questions the staff has assigned me to ask, five or six. Ms. Duffley is back there smiling at this.

How many fast track projects that failed the initial screens have had to go through the Section 4 full study process instead of supplemental review?

A (Riggins) I think we captured that question or something very similar earlier.

Q We may be duplicating ourselves, but if you'd --

A Yeah.

Q -- give me the answer, please.

A So we have that captured somewhere. Can you ask the question again? I'll write it down.

Q Yeah. How many fast track projects that failed initial screens have had to go to the Section 4 full study process instead of supplemental review?

A Okay. I don't know the answer. We'll have to follow up.

Q Okay. And why would -- why would they fail and have to go to supplemental review, just conceptually?

A Why would they have to go to Section 4 instead of supplemental review?

Q Uh-huh.

A So, again, supplemental was set up so that if a project fails fast track and we think that there's a reasonable amount of effort that could get them approved without full system impact study, we keep them in supplemental. Otherwise, they go to full study. So there are a number of reasons LVR and those kinds of things drive them to full system impact because you have to do lots of additional work. And the idea is to keep fewer projects that require lots of work down in that expedited process.

A (Freeman) I'd also add that, you know, fast track eligibility is 20 MW -- I mean, 20 kW to 2 MW. So generally what we see is the -- the larger projects, the 1 MW to 2 MW size projects pretty much all go to Section 4 full study.

Q And do you -- do you inform the ISC of the reasons as to why you make the decisions that you do on this area? Do you communicate your reasoning there?

A (Riggins) Yes. And part of the communication that they get saying that they failed fast track and either we recommend supplemental or system impact would provide some rationale for that. And if we don't provide it proactively, we'll get the question and we'll answer it at that time.

Q All right. On page 18 of Witness Auck's testimony she testifies that the current eligibility limit of a 10 -- of 100 kW -- of 100 kW is too -- too conservative, which may cause small net metering projects to be sent to the Section 4 full study process unnecessarily. Can this happen?

A (Gajda) Chairman, this is, I believe, specific to the eligibility table for 5 kV distribution circuits. As I recall, I think -- I think IREC was advocating a move from 100 kW to 500 kW, and this was for -- specifically, this would be for facilities that are greater than two and half electrical miles from the substation. And when Duke really took a look at that, we have a -- that's an older type of infrastructure that really dates from mid 20th century, but we still have circuits that operate pretty well like conventional distribution. They're just not 12,000 or 23,000 volt. They're 4,000 or 5,000 volt.

We took a look at that and -- and we have a -- I think DEC has roughly 180 or so circuits like that out of its 2,500 circuits. It's a small number. Literally the only reason we oppose that is we kind of termed it as nonsensical because the -- the average circuit length of a 5 kV circuit is about a mile and a half, and that's just -- this is the physics of voltage drop and capacity. So it -- this would -- this would barely impact any customer, because to have a facility greater than 100 kW at that location, that just kind of functionally doesn't -- wouldn't exist. So we just felt like it didn't -- didn't make sense from just a -- just a raw physics impossibility perspective to change a standard just to see it conform with the FERC S chip or with some other states.

Q Okay. When Ms. Auck states on page 4 of her testimony that Duke is aware of 160 pending storage projects and that most will be non-export facilities, IREC obtained this information from Duke's response to Data Request Number 1-5. And I think in looking at that data request, at the bottom it's on -- it says the only facilities proposing to export are the 31 utility-owned and third-party owned utility solar-scale facilities.

Can you -- can you discuss those projects in a little bit more detail, the ones that export? And I've got --

A No. I think I've got it here.

Q I've got the data request if you need to look at it.

A I'm sorry. I didn't hear the number, the data request number.

Q It's 1-5. I've got it here if you want to look at it.

A Well, you've got it there, Mr. Freeman. All right. Just a moment, Chairman. I'll take a look at this.

Q Look at the -- look at the sentence that's at the bottom of the page there 17, the only facilities proposing to export are the 31 utility-owned and third-party owned utility scale solar facilities.

A So I believe -- now, I didn't specifically personally respond to this, but I can see from the -- from the Duke response that it says here, you know, Duke has received notification of over 60 customers that have ordered residential energy storage. So -- and -- and, you know, so those -- I mean, there's one manufacturer out there that's very popular who makes a residential energy storage device, and so we've seen a number of customers avail themselves of that.

The -- if you're asking about my familiarity with the last sentence there, the 31 utility-owned, I -- I don't know. I can't speak to my familiarity with that.

I don't know if the other witnesses can.

A (Freeman) I'm speculating a little bit, but the 31 projects may be those original DEC solar projects that were brought online back in like the 2009 time frame. I thought that was like 28, but that's my only correlation with those because I'm -- otherwise, I'm subject to check.

Q Do you know -- do you know how -- if those are the projects, do you know how they fit into the interconnection process?

A Those original projects?

Q Uh-huh.

A I -- it was, I think, before all three of our time, but I assume all -- all of those projects went through the interconnection process back during that time. These were all back in the 2009-ish time frame when I think we came before the Commission asking for recovery of those investments as part of our, you know, research and development of solar back then.

Q Maybe you can provide us with a late-filed exhibit that will verify if those are the projects that we're --

A Sure.

Q -- talking about, a little explanation of that.

A Sure.

Q What percentage of the current queue participated in the CPR process, if you know?

A A percentage. Gosh. I -- I don't have -- I mean, I think, you know, the -- the impact administrator has filed, you know, at least a report. Off the top of my head, I can't remember exactly what the numbers were. It was like 3,000 MW, roughly, of -- of the 13,000 MW that -- that participated. I don't remember the exact number. I'm sorry.

A (Riggins) I certainly don't have the exact number, but I can tell you from the review I saw there were very few distribution projects that bid in, and since most of the queue is distribution projects, I'd say on a percentage basis it's going to be a small number. Majority of the projects that bid were transmission projects.

Q And to what extent, if any, is that going to -- we've talked about this a little bit already -- clear the backlog in the queue?

A I don't know to what extent it's going to clear the backlog in the queue. Again, the intent with CPRE was to get the -- the bids -- get projects in better locations in terms of available capacity on the system and at the right price. I guess there is some potential that if some of those projects get interconnected and if there were upgrades involved, it may create some capacity that could sort of fall to the others, but I don't know of any direct result that's going to unclog the queue as a result of that.

A (Freeman) Want to also keep in mind we're soliciting 600 MW in DEC and 80 MW in DEP, so that's still a small portion of the entire queue.

Q Okay.

CHAIRMAN FINLEY: Other questions? Commissioner Patterson.

EXAMINATION BY COMMISSIONER PATTERSON:

Q I just -- I've just got one or two sort of context questions. Is every project in the queue viable?

A (Freeman) I guess you've got to kind of describe -- you know, define the word "viable." I mean, to us every project in the queue is a serious project that is expecting to interconnect to the grid, so we treat every one of them as viable. It's not really our decision as to whether it's viable or not. We'll provide them, you know, upgrade cost and they'll determine whether that project is viable or not.

Q And in your experience, of all of the projects that have been in the queue over the years, what percentage of them actually get built?

A I'll answer the question maybe this way. I mean, I think, you know, when we look at the total queue and what's ultimately been, you know, requested in interconnection, and I'm thinking utility scale, I'm -- I'm estimating a little bit, but roughly a third of the projects are withdrawn for any number of reasons. And I assume in most cases they determined that it wasn't viable or couldn't get permits or couldn't get land leases, you know, whatever. And roughly of that number, what we've seen that have actually been connected is about a third, so it leaves kind of another third that are still in the queue. So I'm -- I'm simplifying, but it's roughly a third withdrawn, third have been connected, and a third are still in the queue.

Q And you mentioned market -- I think I get the exact of it -- maybe market signals --

A Market signals.

Q -- yes. Yeah. And I know that since I've been on the Commission, those -- those Monday morning requests for certificate, those things went straight to the moon.

A Right.

Q What were those market signals that caused

North Carolina to be such an attractive place to --

A Sure.

Q -- propose solar development?

A I mean, it was no one thing. I mean, the state, you know, adopted, you know, tax incentives, property tax abatement, REPS. You know, those are part of the market signals. Then the standard contract, which was a 5 MW contract -- you know, 5 MW size limit, 15-year term, was probably the -- one of the bigger incentives.

So back early on, especially when natural gas prices were so high, you know, we were still coming out of the 2008, 2009 kind of gas spike, you know, those avoided cost rates for those 15-year term projects were up in the $80 a Mwh range, you know, since -- and that was Sub 136-ish, 140 dropped down into the 60, $65 range, 148s dropped down into the upper 40s range, and I think our new avoided cost is even lower than that. That all contributes to the market signals.

I mean, I think a lot of us thought when the tax credits would -- would roll off that we'd see a drop, but, you know, solar costs have continued to come down to where those -- those particular market signals were effective. It kind of jump started the market, but I think we've seen now that they're -- they're not --

they're not needed.

Q So North Carolina is still going to be a very attractive place for solar development for --

A Well, I think we're --

Q -- the foreseeable future?

A -- hoping so, yes. I mean, that's the idea behind House Bill 589, you know, in providing rebates for small projects, committing to the market that we're going to purchase, you know, a significant amount of generation through the, you know, through the CPRE program. So, yeah, I think the hope is that we will continue to attract renewable.

Q So the complexity will continue to grow?

A I think -- yes. I think we've testified that the complexity of continuing to connect up projects will, you know, the complexity will -- will go up.

Q Okay.

COMMISSIONER PATTERSON: That's all I've got. Thanks.

CHAIRMAN FINLEY: Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Just a quick one because we want to get you out.

FURTHER EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q The -- I asked you earlier about the battery --

when a battery is proposed or requested with regard to an existing solar installation. Has Duke given any thought about how those will be processed if you start to receive those? Will they -- will they be treated as a new request? Do they start all over? Do they change position in the queue? Will they be treated as a material modification? You know, what kind of process is around those battery requests?

A (Gajda) So just to clarify, you mean request to add storage to an existing solar facility?

Q Yes.

A Whether -- like an existing one that's already operating?

Q Yes. And -- and possibly just one that's waiting in the queue, too, if you've given thought to either or both.

A Yes, certainly. So if it's in the study in the queue -- and -- and this is addressed in the -- in the -- in the redline in this proceeding -- if it -- if the system impact study has not begun yet, then -- then essentially there's, you know, there's latitude there to add that storage facility to the request because we haven't begun the study yet. And so it doesn't really kind of break anything, in a sense. And so -- so in that

-- and to that extent it won't be -- it will not be judged a material modification.

Once the study has begun or if the facility is already online, that's where an, in general, addition of storage would be a material modification for the reasons we've discussed. It's just because the -- the number of unknowns. There's really, you know, too many unknowns, the mode of operation, the time of day, you know, a number of items, and -- and it would be irresponsible of us to -- to not require that it be studied.

With the structure of the standards the way they are, if you're in the study phase or if you're currently operating, there's -- there's a -- not really a structure for what I would call a slang term I'll just call restudy. If you're in the study phase and you're being studied, then it really requires that -- that it be studied, you know, in an integrated fashion, which means that -- that that facility would have to go to the end of the queue.

If you're currently operating, then you want to add storage, you can continue to operate your existing facility. That would then just be treated as a new interconnection request. It would be very similar to if a 5 MW solar facility wants to suddenly be a 10 MW solar facility. You can continue to operate the 5 MW facility while you put in an interconnection request for -- for an upgraded 10 MW.

Q So -- so there wouldn't be a different designation for storage category, and they would just go right back in with respect to adding that storage, starting over, waiting in the queue, waiting for the study to be done and not be able to take advantage of -- of the storage opportunity?

A I mean, yes, because the storage facility -- because the -- the -- the nature of the storage operation has to be -- has to be studied. That's correct.

A (Freeman) And I'll just add that, I mean, it's easy to assume that all storage is the same, but, I mean, what we've seen is that, you know, you can have a one-hour discharge battery, a four-hour discharge battery, you know, even the -- the technologies are changing, so we've got to understand, you know, what kind of solar -- or solar -- storage facility that is being proposed. I mean, the size of it will have a big impact. Is it 1 MW connecting to a 5 MW solar? Is it a four-hour discharge? It is a two-hour discharge? All those kind of things, you know, will make that battery perform much differently.

CHAIRMAN FINLEY: Questions on the Commission's questions?

MR. JIRAK: Just a couple real quick, if you don't mind. Sorry, Gary. I'll be as fast as I can.

CHAIRMAN FINLEY: He's your lawyer.

EXAMINATION BY MR. JIRAK:

Q Just a couple of clarifications. I'll make this very quick, Gary. I promise. One issue that came up earlier where there was a question from Commissioner Brown-Bland about whether Duke checks small projects for Report of Proposed Construction. Jeff, I think you got some information on that. Could you just update the Commission briefly?

A (Riggins) So our team did confirm that we're requiring the Report of Proposed Construction on all projects under 2 MW. And in addition to that, we provide a lot of information on our website for customers that might not understand that as to how to make that filing, how to get that information. So we have to have that docket number on all requests before they would be deemed a valid interconnection request.

Q Thank you. Mr. Gajda, briefly, we -- there was a discussion regarding nonstandard technical solutions when we discussed that with Public Staff, the -- the general issue of nonstandard technical solutions for accommodating interconnection of solar projects.

A (Gajda) Yes.

Q Do you have any recollection of some pending Notice of Disputes that involve developers asking us to consider nontechnical solutions, such as moving regulators or adjusting voltage settings?

A Yes, yes.

Q Okay. So those are current -- we are currently dealing with -- developers are asking us to implement nontechnical standard solutions, and those are being discussed in collaboration with Public Staff and we're --

A Yes. That's exactly right.

Q -- trying to figure out a path forward there?

A That's right, yeah.

Q Okay. And just one final question. We had just general discussion about the interconnection queue and the fact that it continues to grow despite our -- our best efforts and if there is any silver bullets to that. Mr. Freeman, I won't ask you to turn there, but I think you might recall in your testimony you -- you gave some -- in your direct testimony some general stats about the average number of interconnections we've achieved year over year since 2015, and that average number is over 600

MW per year. Do you recall that testimony?

A (Freeman) I -- I don't recall the exact 600 number, but I did provide a chart that shows, you know, interconnections year over year ranging from, you know, 500 to 700 MW, yes. And you can assume that the average is about 600 MW.

Q That's 2 MW and over. And to put that in perspective, what Duke has achieved on -- on an annual basis actually exceeds -- the ninth leading state all time, New Jersey, exceeds what they've interconnected in the whole history of their interconnection process. So what we achieve in a year dwarfs what other states have achieved, and New Jersey is in the top 10. So do you recall that part of your testimony?

A I -- I do, and that's one of our, you know, kind of main messages is, you know, look at the results, and we're proud of what we've done to achieve those results.

Q And -- and yet despite the amount of interconnections we're achieving, in 2017 in your testimony, you testified that 3,000 additional MW entered into the queue in just one year alone. Do you recall that?

A Not specifically I won't, but I'll take your word for it.

Q Thank you. And just as a matter of logic, it's very difficult to reduce the queue when despite your nation leading success interconnecting projects, year over year the amount of -- of interconnection requests entering the queue vastly outnumber the amount of interconnection -- interconnections that are even remotely possibly to achieve in a year?

A I would agree.

Q Okay.

MR. JIRAK: I have no further questions.

CHAIRMAN FINLEY: All right.

MS. KEMERAIT: And very briefly.

CHAIRMAN FINLEY: Well, we usually want you to go first. It's their witness, but be -- be brief.

MS. KEMERAIT: Okay.

CHAIRMAN FINLEY: But next time when you're called on, ask your question.

MS. KEMERAIT: Okay.

EXAMINATION BY MS. KEMERAIT:

Q In response to a question, Mr. Gajda, from Commissioner Brown-Bland, you responded that batteries can have different sizes and can discharge at different times, but as I asked you previously, there are limiting controls that can be put in place that can prescribe the output, the -- the amount of the output and the -- the times at which the -- in which the output would be discharged; is that correct?

A (Gajda) Yes. That theoretically is true.

Q Okay.

MS. KEMERAIT: That's all the questions I have. Thank you.

CHAIRMAN FINLEY: Okay. Very well. Thank you, gentlemen. We will accept into evidence the direct and supplemental exhibits of the Duke witnesses, the cross examination exhibits of NCSEA and the Attorney General, and the redirect exhibits of the Company. And you may be excused.

(Whereupon, Gajda Exhibit 1, Rebuttal Exhibits JWG 1-4, Rebuttal Exhibits JWR 1-3 and 5, Corrected Rebuttal Exhibit JWR-4, NCSEA Duke Cross Exhibits 1-4, Attorney General Duke Panel Cross Exhibits 1-3, DEC/DEP Gajda Redirect Exhibit 1, and DEC/DEP Freeman Redirect Exhibits 1-2 were admitted into evidence. The confidential pages of Corrected Rebuttal Exhibit JWR-4 were filed under seal.)

CHAIRMAN FINLEY: So Dominion?

MS. KELLS: Dominion calls Michael Nester to the stand.

MICHAEL J. NESTER; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MS. KELLS:

Q Mr. Nester, would you please state your name and business address for the record?

A Yes. My name is Michael J. Nester, and my business address is 200 Vepco Street, Roanoke Rapids, North Carolina, 27870.

Q And by whom are you employed and in what capacity?

A I'm employed by Dominion Energy, and I serve as the Manager of Electric Distribution DG Integration for our North Carolina and Virginia service territories.

Q Did you cause to be prefiled in this docket on November 19th, 2018 28 pages of direct testimony in question and answer form and Appendix A and one exhibit?

A Yes.

Q Do you have any changes or corrections to that direct testimony?

A No.

Q If I were to ask you the same questions that appear in your direct testimony today, would your answers be the same?

A Yes.

Q Did you also cause to be prefiled in this docket on January 8th, 2019 26 pages of rebuttal testimony in question and answer form?

A Yes.

Q Do you have any changes or corrections to that rebuttal testimony?

A No.

Q And if I were to ask you the same questions that appear in your rebuttal testimony today, would your answers be the same?

A Yes.

MS. KELLS: Mr. Chairman, at this time I would move that the prefiled direct and rebuttal testimonies and Appendix A of Mr. Nester be copied into the record as if given orally from the stand, and that his one direct exhibit be marked for identification as prefiled.

CHAIRMAN FINLEY: Now, Mr. Nester's direct prefiled testimony of 28 pages of November 19, 2018 and his one exhibit are copied into the record as though given orally from the stand, and his one direct exhibit is marked for identification as premarked in the filing.

(Whereupon, the prefiled direct testimony and Appendix A of Michael J. Nester was copied into the record as if given orally from the stand.)

(Whereupon, DENC Exhibit MJN-1 was identified as premarked.)

# DIRECT TESTIMONY OF MICHAEL J. NESTER ON BEHALF OF DOMINION ENERGY NORTH CAROLINA BEFORE THE NORTH CAROLINA UTILITIES COMMISSION DOCKET NO. E-100, SUB 101

**Q. Please state your name, business address, and position with Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company").**

A. My name is Michael J. Nester. My business address is 200 Vepco Street, Roanoke Rapids, North Carolina 27870. My title is Manager – Electric Distribution Distributed Generation Integration. A statement of my background and qualifications is attached as Appendix A.

**Q. Please describe your area of responsibility with the Company.**

A. I am responsible for leading the team that administers the process by which Interconnection Customers[1] request and are issued approval to operate generation in parallel with the distribution grid, excluding net metering requests. This process includes the receipt of requests, the facilitation of technical studies to identify grid modifications and protection requirements to accommodate the request, development of study reports to reflect study findings, the development and execution of interconnection agreements and receipt of payments, and administration of the construction of the specified

[1] Terms not otherwise defined in my direct testimony are defined in the NC Interconnection Procedures.

grid modifications and protection requirements, as applicable, to accommodate the proposed interconnection.

**Q. What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to support the proposed revisions to the North Carolina Interconnection Procedures ("NCIP" or "NC Procedures") made by the Company jointly with Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together, the "Duke Utilities" and, jointly with DENC, the "Utilities"). My testimony explains the reasoning behind certain of the Utilities' proposed modifications to the NCIP, and presents the Company's position in response to certain modifications proposed by intervenor stakeholders in this proceeding that were not reflected in the Utilities' proposals.

**Q. In the course of your testimony will you introduce an exhibit?**

A. Yes. I am sponsoring DENC Exhibit MJN-1, which is the Joint Utilities Redline included as Attachment 1 to the Joint Reply Comments filed by the Utilities in this docket on March 12, 2018.

**Q. Would you please describe the current status of the Company's interconnection queue?**

A. Yes. Since 2011, DENC has made operational 72 non-net metering state jurisdictional solar generation projects in its North Carolina service area with a total capacity of approximately 473 MW as of October 2018. DENC has also connected 10 Federal Energy Regulatory Commission ("FERC") jurisdictional solar generation projects in North Carolina since 2011 totaling 370 MW, bringing the total combined capacity of state- and FERC-jurisdictional projects in DENC's North Carolina service area to 843 MW. As of October 2018, the Company has 22 North Carolina jurisdictional Interconnection Requests representing a total of approximately 113 MW of solar generation for which Interconnection Customers have executed Interconnection Agreements to authorize construction of grid modifications needed to accommodate the proposed interconnections. The Company also has 29 North Carolina jurisdictional Interconnection Requests totaling approximately 147 MW of solar generation in an active study status. Collectively, DENC has received over 220 North Carolina state jurisdictional Interconnection Requests, excluding net metering, totaling approximately 1259 MW since 2011. As demonstrated by this data, the Company has processed and connected a significant volume of Interconnection Requests under the NC Procedures, especially as compared to its relatively limited North Carolina service area, for which the average on-peak load during 2017 was 520 MW.

**Q. Have you observed an improvement in the progression of Interconnection Requests through the Company's queue since 2015?**

A. Yes. The May 2015 revisions to the NC Procedures, which were approved by the Commission with support from the Utilities and the Public Staff along with a significant number of solar developers and other stakeholders, were intended to promote efficiency and address the backlog in the North Carolina interconnection study queue. For example, queue management initiatives described in Section 1.1.3 of the NCIP were designed to initially filter the queue of Interconnection Requests that were more speculative in nature. For the remaining Interconnection Requests, as well as for new Interconnection Requests received, the May 2015 Procedures contained provisions intended to encourage Interconnection Customers to submit the most viable Interconnection Requests, and to promote efficiencies in the interconnection study process. Key provisions added that targeted these areas were an increased deposit requirement for the Section 4 Full Study Interconnection Request, clarification of Material Modifications for which a new Interconnection Request may be required, interdependency criteria to assist with the order in which the Utilities study Interconnection Requests, and clarification of process steps by which Interconnection Customers make business decisions in order to keep the interconnection study process moving forward. These revisions did help clear the Company's North Carolina interconnection study queue. In addition, DENC has added incremental staffing and re-evaluated internal processes since May 2015 to administer, study, and manage construction of Interconnection Requests in a more effective manner.

**Q. Did the Company actively participate in the 2017 Stakeholder Process?**

A. Yes. Pursuant to the Commission's directive in the May 15, 2015 *Order Approving Revised Interconnection Standard* (the "2015 Order"), the Public Staff initiated this stakeholder group in early 2017. The Company actively participated with the Public Staff, the Duke Utilities, renewable energy developers, and numerous other stakeholders in a number of general stakeholder meetings and conference calls over the course of several months. At those meetings, DENC shared the Company's experiences with interconnection under the current NCIP. The Company negotiated in good faith with other stakeholders and adopted process improvements to the NCIP in response to stakeholder feedback. Although the Company was able to come to agreement with the Duke Utilities concerning revisions to the NCIP, a consensus was not reached between the Utilities and other stakeholders. Because there was no consensus, the Utilities submitted their Joint Initial Comments, an Attachment 1 detailing their review and responses to over 60 stakeholder comments, and a "Joint Utilities Redline" detailing their specific provisions to the current NCIP, on January 29 and 30, 2018. On March 12, 2018, in response to comments submitted by the North Carolina Sustainable Energy Association ("NCSEA"), Interstate Renewable Energy Council ("IREC"), and the North Carolina Pork Council ("Pork Council"), the Company together with the Duke Utilities submitted Joint Reply Comments and an amended Joint Utilities Redline.

**Q. What is the Company's overall position with respect to the effectiveness of the currently approved NCIP and the need for changes?**

A. Since the 2015 NCIP revisions took effect, North Carolina has become a nationwide leader in the number of installed utility-scale solar generation projects. According to the Energy Information Administration, North Carolina is second only to California in terms of total utility-scale solar MW installed as well as second in total utility-scale solar MW installed during the three year period (2015-17) subsequent to the May 2015 revisions to the NC Procedures. This development has been made possible at least in part by the progress in advancing the North Carolina interconnection study queue that has resulted from the Utilities' implementation of the NCIP as revised in 2015. In general, and based on this progress, the Company does not believe that the NCIP presents any significant structural issues, and therefore does not believe significant modifications are necessary to better serve the Utilities or Interconnection Customers. The Company does, however, believe that certain limited adjustments to the NCIP will facilitate future processing of Interconnection Requests. I provide further detail on the Company's position on these issues below.

<u>Fast Track and Supplemental Review</u>

Q. **Based on the Company's evaluation of the currently effective Fast Track and Supplemental Review Process, are major adjustments needed to these provisions of the NCIP?**

A. No. During the stakeholder process that preceded the 2015 Order, IREC proposed revisions to the Fast Track and Supplemental Review process that were ultimately rejected by the Commission. However, in the 2015 Order, the Commission directed the Utilities to reconsider these issues in the course of the 2017 Stakeholder Process. Consistent with this directive, the Company evaluated the Section 3 Fast Track and the Supplemental Review Processes, and based on that evaluation agreed with the Duke Utilities that only minimal revisions are needed to address minor inefficiencies with these processes.

Q. **What minimal revisions to the current Section 3 Fast Track and Supplemental Review Processes have the Utilities proposed?**

A. As shown in the Joint Utilities Redline, the Utilities have proposed a new Section 3.1.1 that allows each Interconnection Customer the option to select both Fast Track and Supplemental Review on the Interconnection Request Application Form, and pay the applicable Fast Track fee and a Supplemental Review deposit at the time the customer enters the Fast Track process. The intent of this proposed change is to allow an option for increased efficiencies in processing Interconnection Requests by eliminating time delays between the Section 3.3 customer options meeting and receipt of the required

Supplemental Review deposit, and by allowing an Interconnection Customer that fails the Section 3.2.1 Fast Track screen an option by which to more timely proceed to Supplemental Review.

While DENC supports proposed Section 3.1.1, the Company expects that its own Interconnection Request processing will experience limited efficiency gains as a result of this change. As discussed during the stakeholder process, DENC has had limited experience in processing Fast Track Interconnection Requests, but has found that continued evaluation of power-export Interconnection Requests that failed the Fast Track screens has required Full Study, rather than Supplemental Review, as more than minor grid modifications have been required to accommodate these interconnections. The Company supports the option of the streamlined Fast Track/Supplemental Review process, however, based upon Duke Energy's experience.

**Q. Have the Utilities proposed other revisions to Section 3?**

A. Yes. We have proposed minor additional revisions. The Utilities proposed to strike Section 3.2.1.4 due to limited application of synchronous and induction machines pursuing interconnection through the Fast Track process. The Utilities also proposed to reduce the timeframe in Section 3.4 in which the Interconnection Customer must agree in writing to a Supplemental Review from 15 Business Days to 10 Business Days for consistency with Section 3.3.2. Finally, the Utilities proposed to revise Section 3.4.1.2 to clarify the process for circumstances where Interconnection Customer facility modifications are required.

**Q. Did other stakeholders propose revisions to Section 3?**

A. Yes. IREC proposed to increase the size limit for Fast Track eligibility on lines with a voltage of less than 5 kV, regardless of location, to accommodate projects of up to 500 kW. IREC also proposed revisions to the Section 3.2.1.2 15% Fast Track Screen, arguing that the Utilities improperly too narrowly defined "line section."

**Q. What is the Company's position with regard to these proposals?**

A. The Company disagrees with these proposals. With regard to the proposed increased size limit for Fast Track, 5 kV circuits are an older type of distribution infrastructure that require particular care to ensure interconnections are established safely and reliably. Additionally, because only 3 out of the Company's 108 distribution circuits in North Carolina are of this voltage class, IREC's proposal would not significantly improve the Company's Interconnection Request processing. With regard to the proposed revisions to the Fast Track Screen, changing the definition of the screening zones to allow more projects to avoid triggering the Section 3.2.1.2 screen, which ensures safe and reliable interconnection, would risk the loss of visibility to technical issues closer to the customer's premises. Additionally, while DENC believes "line section" to be sufficiently defined in the screening criteria in Section 3.2.1.2, the Company does not oppose adding this definition to the Glossary of Terms, if beneficial for clarification purposes.

Q. **Did other stakeholders propose revisions to the Supplemental Review process specifically?**

A. Yes. IREC proposed to "supplement" the 90% of substation and circuit minimum load Fast Track screen provided at Section 3.2.1.3 with a more comprehensive 100% of minimum load screen. IREC also proposed that voltage and power quality and safety reliability screens be formally added to the Supplemental Review Process.

Q. **What is the Company's position with regard to these proposals?**

A. The Company disagrees with IREC's proposed changes. In general, the Company's position is that the current Supplemental Review process is working efficiently, and that no major modifications should be made at this time.

Regarding the proposed 100% of minimum load screen, as discussed in the Joint Reply Comments and explained further below, this would be technically inappropriate. Downstream zones will typically not be equipped with metering. Distribution planning models and their corresponding load allocation algorithms have historically tended to focus on peak levels rather than minimum load levels, making estimation of minimum load levels inherently less accurate for downstream zones. Additionally, applying a 100% of minimum load screen would imply that minimum load levels will not decrease. Load patterns inevitably shift around on distribution circuits, making a minimum load screen at that level not appropriate for a Fast Track screen.

Regarding the power quality and safety reliability screens, notably the Commission rejected the same proposal by IREC in the 2015 Order, based on the analysis that applying additional screens to an already clogged queue would only exacerbate the problem. This is still true today. Moreover, accepting IREC's proposal would ultimately formalize screens already established by the System Impact Study screens, thereby resulting in: (1) a decrease in the Utilities' flexibility to more efficiently manage Interconnection Requests; and (2) the imposition of additional administrative burdens on the Utilities, causing a diversion of resources better spent on clearing the queue.

**Q. Please elaborate on the reasons for the Company's position that the current Fast Track and Supplemental Review process is working efficiently.**

A. The Company has had limited experience in processing Fast Track Interconnection Requests. From January 2015 through September 2018, the Company received 23 power-export, distribution-connected Fast Track eligible requests. All of these requests that requested Fast Track processing failed the applicable screens but were afforded the opportunity to consider further evaluation under the Full Study process. In this same time period, the

Company received 3 Net Metering requests that were successfully processed through Fast Track and/or Supplemental Review. The Fast Track processes should be designed to minimize risk to the Utility's grid such that additional study is not required. The current Fast Track process appears to meet this goal based on our limited experience. The Company's position therefore is that only minimum modifications should be made to these study processes at this time.

**<u>Timeframes</u>**

**Q. Did the Utilities propose to revise any of the timeframes contained in the NCIP?**

A. Yes. The Utilities proposed to extend the deadline provided by Section 4.2 for holding a scoping meeting from ten (10) to thirty (30) Business Days after the Interconnection Requests are deemed complete or as otherwise mutually agreed to between the Utility and the Interconnection Customer. This extension is intended to give Interconnection Customers enhanced scoping information concerning their proposed generating facility by allowing the Utilities additional time to collect, study, analyze, and report the data.

The Utilities also proposed to revise the required timeframe under Section 5.2.4 for payment and financial security of an Interconnection Agreement from 60 calendar days to 45 Business Days after delivery of the Interconnection Agreement for signature. While this revision may result in extending the timeframe for payment depending upon the applicable month and holiday schedule, the average duration provided for payment under the proposed 45 Business Days is effectively the same as the 60 calendar days currently contained in the NC Procedures. This change will better align this provision with the use of Business Days in other sections of the NCIP.

**Q. What is the Company's position with respect to IREC's proposals concerning deadlines?**

A. IREC makes several proposals relating to the Utilities' meeting timelines provided in the NCIP. These proposals would (1) require the Utilities to report to the Commission on missed deadlines, (2) require a refund deposit "penalty" for missed deadlines, and (3) require the payment of interest on those refunds if they are not made within specified timeframes. Similarly, as indicated in the redlined NC Procedures filed in this proceeding on December 15, 2017, Strata Solar suggested adding language to Section 6.6.3 of the NCIP that would require the payment of interest upon a utility's failure to provide refunds to Interconnection Customers by a specified deadline.

As an initial matter, DENC has and continues to make good faith efforts to meet the "reasonable efforts" requirements contained in NCIP Section 6.1 and to adhere to timelines in a reasonable manner. The Company does not believe that it would be appropriate to adopt IREC's or Strata Solar's proposals given DENC's continued efforts in this regard.

With regard specifically to the proposed imposition of interest on refunds, IREC and NCSEA made similar proposals in the 2015 stakeholder process, and the same reasons why such proposals were inappropriate at that time continue to be true today. For example, interconnection deposits are intended to fund the Utilities' actual costs incurred in processing Interconnection Requests and are therefore not comparable to retail service security deposits that do accrue interest. The Utilities are not holding the full amount of the Interconnection Customer's deposit throughout the Interconnection Request relationship, but are doing the work that the deposit was designed to pay for and effectively drawing down on the deposit amount.

In addition, IREC's proposals would effectively impose a higher standard on the Utilities than reasonable efforts, since for example even with reasonable efforts a timeline may not be met. Moreover, again, imposing additional reporting burdens on the Utilities will only divert resources from processing Interconnection Requests and make the process less, not more, efficient. Finally, the long-established complaint and dispute resolution process provided in the current NC Procedures already provides Interconnection Customers relief from any utility's failure to make reasonable efforts to adhere to the NCIP's timeframes. Based on all of these factors, the Company believes that the Commission should reject these proposals as it did in the 2015 Order.

## Queue Management and Reporting

**Q. Please provide an overview of the reporting requirements established throughout the 2015 stakeholder process.**

A. During the 2015 stakeholder process, several stakeholders raised the issue of the need for increased transparency related to queue performance and queue status. In response to these concerns, the Utilities committed to develop quarterly queue status and queue performance reports in order to better facilitate developers' project planning. In the 2015 Order, the Commission agreed that the Utilities should increase transparency in the interconnection process and directed the Utilities to file the quarterly queue performance and queue status reports going forward.

**Q. Has the Company complied with the current reporting requirements?**

A. Yes. Since 2015, the Company has complied with the reporting requirements, submitting quarterly reports in Docket No. E-100, Sub 101A. The Company's current reports provide the Commission and Interconnection Customers with a "big picture" of the total number of Interconnection Requests and projects under study.

**Q. Is the Company proposing to revise these requirements at this time?**

A. No. The Company believes the current requirements strike a reasonable balance between providing information to developers and not overly burdening the Utilities.

**Q. Did other stakeholders propose revisions to the NCIP reporting requirements?**

A. Yes. In its initial and reply comments, IREC proposed that the Utilities be required to make their interconnection queues publically available on their web sites, update those public queues monthly, and include more granular detail regarding the status of individual Interconnection Requests. IREC also suggested that the Commission require the Utilities to develop hosting capacity maps, and supported the proposal of Strata Solar made during the stakeholder process that the Utilities be required to develop and maintain an online portal through which Interconnection Customers would track their projects. NCSEA supported IREC's suggestions and likewise advocated for greater reporting requirements, including for the Utilities to make data and information that is provided to Interconnection Customers available publically.

**Q. What is the Company's position on the proposal for more granular reporting requirements using web-based or other technologies?**

A. As I explained above, the Company is complying, and commits to continue to comply, with the current reporting obligations. However, the Company processes its queue and develops quarterly queue status and performance reports manually, using spreadsheets to track interconnection requests and pulling information from the spreadsheets to prepare the quarterly reports. While it is investigating the potential for implementing web-based or other queue administration platforms, DENC is not yet in a position to commit to such technology. More granular reporting would simply increase the potential to negatively impact the processing of interconnection requests as resources are utilized for reporting, which is already a time-consuming process, rather than processing. Even if the Company had web-based or other technologies in place, IREC and NCSEA's proposals do not consider the additional costs and administrative burdens associated with their proposals, including costs and burdens relating to development and maintenance of such platforms, or to addressing data security issues that would arise with the use of such technologies. Therefore, DENC does not recommend that web-based or other technologies for more granular reporting be part of the regulations as a requirement.

Additionally, Interconnection Customers have the opportunity to directly contact DENC to inquire about their project status between Queue Performance Report filings, and many Interconnection Customers utilize this opportunity. DENC will generally discuss the interdependency status of the application, as well as the current study status of the request. If available, DENC will also share highlights of grid modifications that the study process has identified thus far, particularly if the grid modification identified appears to be significant. Therefore, based on its own experience, the Company supports the current NC Procedures' reporting requirements as reasonable and sufficient to efficiently manage the queues. DENC continues to be willing to meet with stakeholders, however, to discuss how the existing reports are being utilized.

**Q. Does the Company support IREC's proposed "Hosting Capacity Maps?"**

A. No. The Company does not believe that it would reasonable or appropriate to include in the NCIP a requirement to develop hosting maps at this time.

First, the NCIP already provides methods by which an Interconnection Customer can obtain site-specific pre-application information regarding electrical infrastructure and queue information, through the Section 1.2 Pre-Request Response and the Section 1.3 Pre-application Report. These methods for obtaining pre-application information are more site-specific than can reasonably be provided via a hosting capacity map.

In addition, the Company is concerned that IREC's proposal does not provide clarity as to the timeframe for development of such maps, or the cost responsibility for that development. Nor have any details been provided with regard to how such maps could be designed in a manner that would protect confidentiality and sensitivity of utility grid infrastructure information, or to the frequency of updates that would needed to ensure that map information remains relevant and applicable.

DENC is not opposed to investigating potential development of a Hosting Capacity Map tool for future application. For clarity, hosting capacity is the amount of distributed energy resources ("DER") that a feeder can accept before incurring negative impacts that require additional

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investments. The Company recognizes the potential value of a broader system-wide hosting capacity analysis including platforms and presentment systems that can be regularly updated to reflect growing DER penetration, and is currently assessing the feasibility of pursuing a system-level hosting capacity analysis including platforms and presentment systems that can be regularly updated to reflect growing DER penetration. However, the Company does not support including a hosting capacity map requirement in the NCIP for the reasons I have discussed.

Q. **Does the Company support NCSEA's proposal to make Pre-application Reports public?**

A. No. The Pre-application Report is not designed for public consumption. The Pre-application Report is request specific and electrical infrastructure specific, and is based on readily available information at the time of the request that is subject to change. In addition, the information contained in the Pre-application Report could be considered business confidential by the requesting party and DENC, and the Company should not be required to negotiate confidentiality agreements as an additional administrative burden as part of this process.

## Dispute Resolution

**Q. Please describe the dispute resolution process provided by the current NCIP.**

A. Currently, NCIP Section 6.2 provides a dispute resolution process for Interconnection Customers with a complaint against an interconnecting utility. Section 6.2 specifically allows an Interconnection Customer to submit an informal Notice of Dispute to the utility, and allows for the Public Staff's assistance in informally resolving the dispute if it is not resolved within ten (10) days following a Notice of Dispute. Section 6.2 further provides that an Interconnection Customer may file a formal complaint with the Commission if the parties, with the assistance of the Public Staff, are unable to informally resolve the dispute.

**Q. In your opinion, is this existing dispute resolution process sufficient?**

A. Yes. The Company has successfully resolved disputes under the current Section 6.2 and sees nothing to indicate that it cannot continue to use this provision to successfully resolve any future disputes that arise. IREC has proposed to introduce an interconnection ombudsperson or a third-party mediator in place of the Public Staff for mediation should interconnection parties fail to reach dispute resolution, but offers little evidence supporting a change to the currently effective process. Additionally, the introduction of an ombudsperson appears inconsistent with treatment of disputes for retail customers. Moreover, while IREC compares its proposal to the processes used in California and Massachusetts, I do not believe that other states' interconnection processes are best suited to meet the interconnection challenges that arise in this State with its own unique interconnection landscape.

**Q. Would it be appropriate for a third party to determine what constitutes Good Utility Practice for the Company?**

A. No. DENC should determine what constitutes Good Utility Practice for its service territory within the parameters of the definition of this term contained in the NCIP. The utility is responsible for the operation of the grid under N.C. Gen. Stat. § 62-2 and should therefore retain the primary role for determining Good Utility Practice.

Moreover, the Utility is the most consistent party associated with the interconnection process since, in the Company's experience, many developers of interconnection projects that desire to participate in the determination of Good Utility Practice have no intent to operate their generating facilities for any significant length of time but, rather, intend to sell their generating facilities as the business proposal for which the project was developed. This observation is evidenced by the many change of control requests that the Company has received and processed since the 2015 NC Procedures were approved.

**Interconnection Requirements and Studies**

Q. **Does the Company support NCSEA's and IREC's proposal to form a Technical Working Group for the development and revision of the NCIP?**

A. No. As I have explained, each utility develops practices and standards that constitute Good Utility Practices as defined in the NCIP. The study process is designed to identify grid modifications needed to accommodate an Interconnection Request. While some limited utility-specific interconnection study criteria may be applicable for posting to the Company's website, the premise of performing a study and providing utility flexibility to refine study criteria should be maintained. The utility, not the Interconnection Customer, is responsible for the operation of the grid under regulation and therefore, needs to retain the primary rôle for determining interconnection requirements. A Technical Working Group involving stakeholders may be beneficial for communication of general parameters, but this group should be at the option of the utility, or upon request of developers, not as part of regulation. Specific interconnection information is already communicated to individual developers regarding their Interconnection Requests that cannot be shared in a group setting due to confidentiality.

Q. **Does the Company support Strata Solar, NCSEA, and IREC's proposal to add language to the NC Procedures requiring the Utilities to provide all underlying analysis used to reach the conclusions set forth in the System Impact Study?**

A. No. The proposed language is not necessary, since under the current NCIP DENC provides follow up information to Interconnection Customers upon request, and will continue to provide information, as reasonable, to address an Interconnection Customer's questions about the study reports, with the caveat that some model-specific information, for example, may be proprietary.

**<u>Best Efforts</u>**

Q. **Does the Company support NCSEA's proposal to replace "reasonable efforts" with "best efforts" in Section 6.1?**

A. No. Reasonable efforts is a more appropriate terminology. As the Commission determined in the 2015 Order in rejecting a similar proposal by NCSEA in that proceeding, "best efforts" is unclear as to interpretation and determination, while "reasonable efforts" is a common legal term understood by the parties and the NCUC.

Standby Generators

**Q. Did the Utilities propose any revisions to the NC Procedures to address what are called standby generators?**

A. Yes. The proposed new Section 1.8.3.4 is intended to support and clarify the processing of non-power export Interconnection Requests, otherwise known as "standby generators," that are installed by retail customers. The proposed language provides that, in the case of a standby generator, "...the Utility shall designate the Standby Generation Facility for expedited Section 4 study as a Project A and also ahead of all other Section 4 studies currently underway in the Utility Study queue, unless there are other Standby Generation Facilities currently under study, in which case such Standby Generation Facilities shall be studied in their own queue order."

**Q. Does this proposal not allow standby generators to "jump the queue"?**

A. Unlike generators making sales to utilities under PURPA, which are "sell all" power export generators, standby generators are "back-up" generators that support existing and/or future retail customer operations. Thus, to qualify for Section 1.8.3.4, a proposed generator installation must show that it is not-for-power exports, and, therefore, does not impact the infrastructure capacity of the distribution grid up-line from the Point of Interconnection, as most other generating facilities do. Because standby generators are zero export generation and are not interdependent, they have no adverse effect on other facilities' queue position. Therefore, the language proposed by the Utilities is meant to clarify the process by which standby generator requests are addressed and expeditiously move these facilities through the interconnection process from a customer service perspective, not "jump" standby generators "ahead" of other projects.

**New Technologies**

**Q. Did the 2017 Stakeholder Process discussions address new technologies?**

A. Yes. Throughout the 2017 Stakeholder Process, the Company, together with the Duke Utilities and other stakeholders, actively discussed new technologies, such as renewable plus storage components and smart inverters, and whether or how such new technologies needed to be addressed by revisions to the current NCIP. The result of these discussions is proposed new language regarding energy storage facilities. Additionally, in response to stakeholder concerns, the Company removed its initial suggestion to limit interconnection to only those facilities that were certified.

However, the Company opposes SMA's and QF Solutions' proposal to revise the System Impact Study Agreement to indicate that the Company consider voltage control functions of inverters prior to determining the requirements for utility upgrades. Although DENC acknowledges the potential for inverter-based generating facilities to provide grid support through the use of smart inverter functionalities, we do not depend on those functions for normal day-to-day operation of the electric power system for reliability purposes. Accordingly, distribution upgrades shall initially be established to mitigate any voltage and other reliability and safety related issues before an Interconnection Customer is requested to provide grid support functionalities. DENC will, however, consider the use of these functionalities for future operational issues after our mitigation tools have been utilized with respect to safety and reliability under Good Utility Practice.

On a broader note, while the industry continues to work towards the application of these technologies to support the distribution grid, the reality is that we are not there yet in terms of broad deployments. Only in the most recent revision of the IEEE 1547 standard, released earlier this year, are smart inverters required to be *capable* of supporting the grid for specific functionality. The Energy Policy Act of 2005 established IEEE 1547 as the national standard for the interconnection of distributed generation resources in the U.S. The Company is an active participant in the IEEE 1547 revision with a Company engineer recently moving into a leadership role on the technical working group. Proven industry standard equipment and systems remain the primary means to manage grid voltage and power flows as the system evolves. The Company is responsible for delivering safe and reliable energy to customers and a prudent approach to the application of new technologies is critical in doing so. As the industry continues to evolve in terms of using smart inverter functionality for grid support, close interaction, and communication, between the Company and DER customers will be critical to ensuring success as this approach matures to Good Utility Practice status.

**Q. Please describe the Utilities' proposed new language on Maximum Generating Capacity.**

A. As shown in the Joint Utilities Redline, the Utilities are proposing to revise Section 6.10.2 to specifically allow a more limited generating capacity to be studied if the applicant can show that appropriate controls are in place subject to mutual agreement.

## Proposed Fee Increases

**Q. What is the Company's position on specified fee increases proposed by the Utilities?**

A. The proposed fee increases reflected in Figure 6 beginning on Page 38 of the March 12, 2018 Joint Reply Comments are based upon supporting justification provided by the Duke Utilities. In the December 15, 2017 Redline of Working Group Recommendations, DENC had proposed an increase in the 100 kW to 2 MW Fast Track request fee from $500 to $1000 on the basis that these requests require a fairly significant review time by engineering staff to review screens and explain results to the Interconnection Customer. The justification for fee increases provided by Duke Energy is more comprehensive and quantifiable. DENC supports the justification provided by Duke Energy and the proposed increases.

## Summary

**Q. Do you have any summary comments regarding changes to the NCIP?**

A. Yes. DENC has made significant progress in the administration of its interconnection study queue since the May 2015 revisions to the NC Procedures. Those revisions, together with the Company's incremental staffing and process implementation, have effectively resulted in the elimination of the study queue backlog that DENC discussed during the 2014-2015 stakeholder process. This progress is evidenced by the quarterly Queue Status and Performance Reports that the Company has filed with the Commission since September 2015, as well as by the magnitude of Interconnection Requests and MW of solar generation that the Company has connected in our service territory since 2015. The Company has achieved this progress with relatively limited experience under the current NCIP, which has only been in effect since May 2015. Based on all of these considerations, DENC recommends targeted revisions to the North Carolina Interconnection Procedures as reflected in the Joint Utilities Redline, rather than wholesale or comprehensive changes to a standard that has been in effect for a limited amount of time.

**Q. Does this conclude your testimony?**

A. Yes, it does.

APPENDIX A

## BACKGROUND AND QUALIFICATIONS OF MICHAEL J. NESTER

Michael J. Nester received a Bachelor of Science degree in Electrical Engineering from North Carolina State University in 1986 and is currently the Company's Manager of Electric Distribution Distributed Generation Integration. He started his career with the Company in 1986 as an Associate Engineer in the Southern Division Planning and Engineering Department in Roanoke Rapids, North Carolina. Since joining the Company, Mr. Nester has held positions in multiple areas of the Company including Planning and Engineering, Marketing, Energy Efficiency, Evantage (a former energy services company of Dominion Energy), Key Accounts, Wholesale Customer Relationship Management, and Electric Wholesale Interconnection. Mr. Nester is a registered Professional Engineer in the State of North Carolina. He is a member of the Association of Energy Engineers and is a Certified Energy Manager, Certified Energy Procurement Professional, and a Certified Green Building Engineer.

CHAIRMAN FINLEY: Mr. Nester's rebuttal testimony of 26 pages of January 8, 2019 is copied into the record as though given orally from the stand.

(Whereupon, the prefiled rebuttal testimony of Michael J. Nester was copied into the record as if given orally from the stand.)

**REBUTTAL TESTIMONY
OF
MICHAEL J. NESTER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 101**

**Q. Please state your name, business address, and position with Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company").**

A. My name is Michael J. Nester. My business address is 200 Vepco Street, Roanoke Rapids, North Carolina 27870. My title is Manager – Electric Distribution Distributed Generation Integration.

**Q. Are you the same Michael J. Nester who prefiled direct testimony on behalf of the Company in this proceeding on November 19, 2018?**

A. Yes, I am.

**Q. What is the purpose of your rebuttal testimony in this proceeding?**

A. The purpose of my rebuttal testimony is to respond to the direct testimony offered by the Public Staff – North Carolina Utilities Commission ("Public Staff"), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together, the "Duke Utilities,") the North Carolina Sustainable Energy Association ("NCSEA"), and the Interstate Renewable Energy Council ("IREC") in this proceeding and to provide further support for the proposed revisions to the North Carolina Interconnection

Procedures ("NCIP" or "NC Procedures") made by the Company jointly with the Duke Utilities (jointly with DENC, the "Utilities").

## INTRODUCTION

**Q. What is your overall response to the direct testimony offered by the other parties to this proceeding?**

A. The Company continues to support the positions articulated in the Joint Initial Comments, and the accompanying Joint Utilities Redline of the NC Procedures, filed by the Utilities on March 12, 2018. Consistent with the Joint Initial Comments, the Company believes that it is prudent and appropriate at this juncture to make minor modifications to the NCIP, but that major modifications are not needed at this time. In response to the direct testimony, the Company does not support proposals for additional reporting frequency and obligations, as these requirements would only place additional administrative burden on DENC that would take resources away from, rather than facilitate, the processing of Interconnection Requests.[1]

Additionally, while several intervenors propose changes that would effectively socialize the determination of Good Utility Practice, DENC believes that the determination of Good Utility Practice is a critical area in which the utility needs to remain predominantly responsible.

[1] Terms not otherwise defined in my rebuttal testimony are defined in the NC Procedures.

In summary, the Company believes that the interconnection process is designed to ensure the safety, reliability, and operability of the grid for all customers, and the Company's positions that have been articulated in both the stakeholder working groups and through my direct and now my rebuttal testimonies are intended to achieve that objective.

## ONLY MINOR MODIFICATIONS TO THE NCIP ARE APPROPRIATE AT THIS TIME

Q. **What is the Company's overall position on the need for revisions to the NC Procedures?**

A. In the three years since the approval of the current NC Procedures in 2015, North Carolina has become second in the U.S. in installed utility scale solar generation. With regard to DENC specifically, the 126 MW of large scale solar that was interconnected to the Company's distribution grid in its North Carolina service area in August 2015 has grown to 568 MW as of November 1, 2018. Based on the experience gained in interconnecting solar generation during this time period, the Company believes that it is prudent and appropriate at this juncture to make minor modifications to the NCIP, as reflected in the March 12, 2018 Joint Utility Redline, rather than a major overhaul. I provide additional support for the minor modifications that the Company believes would be appropriate in this section of my rebuttal testimony, and explain why DENC believes other modifications that have been proposed are not needed or appropriate.

**1. Timeframes**

**Q. Do you support the recommendations made by NCSEA and echoed by IREC regarding the timeline for studying Interconnection Requests?**

A. No. NCSEA made several timeframe proposals in its March 12, 2018 reply comments, a number of which were adopted by IREC witness Auck. As I discuss further below, these recommendations are either redundant or conflict with other provisions of the NCIP.

- NCSEA's proposal for the addition of a 10 Business Day requirement to Section 1.3.3 for the Utilities to provide a Pre-application report is not necessary, as a 10 Business Day requirement is already contained in Section 1.3.1.
- NCSEA's proposed addition to Section 2.2.2 of a 10 Business Day requirement in which the Utilities must provide the reasons for failing the Fast Track screens, which IREC supports, appears to conflict with the 15 business day requirement in Section 2.2.1.
- NCSEA's proposed addition in Section 6.3.3 of a 10 Business Day requirement in which Utilities invoice Interconnection Customers upon issuance of a final accounting report would be inconsistent with the final accounting procedure contained in Section 6.1.2 of the Interconnection Agreement ("IA").
- With regard to NCSEA's and IREC's proposal to reduce the 30 calendar day requirement for refunds under Section 6.3.3 to 10 Business Days, the Company's billing systems are designed to

process refunds consistent with calendar month period, as reflected in the current provision.

- The Company opposes NCSEA's proposed addition to Section 2.3.1 of Attachment 6 of the NCIP of a 10 Business Day deadline to provide a written statement regarding the results of a commissioning inspection, which IREC adopted. This modification is not necessary as Section 2.3.1 already provides that notification of inspection results will take place as soon as practicable after the inspection.

**Q. Please respond to the Public Staff's proposals regarding timelines.**

A. Public Staff witness Lucas recommended adoption of most of NCSEA's proposals, which I address above. With regard to the Public Staff's proposal of a 60 Business Day target for final accounting in Section 6.3.3, the Utilities proposed 90 Business Days to allow more time for study expense reconciliation, particularly if contractors are utilized for study. The Public Staff proposal of 60 Business Days is generally equivalent to the existing 90 calendar day language in Section 6.3.3. With regard to the Public Staff's recommendation to maintain the 10 Business Days provided in Section 4.2.1 to schedule a scoping meeting, the Utilities proposed a 30 Business Day timeframe to allow additional time to collect, study, analyze, and report the data for each project and as a result, better achieve the purpose of the Scoping Meeting as described in Section 4.2.2.

Q. **Does the Company continue to support the other timeline changes that were proposed in the Joint Utilities Redline?**

A. Yes. In the Joint Utilities Redline, DENC modified its original proposal, to revise Section 5.2 to allow for 30 Business Days both to execute a final IA and for the Interconnection Customer to make payment, to support the current time frame of 10 Business Days for signing an IA and the Utilities' proposed 45 Business Days for payment of estimated charges in the IA. These timeframes align both action items to a Business Day structure while retaining a similar time duration to that currently contained in the NCIP.

Q. **What is the Company's position on the additional timeline modifications proposed by the Duke Utilities in their direct testimony?**

A. While DENC has not to my knowledge encountered any issues related to Section 1.8.3.2 of the NCIP, the Company supports the Duke Utilities' proposal to modify this provision, as DENC believes the modification will benefit the interconnection process by clarifying the scoping meeting process for subordinate projects. The Company also agrees with the Duke Utilities' proposal to revise Section 4.2 to clarify that this provision does not apply to an Interconnection Customer that is deemed to be interdependent with more than one other Interconnection Request.

**Q. What is the Company's position on the timeline enforcement mechanism proposed by IREC?**

A. The Company continues to oppose this proposal. The Utilities have made reasonable efforts to administer the timelines contained in the NCIP as evidenced by North Carolina's status as second in the nation in installed solar capacity. Additionally, the current NCIP contains communication and dispute provisions by which timeline issues regarding specified Interconnection Requests can be addressed. The Public Staff also opposes this proposal.

**2. <u>Dispute Resolution</u>**

**Q. What is the Company's position with respect to the proposals to modify Section 6.2 of the NCIP?**

A. The Public Staff recommends a dispute process as shown in witness Lucas's Exhibit 1 that would allow parties to use a third-party mediator. IREC proposes the creation of an interconnection ombudsman to facilitate dispute resolution. The Company does not support these proposals. DENC has successfully resolved disputes under the current Section 6.2 and believes it can continue to use this provision to successfully resolve any future disputes that arise. In addition, introducing an ombudsperson or a third-party mediator in place of or in addition to the Public Staff would be inconsistent with the treatment of disputes for retail customers, who are served by the same grid to which the Interconnection Customers seek interconnection. Finally, and as I discuss further below, it is critical that the dispute resolution process recognize the utility's regulatory responsibility to process Interconnection Requests to pursue the safety, reliability, and operability of the grid for all customers, and to determine Good Utility Practice. The current dispute resolution process reflects that recognition, which would be potentially diluted with the introduction of a third-party mediator or ombudsman.

With respect to the Public Staff's and the Duke Utilities' proposals for additional timeframes for the dispute resolution process, again, the existing dispute process has worked well for the most part in DENC's experience, including with respect to disputes over timelines, and contains timeframe targets for progression of the dispute, if needed. The Company has therefore not seen a need to modify Section 6.2.

### 3. Fast Track/Supplemental Review

**Q. Does the Company continue to oppose the proposals made by IREC with respect to Fast Track and Supplemental Review?**

A. Yes. As I discussed in my direct testimony, consistent with the Commission's directive in the 2015 Order, the Company evaluated the Section 3 Fast Track and Supplemental Review Processes, and based on that evaluation agreed with the Duke Utilities that only minimal revisions are needed to address minor inefficiencies with these processes. Other proposals to revise these processes are either unnecessary or inappropriate, as I explain further below.

Generally with regard to Fast Track, the Company believes that Fast Track screens should be designed to be conservative, with the intention that only those requests that do not impact the grid and do not require additional review will pass the screen, such that no harm to the grid results from no studies being done. It is DENC's position that the existing Fast Track process should be retained, as it appears to be working as designed so that requests that pass the screens do not require additional study

IREC has proposed that all Fast Track eligible projects that fail Fast Track should proceed to the Supplemental Review process with defined screens. DENC opposes this proposal. The Company believes that the Utilities should determine when Supplemental Review is appropriate at the request of the Interconnection Customer.

IREC has also proposed that the size limit for Fast Track eligibility for projects to interconnect to lines with voltage less than 5 kV regardless of location increase to 500 kW. As discussed in my direct testimony, there is limited application of <5 kV operating voltages in DENC's service territory. Significant current injection of 500 kW at <5 kV signals likelihood of screen failures and need for study. Notably, the Public Staff's position is that the 100 kW Fast Track eligibility limit should be maintained for now.

IREC also suggests that further explanation should be added to Section 3.2.1.2 through a "clarifying footnote" to "ensure that utilities apply the screen utilizing a feeder section that includes a larger portion of the entire feeder load."[2] IREC also proposes to revise Section 3.2.1.7, apparently based on the Duke Utilities' practices, to allow the 87.5% limit on protective devices to allow for a higher percentage, which would be a less conservative screen. The Company opposes such modifications to the Fast Track screens that would allow more requests to pass without Supplemental Review or study. Fast Track screens should be conservative and designed such that only requests with no impact to the electric grid will pass without additional review.

IREC also proposes to revise the definition of Line Section in Attachment 1. DENC opposes this proposal. As discussed in my direct testimony, DENC believes Line Section to be sufficiently defined in the screening criteria in Section 3.2.1.2, but does not oppose adding this definition to the Glossary of Terms, if beneficial for clarification purposes. The Public Staff agrees with the Utilities on this issue that the existing Line Section definition is appropriate.

Finally, the Company continues to oppose IREC's proposal to adopt Supplemental Review process with 3 defined screens (1) 100% minimum load, (2) voltage and power quality, and (3) safety and reliability, as discussed fully in my direct testimony.



[2] Direct Testimony of Brian M. Lydic, at p. 12.

**Q. The Duke Utilities have offered proposals through direct testimony to modify certain provisions of the NCIP with regard to Fast Track and Supplemental Review that were not included in the Joint Utilities Redline. What is the Company's position on these proposals?**

A. The Company does not oppose the Duke Utilities' proposal to modify Section 3.1 to allow the utility and Interconnection Customer to mutually agree to Fast Track evaluation for Generating Facilities connecting to lines greater or equal to 35 kV, as long as this revised provision includes the requirement of mutual agreement. With regard to the Duke Utilities' proposal to modify Section 3.2, this proposal appears to allow Fast Track review for both Project As and Project Bs (based on the "is not interdependent with *more than one* Interconnection Request" language). However, based on the Company's understanding of the NCIP, this proposal appears to pose a potential inconsistency with Section 1.8. Finally, the Company does not oppose the Duke Utilities' proposal to modify Section 3.4.1.3 to clarify that a facility study may be required for projects approved in Supplemental Review. While the Company would not oppose the Duke Utilities' proposed changes to Sections 3.1 and 3.4.1.3 if the Commission decides to adopt them, based on DENC's own experience, which has not shown a need for these changes, the Company continues to support the modifications to these NCIP provisions as presented in the Joint Utilities Redline.

**4. Fees/Costs to Grid**

**Q. Do you agree with the Public Staff that interconnection costs should be borne by developers?**

A. Yes. Consistent with Public Staff witness Lucas' testimony, the Company believes that interconnection costs should be borne by developers because the Interconnection Customer is the party causing the costs to be incurred.

In response to IREC's request that the Utilities provide additional explanation for the need for increased fees, DENC had proposed an increase in the 100 kW to 2 MW Fast Track request fee from $500 to $1,000 on the basis that these requests require a fairly significant review time by engineering staff to review screens and explain results to the Interconnection Customer. The justification for fee increases provided by the Duke Utilities, which is reflected in the Joint Utilities Comments and in Duke Utilities witness Riggins' direct testimony and includes an explanation of the proposed reduction in the initial Section 2 fee, is more comprehensive and quantifiable. DENC supports the justification provided by the Duke Utilities and the increases proposed in the Joint Utilities Redline and the Duke Utilities' direct testimony.

**ADDITIONAL REPORTING OBLIGATIONS**

**Q. What is DENC's overall position on the proposals to increase reporting frequency and content?**

A. The Company opposes these proposals. Additional reporting frequency and obligations would increase the Utilities' administrative burden as well as impede the processing of Interconnection Requests. For DENC, such added obligations would impose a significant burden given that the Company administers its queue manually. As I discuss further below, while the Company is willing to evaluate software to assist with queue administration, DENC does not believe that it would be appropriate to require such software as part of the NCIP.

Q. **What is your response to the Public Staff's proposal that the Utilities evaluate the cost of developing and operating an online portal?**

A. The Company does not necessarily oppose the Public Staff's proposal for evaluation of the cost to develop and operate such technology. DENC is currently investigating the potential for implementing software and/or web-based queueing platforms, though we are not yet in a position to commit to such technology. DENC does, however, oppose the inclusion of any requirement regarding web-based/software development in the NCIP at this time, due to the lack of clarity with regard to the timeframe for the development of such software and the cost responsibility for such development.

Q. **Do you support the Public Staff's recommended modifications to the Utilities' annual reports listing interconnected facilities?**

A. The Public Staff recommended that the Utilities file the list of interconnected facilities, which is currently filed annually by March 31, quarterly, and that these reports be modified to utilize the operational status definitions used in the Utilities' online distribution and transmission queue reports. DENC does not support these recommendations. Increasing the frequency of these reports would increase the Company's administrative burden and therefore result in resources being utilized for additional reporting rather than processing of Interconnection Requests. With regard to the proposal to use operational status definitions, while DENC does not post its reports online, they are publicly available via the Commission's website and, as the Company has received limited inquiries regarding its reports since 2015, it does not believe this added requirement should apply to DENC.

The Public Staff also proposed that the list of interconnected facilities be modified to include FERC jurisdictional Interconnection Requests. DENC does not object to this proposal, as long as it is limited to the FERC interconnections that are placed into operation. PJM administers the FERC jurisdictional Interconnection Requests in DENC's service territory. Specified queue information regarding these requests is currently available on PJM's website. At the request of the Public Staff, DENC has been including in its annual and quarterly reports FERC jurisdictional interconnections that have been placed into operation, and plans to continue to include this information in future reports, even though the Commission has not directed the Company to provide this information. However, DENC does not include in its North Carolina reports data on all Interconnection Requests that are submitted to PJM for interconnection with the Company, regardless of their status. Such information, which is extensive, is already available on PJM's website. A requirement to duplicate or recreate this information would impose an unnecessary administrative burden that does not improve the processing of DENC's North Carolina queue. Regarding preliminary interdependency of state projects with FERC projects, DENC's quarterly queue status reports already contain preliminary interdependency status of state projects which incorporates interdependency with FERC projects.

**Q. Please respond to the Public Staff's proposal that the Utilities should be required to file new screens and studies with the Commission for informational purposes, post the information on the utility's website, and present the information for discussion at Technical Standards Review Group ("TSRG") stakeholder meetings.**

A. DENC does not support this proposal. As I discuss further below, Good Utility Practice, which includes the determination and administration of technical practices, must reside with the Utility. The existing NCIP does not define technical methodologies under which Interconnection Requests are studied, but encapsulates these methodologies under Good Utility Practice at the discretion of and with the recognition of the regulatory responsibilities of a public utility. Public Staff witness Williamson acknowledged that Good Utility Practice contemplates an application of lessons learned that is not restricted to a static study process. With regard to concerns about communication of screens and studies, in DENC's experience the communications processes that already exist under the

NCIP allow study parameters to be presented and explained to Interconnection Customers with the opportunity to dispute those parameters should the Interconnection Customer desire. In addition, DENC already communicates specific interconnection information to Interconnection Customers regarding particular requests that cannot be shared in a group setting due to confidentiality, and as the Company does not participate in the TSRG, any requirement to present information at TSRG meetings should not apply to DENC.

**Q. What is your position on IREC's proposals to require the Utilities to provide a detailed public queue, and to require regular reporting on information not available in the public queue, including tracking missed deadlines?**

A. DENC opposes these proposals, which would add to the Company's administrative burden without improving the processing of the queue as resources are utilized for additional reporting rather than processing Interconnection Requests. Existing reporting already illustrates the status and performance of the queue, and as I have noted, DENC has received limited inquiries from Interconnection Customers regarding its quarterly Queue Status and Performance Reports since their inception in 2015. DENC has found that direct communication with Interconnection Customers regarding the status of their specified Interconnection Requests has been the most effective medium by which queue status and performance has been communicated and addressed. With respect to timelines, the existing NCIP has communication and dispute mechanisms by which timelines can be addressed, and the reasonable efforts employed by the Utilities to administer timelines are evidenced by North Carolina's status as having the second most amount of installed solar generation in the nation.

I would also like to respond to IREC's apparent belief that its proposals should not impose a significant burden on the Utilities, since the Utilities should already be tracking the additional information IREC advocates be reported. I disagree with this presumption. The Utilities are required to administer the timeframes contained in the NC Procedures. From the Company's perspective, that does not mean that the Utilities necessarily record when all activities and process steps occur unless such recording is required for reporting purposes. Administration of timeframes can involve other processes, such as placing target dates on Outlook calendars. While the Company is not necessarily recording those dates in its spreadsheet, it pursues the administration of timeframes consistent with the NC Procedures.

**Q. How do you respond to the proposals relating to hosting capacity maps made by the Public Staff and other intervenors?**

A. The Public Staff has recommended that the Duke Utilities provide detailed cost estimates for development and maintenance of hosting capacity maps to the Commission and the Public Staff for review. IREC goes even further and argues that the Utilities should be required to develop hosting capacity maps to direct generators to locations where interconnection will not provoke major upgrades.

DENC is not opposed to investigating the potential development of a hosting capacity map tool for future application. The Company performs locational hosting capacity studies as a component of utility-scale distributed energy resource ("DER") interconnection impact studies and recognizes the potential value of a broader system-wide hosting capacity analysis. DENC is also currently assessing the feasibility of pursuing a system-level hosting capacity analysis including platforms and presentment systems that can be regularly updated to reflect growing DER penetration.

However, the Company opposes including any hosting capacity map requirements in the NCIP. As I stated above, the purpose of the interconnection process is to ensure the safety, reliability, and operability of the grid for all customers. And as I discuss further below, the utility is the proper entity to determine Good Utility Practice. The NCIP should therefore not be modified to incorporate technical requirements or other elements of Good Utility Practice, such that changes to the determination of Good Utility Practice require regulatory modification. In addition, even if developed and utilized, hosting capacity maps will not substitute for the information that is available through Section 1.2 (Pre-Request Response) and Section 1.3 (Pre-Request Application), which already provide Interconnection Customers with site-specific information not readily achievable via a hosting capacity map. Finally, the Company agrees with the Public Staff that the cost of any hosting capacity map development should be recovered from developers, as developers will receive the primary benefit of any such development.

## GOOD UTILITY PRACTICE

**Q. What is DENC's overall position on the proposals that affect the Utilities' determination of good utility practice?**

A. Throughout the stakeholder process and in intervenor testimony, several proposals have arisen – technical working group, ombudsperson in dispute process, "mutually agreeable" language in Section 6.10.2, proposals to file technical requirements with the Commission – that appear to attempt to socialize the determination of Good Utility Practice. DENC believes that the determination of Good Utility Practice is a critical area in which the utility needs to remain predominantly responsible. The utility has the regulatory obligation to operate the grid; other parties petitioning to determine Good Utility Practice by committee do not share that regulatory obligation.

The Company agrees with the Public Staff's testimony that the Utilities are responsible for operating their respective grids, but that to the extent the Utilities identify new or emerging issues, their application of Good Utility Practice must retain some flexibility. DENC takes very seriously its responsibilities and obligations under North Carolina General Statute § 62-2 as a public utility registered to do business in North Carolina. With this responsibility, the primary determination of Good Utility Practice, and the ability to modify Good Utility Practice, must reside with the utility regarding the service territory for which it is responsible. Additionally, the current NC Procedures already provide processes for an Interconnection Customer to obtain additional information regarding the utility's processing and decisions regarding Interconnection Requests. Based on these considerations, the Company does not believe that it would be appropriate to dilute a utility's responsibility to determine Good Utility Practice by transferring Good Utility Practice derivation to Interconnection Customers or third-party mediators who do not share the same regulatory responsibilities of a public utility.

This point is illustrated by the significant number of change of control requests that the Company has received in recent years, which I noted in my direct testimony as showing that many developers do not intend to operate their generating facilities for a significant period of time but rather to sell their projects as a business strategy. Specifically, from 2011 through November 2018, of the 226 Interconnection Requests DENC has received, 64 changed control at least one time, 16 of those 64 changed control at least twice, and 3 of those 16 changed control at least three times.

**Q. What is your position on the recommendations that have been made for independent review of the NCIP and for various stakeholder and working groups?**

A. The Company does not support the Public Staff's recommendation for independent review of the NCIP, as we would anticipate that such review would simply result in an extension of the 2017 stakeholder process, with interested parties reacting to the review's conclusions based on their own perspectives and no additional consensus being reached. DENC does agree, however, with the Public Staff's recommendation to convene an interdependency and cluster study stakeholder group, as we believe that further discussion of these topics, which were not explored by the 2017 stakeholder process, have more potential to improve the processing of full study Interconnection Requests.

The Company opposes IREC's proposal that the Commission convene a state-wide technical working group to continually review the NC Procedures between formal NCIP review proceedings, especially if such a group was intended to be used to determine Good Utility Practice. Each Utility is responsible for Good Utility Practice given the operating characteristics and safety practices specific to its applicable service territory. While the Company sees value in working groups convened by a utility and a specific subset of stakeholders to address particular topics or challenges, we do not believe that a general technical working group such as IREC proposed would be useful or an efficient use of the Utilities' resources.

## OTHER ISSUES

**Q. Does DENC agree with the Public Staff that IEEE 1547 is not a standard that the Utilities are bound to follow but is one that provides guidance on incorporating DER onto the grid?**

A. Yes. DENC believes that the utility should decide when to apply the inverter ride-through and power factor capabilities addressed in IEEE 1547 in accordance with Good Utility Practice. My understanding is that work is still ongoing to revise the IEEE 1547.1 standard (Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources or DERs with Electric Power Systems and Associated Interfaces), which is essential in determining how to test and certify any DER and their smart functions, such as ride-through, in the laboratory and in the field per the DER Interconnection and Performance requirements specified in the new IEEE 1547-2018. The Company anticipates the revision of the IEEE 1547.1 standard to be completed by mid to late 2019 or early 2020.

**Q. Does the Company continue to support its proposed addition in Section 1.8.3.4 for standby generators?**

A. Yes. As discussed in my direct testimony, the proposed new Section 1.8.3.4 is intended to support and clarify the processing of non-power export Interconnection Requests, otherwise known as "standby generators," that are installed by retail customers. The proposed language provides that, in the case of a standby generator, "...the Utility shall designate the Standby Generation Facility for expedited Section 4 study as a Project A and also ahead of all other Section 4 studies currently underway in the Utility Study queue, unless there are other Standby Generation Facilities currently under study, in which case such Standby Generation Facilities shall be studied in their own queue order." Because standby generators are zero export generation and are not interdependent, they have no adverse effect on other facilities' queue position. Therefore, the language proposed by the Utilities is meant to clarify the process by which standby generator requests are addressed and expeditiously move these facilities through the interconnection process from a customer service perspective. The Public Staff supports this proposal.

**Q. What is your response to IREC's concern about the "mutually agreed upon" language in the Utilities' proposed revised Section 6.10.2?**

A. The Utilities proposed to revise Section 6.10.2 to specifically allow a more limited generating capacity to be studied if the applicant can show that appropriate controls are in place subject to mutual agreement. IREC argues that if the use of export-limiting devices is subject to mutual agreement with the utility, and the utility does not agree to software-based controls, facilities will be limited to physical control devices. IREC recommended that the Commission either specify that software controls must be allowed if they can be shown to have been tested using a protocol adequately designed to demonstrate limited export capabilities, or if a Technical Working Group is convened, the Commission should require that group to determine what type of control devices may be allowed.

As I noted in my direct testimony, while the industry continues to work towards the application of smart inverter and other new technologies to support the distribution grid, broad deployment of these developments is not yet feasible. Only in the most recent revision of the IEEE 1547 standard, released in 2018, are smart inverters required to be *capable* of supporting the grid for specific functionality. Proven industry standard equipment and systems remain the primary means to manage grid voltage and power flows as the system evolves. Because the Company is responsible as a public utility for delivering safe and reliable energy to customers, we believe the "mutual agreement" language is needed to confirm that such determinations are made consistent with Good Utility Practice.

Q. **Does the Company agree with IREC's proposal that the Commission clarify a path for rollout of new standards for smart inverters?**

A. No. Technical methodologies should not be specified as part of the NCIP but addressed under Good Utility Practice as provided in the current NCIP, consistent with my explanation above.

**Q. What is your response to IREC on the Company's original proposal to limit interconnection only to certified devices?**

A. DENC withdrew its request in the Joint Initial Comments to require inverter based generation to utilize UL certified inverters. DENC will continue to encourage Interconnection Customers to use UL certified inverters to reduce risks to the electric grid.

**Q. Does the Company continue to support proposed Section 1.8.3.3 as presented in the Joint Utilities Redline?**

A. Yes. This new section allows for expedited consideration and interconnection of small animal waste facilities consistent with North Carolina House Bill 589. The Public Staff also supports this proposal.

**Q. Does DENC support the Duke Utilities' proposal to modify Section 6.5 to establish post-commissioning inspections?**

A. Yes. DENC agrees that it is appropriate to expressly establish a process for post-commissioning inspection of generating facilities.

**Q. The Duke Utilities have also proposed to include additional detail in Interconnection Request forms included in NCIP as Attachment 2 and 6 to allow Interconnection Customers to designate whether the facility is customer owned or leased from an electric generator lessor. Does the Company support this proposal?**

A. Yes. Consistent with an application for retail service that may, pursuant to Section II.A.1 of DENC's Terms and Conditions, be submitted by the owner or bona fide lessee of the premises, the Company believes that it would be appropriate to apply similar criteria to Interconnection Customers.

## SUMMARY

**Q. Please summarize your rebuttal testimony.**

A. Under the current NC Procedures, the Company has successfully addressed its North Carolina study queue backlog, as well as developed more efficient processing of Interconnection Requests and addressing of disputes. Based on this experience, it is my opinion that only minor adjustments to these current NC Procedures are called for at this time, to add efficiencies where appropriate, but that major modifications are not needed and in some cases would likely result in less, rather than more, efficiencies as well as risk the Company's ability to safely and reliably study and connect new Interconnection Customers.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

BY MS. KELLS:

Q Mr. Nester, do you have a summary of your direct and rebuttal testimonies with you?

A Yes, I do.

Q Would you please present that now?

A Certainly. Thank you. Good afternoon. My direct testimony supports the proposed revisions to the North Carolina Interconnection Procedures made by Dominion Energy, Duke Energy Carolinas, and Duke Energy Progress in the joint utility comments filed in this docket on March 12th, 2018. My direct testimony also responds to proposals made by the Public Staff and Intervenors in this case to revise the North Carolina procedures. My rebuttal testimony responds to the direct testimony offered by the Duke Utilities, the Public Staff, NCSEA, and IREC and provides further support for the jointly proposed revisions to the North Carolina procedures made by the Company and Duke.

Since 2011 and as of January 24th, 2019, Dominion Energy has processed and connected 488 MW of non-net metering North Carolina jurisdictional solar generation in its North Carolina service area. Another 98 MW of such projects have executed Interconnection Agreements with the Company, and another 134 MW are in active study status. In my opinion, the revisions to the North Carolina procedures approved by this Commission in May 2015 have met their intended purpose of promoting efficiency and addressing the backlog in the Company's North Carolina interconnection study queue. This progress is demonstrated by this state's position as a nationwide leader in the installation of utility-scale generation and by the quarterly queue status and performance reports Dominion Energy has filed with this Commission.

Based on this progress and my experience, Dominion Energy believes it's prudent and appropriate at this time to make certain limited adjustments to the North Carolina procedures that will facilitate future processing of interconnection requests, but that major changes are not needed at this time. In particular, the Company does not support proposals for additional reporting frequency and obligations since these requirements would put additional administrative burden on Dominion Energy and take resources away from, rather than facilitate, the processing of interconnection requests. In addition, in response to several proposals that would effectively socialize the determination of good utility practice, Dominion Energy believes it is critical that the Utility remain predominantly responsible for good utility practice decisions as it is the Utility that has the regulatory obligation to operate the grid safely and provide reliable and efficient service for customers.

Finally, the Company has agreed to the Stipulation with the Duke Utilities, the Public Staff, and the Pork Council that was filed on January 25th, and I believe the Stipulation to be an acceptable resolution of the issues it addresses.

This concludes my summary. Thank you.

MS. KELLS: The witness is available for cross examination.

CHAIRMAN FINLEY: All right. Let's take our afternoon break and come back at 4:00.

(Recess taken from 3:45 p.m. to 4:00 p.m.)

CHAIRMAN FINLEY: All right. IREC, cross examination.

MS. BEATON: Good afternoon, Mr. Nester, and Mr. Chairman. Laura Beaton for IREC.

CROSS EXAMINATION BY MS. BEATON:

Q And Mr. Nester, if it's uncomfortable for you to turn and look at me, I know I'm right behind your head, feel free to just keep looking ahead.

A Okay.

Q Whatever is more comfortable for you.

A All right. Thank you.

Q Yeah. I just have a few questions for you today. My first question is does Dominion Energy North Carolina currently publish a public interconnection queue like Duke does?

A We do not publish an interconnection queue on our website, but we do have the information publicly available. We have complied with the Commission Order in 2015 to file quarterly reports, and all of our reports since -- I think our first report was September of 2015, and all of those reports are on the Commission website.

Q Okay. Thank you.

A So they are -- they are publicly available.

Q Thank you. Now, I'm going to go through a list of different data points that Duke has reported that it's tracking for its interconnection process, tracking internally, and I'd just like you to answer whether Dominion also tracks these things. I'm just going to go down the list. The queue number for a project?

A Yes.

Q The capacity of a proposed facility in kW or MW?

A Yes.

Q The primary fuel type or energy source type, like solar or wind or biogas?

A Yes.

Q Whether the project is exporting or non-exporting or what the customer type is, such as net metering or a sell-all project?

A Not consistently. That information is not required currently for the quarterly reports. I will indicate that there is a difference between administration of the interconnection procedures and a tracking of the interconnection procedures.

Q And I would say that my questions are focused on whether Dominion internally notes this information in some way. Keeps track of it, is what I mean now.

A Certainly. Thank you.

Q Thank you. The city where a project is located?

A No.

Q The zip code where a project is located?

A No.

Q The substation where a project proposes to interconnect?

A Yes.

Q The feeder to which a project proposes to interconnect?

A Yes.

Q The status of the interconnection application, that is, whether it's active or withdrawn or has been interconnected?

A We actually do list that, and we include that on the quarterly reports. We've actually modified the quarterly reports to not only show if it's in active status, but also what the preliminary interdependency of the request is to give more information to the interconnection customer.

Q Thank you. The date the application is deemed complete?

A We report the date that the queue number was assigned. There can be a distinction between that and when the interconnection request is considered complete. Assuming that the interconnection request is complete upon the initial submission, then we record the -- the date the queue number was assigned.

Q For fast track eligible projects, the date that Dominion notifies the customer of the results of the fast track screen?

A We do not track that. That's an example of where we administer the process in the interconnection procedures for compliance purposes. You know, tracking, I try to emphasize with our team for tracking information that's required for their quarterly reports, the administration, the process could involve utilization of software such as Outlook calendars that our team can use to try to identify when certain compliance metrics are due, but as far as recording that in a consistent manner, I would say that that is not recorded consistently.

Q So no one writes down fast track results sent November 1st?

A Not in a database or in our spreadsheet.

Q Okay. Thank you. And so would your answer be the same for notification of supplemental review results for projects that go through supplemental review?

A Yes.

Q And what about the date that a project that goes through the Section 4 study process is notified of the system impact study results?

A That date would be recorded periodically, but I would not say that that is consistent. Again, that's in an area that we administer compliance. That would be an example where a contract administrator may put that on an Outlook calendar to try to pursue that date towards completing -- having the study completed and sending to the customer.

Q Okay.

A But as far as regularly tracking that, I would say that that is probably inconsistent at this time.

Q And, similarly, the date of notification of facility studies results?

A The -- the same, inconsistent.

Q Okay. And what about the date that the -- a final Interconnection Agreement is provided to the customer?

A The date in which the interconnection customer is sent the agreement would be recorded on a consistent basis because that is one of the parameters for the queue performance report.

Q Thank you. Just a few more. And the -- the ones that I just listed were items that Duke reports that it currently tracks. The ones I'm going to tell you now are ones, to be clear, that Duke does not currently track, just since I was categorizing the first group that way. The actual results of fast track screens, does Dominion track for each project what the outcome is?

A We don't track or record in our spreadsheet. We do make sure that we explain to the customer what the results of the fast track screens were. Often that is by email and then with follow-up discussion via the customer options meeting.

Q Thank you. And for supplemental review results, are the -- whether they pass or fail supplemental review recorded or tracked by Dominion?

A We do not track that in our spreadsheet. I will say our experience as far as supplemental review -- and I'm going to categorize into two different buckets of requests -- as far as power export fast track requests, we've had limited application of those over the past three-year period, I believe in the low 20s as far as the number of requests that would eligible for fast track. And those have all failed the screens and -- and primarily due to the aggregate generation that's already on the grid. The screens are not just the interconnection request being submitted. It incorporates the interconnection request plus the aggregate generation.

So we have found practically that if the fast track request, if it's power export, does not pass the screens, then it generally has needed a system impact study to determine thermal and voltage impact, a short circuit analysis and protection review, along with some pretty detailed estimating, which is effectively the full study process. So in our experience, we have offered the customer the opportunity to continue with the project if they so desire, but we have recommended that it be through the full study process.

The other bucket that would be applicable to the fast track process, you know, has been net metering. And we have had the majority of the net metering requests -- and I will have to qualify that this information would be subject to check because net metering, although it is administered under the same North Carolina interconnection procedures, it is administered by a different department within Dominion Energy. But from talking with that different department, we still had a limited number of applications for net metering requests as well, and the majority of that has been the less than 20 kW inverter process. And I believe over the past three-year period it's been in the range of 80 to 100 requests, and those have all been processed consistently with the procedures, you know, in a relatively short time frame.

And as far as fast track requests for net metering, again, talking with this other department, we've only had like less than five over the past, you know, three-year period, and those have been processed consistent with the time frames and the procedures, and we have expeditiously approved those.

So as far as Dominion Energy, and I know that's a long answer, but supplemental review we don't have a lot of experience with that.

Q Okay. Thank you. And does Dominion Energy track the date that it grants permission to operate?

A Yes.

Q And, finally, does Dominion Energy North Carolina track the final interconnection costs paid by the customer to the Utility?

A We don't track that in our spreadsheet. You know, certainly that's part of the final accounting process that we explain and try to, you know, explain to the customer's satisfaction.

Q All right. Thank you.

MS. BEATON: I have no further questions.

CHAIRMAN FINLEY: Mr. Smith?

MR. SMITH: NCSEA has no further questions for Dominion.

CHAIRMAN FINLEY: Kemerait?

MS. KEMERAIT: And NCCEBA has no questions for Dominion's witness.

CHAIRMAN FINLEY: Ms. Townsend?

CROSS EXAMINATION BY MS. TOWNSEND:

Q Mr. Nester, I'm Teresa Townsend. I'm with the Attorney General's Office, and I just have a few questions for you. You indicated that you are responsible for leading the team that administers the process by which interconnection customers' requests and -- are issued approval, correct?

A Yes. That's one of our roles.

Q Okay. And that team exists primarily because you have a duty under the law to interconnect with renewable energy generators. Would that be correct?

A Yes. We have a target to try to administer the interconnection procedures to accomplish the purpose of interconnecting customers to pursue a safe, reliable, and operable grid.

Q Thank you. On page 20 of your direct you testified that your company has "successfully resolved" -- dispute -- "disputes under the current NCIP." What type of disputes have arisen at Dominion?

A Could you share the --

Q Sure.

A -- excerpt in my direct testimony?

Q Yes.

A Is it page 20?

Q It's on direct, page 20. It's just your comment about having successfully resolved disputes under the current NCIP.

A So line -- beginning with line 14?

Q Right.

A And I'm sorry. Could you repeat the question?

Q No problem. What type of disputes have arisen with Dominion with these interconnection requests?

A Since 2015 -- well, let -- let me divide this, again, into two excerpts.

Q Whatever. That's fine.

A Prior to 2015 we had several disputes regarding timelines. And -- and as we presented during the 2015 stakeholder process, we did have an interconnect request study queue backlog. Since the 2015 revisions were approved and put into effect, the timeline disputes have gone down tremendously because interdependency has been very beneficial to try to communicate the order in which an interconnection request is studied relative to other interconnection requests. So the majority of disputes that we have had since the 2015 procedures were approved had been basically business-to-business disputes.

We haven't had as many to reach the informal complaint status with the North Carolina Public Staff. And we believe that the existing dispute process, you know, encourages communication between the Utility and the customer regarding basically addressing questions. And so categories since the 2015 have ranged from interconnection costs --

Q Uh-huh.

A -- that were identified from the study results. That's probably been a predominant category.

Q Okay. And how many of those were actually resolved? Were all of them resolved?

A We still have some that are current, but of -- the predominant number has been resolved.

Q Okay. And in your rebuttal testimony on page 16 you state that "DENC has found that direct communication with interconnection customers regarding the status of their specified interconnection request has been the most effective medium by which queue status and performance has been communicated and addressed." Is that your statement?

A Yes. Beginning in line 20 on page 16?

Q Yes.

A Yes.

Q Can you define for us what you consider "direct communication"?

A Certainly. The interconnection procedures themselves, we believe, encourage direct communication with the interconnection customer regarding their respective request, beginning with the inception of the request. When a customer submits an interconnection request, we communicate right away regarding a completeness evaluation and also, you know, key, a preliminary interdependency status.

We currently use transformer capacity reservation kind of as a high level as the category by which we determine preliminary interdependency status, so our contract administrators can communicate that right away. So a customer will know very quickly if they're a Project A or a Project B, or we call it a subordinate project if they're interdependent with more than one interconnection request.

As the process continues, very soon thereafter there will be a scoping discussion, and we try to involve our technical teams, particularly our distribution planning department, in those discussions. And if we have constraints already known on that electrical infrastructure, we try to communicate that directly to the interconnection customer at that time. And we've actually had a few interconnection customers that will take that information, because what we want to try to do is give them information to make a business decision, they will take that information and in some cases make a business decision and withdraw their interconnection request.

Q So are these communications done via email, via phone calls? How is the communication actually effected?

A A combination. A lot is with email. A lot is phone calls. We have several interconnection customers that have multiple interconnection requests in the queue at the same time in a combination of study or construction status, and many of them request and we try to accommodate regular conference calls so that we can go through their interconnection request and give them status updates. And if our contract administrators have feedback from our technical teams on the status of the studies or any higher cost constraints that may have already been identified, we try to communicate that to the customer at the earliest opportunity.

Q And would you say that your Company's willingness to communicate with its interconnection customers has positively impacted the resolution of your disputes and getting interconnection customers connected?

A I -- I can only speak for the Utility, but we -- we believe it's been beneficial.

Q Okay. On page 28 of your direct testimony you state in your summary that Dominion has made "significant progress in the administration of the interconnection study queue since 2015." Do you see that?

A Yes. Beginning in line 3?

Q Uh-huh. Would you agree that this progress is a sign of Dominion's recognition of the fact that distributed energy is a way to build a more redundant grid to minimize power disruption for customers?

A While that may be a consideration, our primary directive has been to administer the interconnection procedures, as ordered by the Commission, in a consistent manner, in an equitable manner from interconnection customer to interconnection customer to pursue a safe, reliable, and operable grid.

Q And, in fact, the interconnection process allows the building of a -- excuse me -- of a more robust grid and it's -- you're able to do that at the expense of the renewable energy providers. Would that be correct?

A The study process does identify grid modifications that are needed to accommodate each interconnection, and each interconnection request is --

basically requires a customized study because it's based on the electrical location of that facility. So our focus has been to identify those grid modifications that are needed.

Q Okay. Do you believe that Dominion has done a better -- or has a better record in administrating its queue than Duke Energy has?

A I -- I can only speak with issues regarding Dominion Energy.

Q Okay. Having -- have you heard the testimony of the Duke witnesses today and yesterday?

A Yes, I did.

Q Can you explain any difference in the way that Dominion processes its interconnection requests than Duke Energy has, based on that testimony?

A Again, I can only speak for Dominion Energy, but, you know, we do respect each Utility's obligation and responsibility to pursue an interconnection process that ensures the safety and reliability and operability of the grid in accordance with good utility practice. And good utility practice, we believe that it's an important principle that each Utility for its operating territory be primarily responsible for the determination of accomplishing that goal.

Q Okay. If a potential interconnection customer were to ask for information regarding all the places in North Carolina on the Dominion grid to interconnect which would require the fewest upgrades and be the least congested, does Dominion have a way for a potential customer to learn that information?

A There are some different ways that a customer can gain insight. Dominion does not provide that type of information directly, but in our quarterly provided queue status report, you know, a customer can take a look at that status report and see which substations have a lot of interconnection requests, actually which transformers have a lot of interconnection requests along with associated MW, and which substation transformers do not have a lot interconnection requests. And so there is information that is publicly available.

In addition to that, the pre-response inquiry, the Section 1.2 pre-response inquiry process, we do encourage developers to utilize that process when they do have a site of interest so that we can provide high level queue and electrical infrastructure information.

Q Thank you. One final question. In your rebuttal testimony on page 18 you state that "DENC is not opposed to investigating the potential development of a hosting capacity map tool for future application," but you do oppose it being a requirement of the NCIP; is that accurate?

A Yes. Are you referring to page 18 beginning with line 3?

Q Right. The quote is "DENC is not opposed to investigating the potential development of a hosting capacity map tool for future application" -- excuse me -- but then I've also added but you oppose it being a requirement of the NCIP based on your testimony. Would that be an accurate statement?

A That's correct. We believe that hosting capacity maps should not be a requirement of the regulation, that it should be encapsulated into the category of good utility practice, but the Company is willing to evaluate the potential for such a tool.

Q Okay. So you would agree that it would benefit DENC, its customers, and the state of North Carolina to more specifically direct generators to locations on your system that will not involve major network upgrades and/or at least not be disruptive to the grid. Would that be accurate?

A I cannot make that direct of a statement at this time. The Company is at this time just willing to evaluate the potential for a hosting capacity map, but as far as its potential benefit, I could not speculate.

Q Okay. Thank you, Mr. Nester.

MS. TOWNSEND: That's all the questions I have.

CHAIRMAN FINLEY: Public Staff?

MR. DODGE: Thank you, Chairman. I'll go ahead and get started with one line of questioning while MS. Cummings hands out an exhibit here.

CROSS EXAMINATION BY MR. DODGE:

Q Good afternoon, Mr. Nester.

A Good afternoon.

Q In your rebuttal testimony on pages 15 and 16 -- if you want to turn to that page --

A Thank you. Yes.

Q Okay. You -- you describe the -- the Technical Standards Review Group or you discuss the Technical Standards Review Group that Duke is implementing and indicate that Dominion is not committing to a TSRG type process for its interconnection management; is that correct?

A That's correct. We do not believe that the technical working group concept should be a requirement of the interconnection procedures. Dominion Energy believes that direct communication, you know, that we pursue with our interconnection customers regarding the specific interconnection requests. In that process we communicate study parameters that were utilized for each individual study, and we believe that is a -- has been an effective way to communicate with the interconnection customer.

Q Okay. Thank you. So to the extent Dominion, in its application of good utility practice, develops guidelines somewhat like, for example, Duke's Method of Service Guidelines, those would just be communicated through the -- the direct communication to customers, or is there a place the customers can review what those guidelines would -- that Dominion is applying to interconnection requests is publicly available? Where would that information be publicly available?

A We believe the study process is actually the most appropriate communication path by which Dominion Energy -- to communicate good utility practice and -- and even modifications to good utility practice. A couple of primary reasons.

You know, the study process is really identified in the interconnection procedures as the process that is needed to identify the grid modifications to accommodate interconnection. So we are very concerned, to a certain degree, of communicating study parameters in advance of actually conducting a study that may give a signal for an interconnection customer to try to do their own study and make assumptions regarding the grid modifications that might be identified. We believe that that can cause issues for that customer and for, frankly, Dominion Energy in its process, you know, as we go through the study itself.

And secondly, is when we are trying to explain the technical parameters that we utilize for a study, it has been beneficial to actually have an interconnection request against which to describe those parameters. It's not a concept. We actually communicate how the particular interconnection request measured against the parameters that we are trying to address, you know, for the safe, reliable, and operable grid.

Q All right. Thank you.

MR. DODGE: Mr. Chairman, I had asked Ms. Cummings to pass out an exhibit. Could I have that marked as Public Staff Cross Exhibit Number 1?

CHAIRMAN FINLEY: It shall be so marked.

MR. DODGE: Thank you.

(Whereupon, DENC Witness Nester Public Staff Cross Exhibit 1 was marked for identification.)

Q Mr. Nester, I'm not sure if you've had a chance to review this document or may be familiar with this document. It's just an excerpt from the Virginia Administrative Code section dealing with state jurisdictional interconnections in Virginia.

A Yes.

Q The first page is just a kind of table of contents. If you flip to the second page, the Applicability and Scope section, this indicates that these provisions apply to the standardized interconnection and operating requirements for generating facilities with a rated capacity of 20 MW or less connected to the system in Virginia; is that correct?

A Yes.

Q Okay. And then turning to the last page, just wanted to ask you a question about the dispute process on the -- the back of the packet. This is Section 100, the dispute process for interconnections in Virginia.

Now, looking about midway down that paragraph, do you -- or the page, do you see the paragraph that starts with the word "Alternatively"?

A Yes.

Q Okay. And I'll just read that real quick.

"Alternatively, the parties may, upon mutual agreement, seek resolution through the assistance of a dispute resolution service." This language is comparable to the language that's included in the -- the stipulated redline the parties agreed to on January 25th, is that correct, in terms of a third-party alternative dispute service being available?

A It does look similar, yes.

Q Do you also -- are you involved in the state jurisdictional interconnection process in Virginia in your -- your current capacity?

A Yes.

Q And how many -- can you give us a perspective how many disputes Dominion has had with interconnection customers in Virginia?

A We have had several business-to-business disputes that have not involved the SEC staff, and we've had a limited number of informal complaints.

Q And so the -- the informal complaints that involved the SEC staff, that's the Provision C where the parties can reach out to the Commission's DER staff to help resolve -- attempt to resolve that informal complaint?

A Correct.

Q Have you had any facilities at this time use a -- seek to use a dispute resolution service, a third party?

A To my knowledge, no.

Q Do you know, are there parties that have been identified that would serve in that capacity?

A To my knowledge, I'm not aware of an interconnection customer requesting this particular section in the dispute process, nor has Dominion Energy, but I've only been in this position since mid 2014.

Q Okay. Thank you, Mr. Nester.

CHAIRMAN FINLEY: Redirect?

MS. KELLS: Yes. Just a few.

REDIRECT EXAMINATION BY MS. KELLS:

Q Mr. Nester, counsel --

COMMISSIONER GRAY: Could you pull that mic --

MS. KELLS: Of course. Sorry.

COMMISSIONER GRAY: Thank you so much.

Q Mr. Nester, counsel for IREC asked you a list of pieces of information about whether or not Dominion tracks those internally or not. Do you recall those questions?

A Yes.

Q And I think most of counsel's questions were about internal tracking as opposed to reporting, but could you speak briefly to the Company's position as to why it does not believe it would be appropriate to impose additional reporting obligations?

A Certainly. We believe that additional reporting obligations would actually be detrimental to the processing of the queue for Dominion Energy. Under good utility practice we have tried to administer the procedures consistent with the sections and the time frames. We have also utilized a very manual process. Again, that was based off of the level of interconnection requests and also the focus to try to administer our study backlog and -- and deal with the study backlog in 2015 in as timely of a manner as we can.

So we actually utilize a spreadsheet to track our interconnection requests, and the spreadsheet was designed with each column to represent a process step initially. And at the time of development I wasn't sure if I was going to be doing a tracking of North Carolina requests only or tracking Virginia requests, so I designed it somewhat concurrently, so it goes from column A to column BV, so we can't really print it.

But, again, you know, while it is a manual process, it has been effective to address our interconnection queue, to communicate with customers, and to administer the reporting on a quarterly basis that was ordered by the Commission in 2015.

Q Thank you. And so -- and you just mentioned that that process has been effective. Would you also say that it continues to be effective to this day?

A It -- it continues to be effective. The reporting is a manual process as well. We pull information that we attempt to consistently track, and that's where I spoke of the differentiation between tracking the process steps and administering the process steps. I would say that we administer the majority of the processes that are included in the NCIP, and there are many. We track those process steps for which reporting is required, and our goal is to be compliant with the Commission Order.

Q Thank you. Counsel for the Attorney General's Office asked you a couple questions regarding your statement in your direct testimony about the significant process that Dominion has made in its study queue processing. Just a quick follow up on that. When the Company is proceeding under the North Carolina procedures to process an interconnection request, would you agree that your focus at any one time is on the individual interconnection request that you are addressing and not a larger picture of, you know -- except for the cases of interdependent facilities, you're focused on -- you take each request and you look at its impact on the grid and other facilities on its own?

A That's correct. Each interconnection request gets an individualized study that takes in consideration or tries to anticipate its impact on the grid, along with the aggregate generation that is on the grid.

Q And you spent some time in your -- both your direct and rebuttal testimony talking about good utility practice, and there were some questions about that. Would you agree that the -- the Company's determination of good utility practice -- I think you touched on this in some questioning with regard to the Attorney General's Office -- the determination of good utility practice is unique to each utility and its -- the unique characteristics of its service area?

A Yes. Each utility has different operating characteristics, different voltages in which they serve customers, particularly at the distribution grid, and frankly, different safety practices as well, which, you know, ultimately safety is number one, you know, with Dominion Energy and the utility business.

Good utility practice recognizes the regulatory obligation of a public utility in the operation of its grid and to, again, to pursue a safe, reliable, and operable grid. And we believe that given the specific operating characteristics involved with each utility service territory that it's appropriate for that utility, while it can gain information from other utilities or other working groups, which, you know, Dominion participates in IEEE and various working groups across the -- the country in this industry, ultimately, we believe that each utility is responsible for determining good utility practice as it applies to their service territory.

Q Just a last question or two. Counsel for the Attorney General also asked you about, you know, benefits that might be associated with directing interconnection customers to certain places on the grid to place their projects. Would you agree with a characterization of Dominion's North Carolina service area as a saturated -- as a distribution system saturated with distributed energy?

A I would certainly say looking --

Q On particular -- I'm sorry -- on particular -- at particular locations?

A I would certainly say looking at our quarterly status reports, if you were to look at the substations and circuits that repeat, that there are definitely saturated areas in our service territory.

Q Okay. Thank you.

MS. KELLS: That's all I have.

CHAIRMAN FINLEY: Questions by the Commission? Commissioner Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Nester, it's my understanding from the testimony of several of the other witnesses that Dominion regularly accepts surety bonds as financial security for purposes of when a deposit is required under the interconnection procedures; is that correct?

A That is correct.

Q And has done so for some time?

A Yes.

Q What's been your experience with working with surety bonds?

A Well -- and, again, I'm not a financial security specialist, but what we try to do from a procedure standpoint is to be consistent with the Company's policies regarding acceptable financial security for electric service deposits which currently is either cash, irrevocable letter of credit, or a surety bond. And so where we do have occasion that a customer has requested surety bond for interconnection facilities, we accept that as a potential because the interconnection procedures indicate that it is an -- as long as it is consistent with the Utility's credit policies -- and we do believe that that is an important criteria, that it be consistent with the specific Utility's credit policies in order to be an acceptable financial security.

But we will take that -- we will actually provide a surety bond form to the customer, and upon return of that form and any information from the insurance company, we will submit that to our system credit department for review to determine if it was an acceptable financial security.

Q Are you aware of any -- have any problems surfaced that have come to your attention about financial security posted in the form of a surety bond? Are you aware of any problems?

A Not at this point in time.

Q Mr. Nester, I'll -- I'll ask you this question and in the -- using the form that the Chairman used with Duke Energy. I take it -- you testified that you've had great success in reducing your case -- your pending caseload since 2015. I take it you haven't had -- used a silver bullet to do that; you've used a lot of buckshot. Would I be correct?

A We have -- we do believe that the interconnection procedures have been effective, and we have made, you know, additional increments in staffing and also in practices to administer the queue.

Q Well, that's -- that's really what I want to -- want to focus on, is can you identify in -- what, in your judgment, are the salient -- most salient changes that have been most beneficial to you in working down your caseload? Additional staffing you've mentioned.

A Well, actually, it started with the Commission Order in 2015 for the initial queue management initiatives, where we had a somewhat application or retroactive application of an increased security deposit and proof of site control to anyone who existed in the study queue that had not yet received or not yet executed an Interconnection Agreement.

At that point in time we had 86 requests that fell into that category, and after the implementation of the queue management initiative, we had 25 of those requests to either cancel or have their queue position withdrawn. So, you know, that was beneficial. And then probably the largest beneficial aspect was the preliminary interdependency, so Section 1.8 in the NCIP.

Prior to that, regardless of when a customer submitted their application request and the number of requests that were in the queue on a particular substation or circuit, the expectation was to get a study report within the time frames that were in the procedures, and electrically that's just not possible. You need clarity on the earlier queued projects before you can -- meaning that you need to know if they're going to go forward into construction and be connected or are they going to withdraw -- before you can effectively study the next people in line that are trying to connect to that same infrastructure.

So by having that Section 1.8, again, we were using the substation transformer capacity as the initial preliminary interdependency determination, and we were able to readily assign a customer to be a Project A, Project B, or a subordinate project, and we try to ensure on a regular basis that the customer knows what their interdependency status is. What we have found practically is, you know, Project As need to make a pretty timely decision according to the time frames in the procedures. Project Bs have been a little bit more challenging, frankly, because we're doing a with and without Project A study, and they cannot go to an Interconnection Agreement until the Project A determines if they're going to move forward or not.

But the subordinate projects, they have understood by the procedures, you know, where their queue position is. And, you know, we communicate when they get to a Project B status and, you know, a System Impact Study Agreement can be executed at that time so the study can proceed, and that has been very, you know, extremely beneficial.

Q How -- how has it been beneficial for you to set up the interdependency structure when I understood from some of the Duke witnesses that that may be one of the features that -- that prolongs their queue in North Carolina for -- in their service territories? How -- how did creating that interdependency structure benefit you in clearing your caseload?

A And, again, I -- I can only speak to Dominion Energy.

Q That's all I'm asking you to do.

A But what we utilized for determining the preliminary interdependency and recognizing that the preliminary interdependency can change once it goes through system impact study, as indicated in -- in the procedures, but by using the transformer capacity, we were able to basically tell every customer who was in active study status what their queue position was far as the order of study. If they were Project A, then, you know, they proceeded through the -- the time frame in an orderly manner, not to say that there aren't questions.

The subordinate projects, probably the -- the largest communication there is we still try to give them high level queue information, you know, to let them know, very similar to information that would come from a pre-request response to Section 1.2, which is, you know, the closest three-phase electrical infrastructure, the size transformer that's in the substation, how far they are from the substation, how many requests that we have in the queue and the total MW.

And in some cases those subordinate customers have recognized that somebody along the line in their list of -- in the list of applicants to a particular substation is going to have to pay for a pretty major upgrade, and they may make a business decision that they don't want to wait that long to see if that occurs. And in some cases, you know, if -- if the customer is like the first subordinate customer, for example, they can tell that the Project A and the Project B, if they go forward, will utilize the transformer capacity and -- and it could be a significant upgrade for the subordinate project.

So, again, our focus has been to try to give as much readily available business, you know, electrical infrastructure information to even the subordinate customers so that they can make, in some cases, a business decision before they even get to a study process.

Q Thank you for that. Were there -- are there other things that stand out in your mind that were significant -- of significant importance in helping you get rid of your backlog? You mentioned some administrative changes. What would you -- what would you include into that heading?

A In -- in that heading it's somewhat of our organizational structure. We have contract administrators that are assigned geographic service territories as well as developers that have a significant number of requests in the queue, and -- and we do that for a few purposes. One is, we are spread out throughout our system and we do deal with three jurisdictions for distribution voltage interconnection requests.

I do need to clarify that my group only deals with the distribution -- the parallel generation requests for the distribution grid. PJM, our regional transmission operator, administers the queue for all transmission interconnection requests, as well as any FERC jurisdictional interconnection requests at distribution in -- in accordance to PJM's determination.

But our organization is set up to where contract administrators will basically serve as a primary interface to customers in the study process, and they focus on providing regular communication to customers to provide them status updates, particularly if they're a Project A or Project B, and try to address questions that the interconnection customer may have either as they get study results back or just expectations.

Subordinate projects, you know, they are formed early on, and most of them are aware of the interconnection procedures that indicates that the study process isn't to occur or begin until they get at least to be a Project B status. But we still try to reach out to them periodically as well just to see the status of their project because we recognize the interconnection, while it's very important, the interconnection study process, it's only one aspect that the developer has to address to determine if their project is viable.

Q I understand you may have people who work across multiple jurisdictions, so I -- I guess I would want you to translate the answer -- the question I'm going to ask you into a North Carolina FTE type concept. So how many staff do you have and contract staff either on payroll or on contract that you would say are assigned to interconnection processing -- request processing from North Carolina?

A I'm sorry. I don't have that information.

Q That's not --

A I do have information that shows incremental staffing, that we have, you know, grown since the 2015 procedures, but I don't have information regarding the -- the total staffing. I -- I do know we --

Q Is that because it is, in fact -- the people are assigned to multiple jurisdictions and work across state lines? Is that -- is that --

A Yes. And we utilize our technical internal teams to do the study process, so distribution planning, for example --

Q Okay.

A -- will do --

Q I understand.

A And -- and it's spread out to different organizations.

Q I didn't know whether you would have it or not. I just thought I would ask.

A I'm sorry.

Q Thank you.

COMMISSIONER CLODFELTER: That's all.

EXAMINATION BY CHAIRMAN FINLEY:

Q Mr. Nester, how does the production of the distributed energy resources in your North Carolina service territory compare with your load in that service territory? Do you know?

A And, again, I'm -- I'm not the subject matter specialist, so this is subject to check, but I believe in our -- one of our recent reviews the average load in Dominion service territory was around 570 MW. And as I indicated, and this is just for state jurisdictional non-net metering interconnections, as of January 24th we had connected 488 MW. But we also have 95 MW of FERC jurisdictional interconnections that are connected at a distribution voltage as well, which we have begun to include in our quarterly reports at the request of the Public Staff, and are agreeable to continue to incorporate that into our quarterly reports and -- and our annual reports.

And then there have been additional MW of generation connected -- renewable generation connected at the transmission grid as well administered by PJM

Q So you've got more output of the renewable energy resources in your North Carolina territory than you've got load in?

A We do as far as average load. And I'm not sure what the comparison is regarding peak load, but we -- certainly, it has been significant.

CHAIRMAN FINLEY: All right. Those are the questions that I think the Commission has. Are there questions on the Commission's questions? Yes, ma'am.

MS. BEATON: I just have one quick question for you.

EXAMINATION BY MS. BEATON:

Q You mentioned not tracking certain things. I just wanted to know, how much time does it take a -- it would take a Dominion employee to enter a date into a spreadsheet, say, you know, the date a certain study was completed?

A I probably don't have a quantifiable time frame, but I will address that process from a process standpoint. Our current process, and -- and we are --

while we don't believe that, you know, a web-based product or even a software-based product, you know, should be mandated by the -- the regulations, you know, we believe that that falls underneath a good utility practice concept for each Utility to, you know, gauge when -- the administration of the queue or the growth of the queue and -- and somewhat spurs that development. I will say that Dominion is very willing to evaluate the potential, you know, for a software product.

But even if a software product were utilized, each reporting requirement that is added to the process, and if it involves each step of the interconnection procedures, when that is done for every request that exists in the queue and it goes through the process -- and in many cases there are modifications being administered, there are subprocesses that also have compliance periods -- each time that is added to the process, I'm taking time away from my administrators and my project managers and my customer billing administrator to focus on communicating with that interconnection customer because when they are doing that, they are typing into a spreadsheet. Many cases they may be talking to our technical teams to try to confirm what date it actually was, because in some cases we have developers that submit an interconnection request, but then they come back and say, well, this inverter is obsolete, you know, we'd like to submit a modification inquiry to change our inverters, and we evaluate that in accordance with the modification inquiry process. And it may, you know, do a little bit of a start/restart type process.

So I'm very concerned about reporting requirements because it will take time away from our department in administering the interconnection procedures.

MS. BEATON: I don't have any more questions for you.

MS. KELLS: Can I ask a question on that since it wasn't really in direct response to Commission questions?

CHAIRMAN FINLEY: Yes, ma'am.

FURTHER EXAMINATION BY MS. KELLS:

Q Mr. Nester, while conceivably it might take a short amount of time for one of your employees to enter in a piece of data into a spreadsheet, would you agree that over time, taken together, you know, all of the projects you all deal with, that would be an additional -- it would be an additional administrative burden?

A Yes. And, you know, the Company has been providing the quarterly reports, as ordered by the Commission Order in 2015, since the inception. The reports have been publicly available on the Commission website. But in practicality, we have received a very limited number of inquiries regarding our quarterly reports from interconnection customers. I'd say a handful at best. And, you know, we believe that that level of reporting that is currently provided, you know, can provide some information that's beneficial, but the -- the primary benefit is really the study process itself. You know, the pre-application, you know, the pre-response inquiry, and particularly we think that has been very beneficial. We don't track the number that we have received, but we do administer the -- the processes.

Q And wouldn't you agree that having -- you know, entering in the data also depends on that data being correct and being in the right place and being provided on time and many other factors; rather, it's not always just a matter of having a number in front of you to input?

A Oh, very definitely so. I actually prepare the quarterly reports myself, and I try to do that to remove some administrative burden from my team so they can focus on the interconnection procedures and interconnection customers. And part of the process that I utilize to do those reports is to review all the entries that were made throughout the quarter, compare them with the previous report for consistency, and try to address any potential discrepancies or questions. And even for the existing, you know, reports, you know, there are several data fields that need to be crosschecked, and that does involve time.

Q Thank you.

MS. KELLS: That's all.

CHAIRMAN FINLEY: All right. Without objection, we will admit into evidence Mr. Nester's Exhibit 1 and the Public Staff Cross Examination Exhibit.

(Whereupon, DENC Exhibit MJN-1 and DENC Witness Nester Public Staff Cross Exhibit 1 were admitted into evidence.)

CHAIRMAN FINLEY: And Mr. Nester, you may be excused.

THE WITNESS: All right. Thank you.

CHAIRMAN FINLEY: Thank you for coming. What about this Agreement and Stipulation of Partial Settlement? Does anybody want to introduce that into evidence in this case?

MR. JIRAK: Yeah. With your permission, we'd like to move the Stipulation into evidence. Our copy has been filed with the Commission. We'll provide a hard copy.

CHAIRMAN FINLEY: All right. Objection? Any objection?

(No response.)

CHAIRMAN FINLEY: Without objection, the Stipulation will be entered into evidence.

(Whereupon, the Agreement and Stipulation of Partial Settlement by and between Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Dominion Energy North Carolina, North Carolina Pork Council and the Public Staff - North Carolina Utilities Commission was admitted into evidence.)

CHAIRMAN FINLEY: All right. IREC, call your witness.

MS. BEATON: Mr. Chairman, before I call my witness, there were a few preliminary matters --

CHAIRMAN FINLEY: Yes, ma'am.

MS. BEATON: -- I wanted to deal with. First off, the parties stipulated to have IREC's other witness, Mr. Brian Lydic's, rebuttal -- direct and rebuttal testimony admitted into evidence, so now I would like to move to have Mr. Lydic's direct and rebuttal testimony and the attached exhibits move into evidence --

CHAIRMAN FINLEY: All right.

MS. BEATON: -- moved into the record.

CHAIRMAN FINLEY: Mr. Lydic's direct testimony consisting of 35 pages of November 29, 2018, and his four exhibits are entered into evidence.

(Whereupon, the prefiled direct testimony of Brian M. Lydic was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits BL-Direct-1-4 were identified as premarked and admitted into evidence. The confidential page of BL-Direct-3 was filed under seal.)

## I. Introduction

**Q. Please state your name, title, employment, and business address.**

A. My name is Brian M. Lydic. I am employed by the Interstate Renewable Energy Council, Inc. ("IREC") as a Regulatory Engineer. IREC's business address is P.O. Box 1156, Latham, NY 12110-1156.

**Q. For whom are you testifying?**

A. I am testifying on behalf of IREC.

**Q. Please describe IREC.**

A. IREC is a non-partisan, non-profit organization working nationally to increase consumer access to sustainable energy and energy efficiency through independent fact-based policy leadership, quality workforce development, and consumer empowerment. IREC works to increase the adoption of policies and regulatory reforms that expand access to and streamline grid integration of distributed energy resources to optimize their widespread benefits. The scope of IREC's work includes updating interconnection standards to facilitate deployment of distributed energy resources ("DER") under high deployment scenarios. IREC has recently been or is currently involved in similar interconnection proceedings in Illinois, Ohio, South Carolina, Massachusetts, California, Iowa, Minnesota, Maryland, Nevada, and Hawaii. IREC also participated in the proceeding at FERC to revise the SGIP. In addition, IREC has published Model Interconnection Procedures, which capture best practices with respect to interconnection, and has also published reports on other interconnection policy issues.

**Q. Please describe your current work duties, work experience, and educational background.**

A. I have been employed as a regulatory engineer for IREC since August 2017. In my role with IREC, I provide engineering expertise in regulatory proceedings, stakeholder working groups, and standards working groups to help advance the integration of DERs. I have acted as chairman of the Forum on Inverter Grid Integration Issues since its founding in February 2013, which has developed inverter test procedures used by research institutions and utilities. I am a member of IEEE and the IEEE Standards Association, a member of the IEEE 1547 and 1547.1 working groups, and I am a Standards Technical Panel member for UL 1741 and UL 1699B. Prior to working for IREC, I contributed to standards development (including IEEE 1547/1547a, 1547.1/1547.1a, UL 1741, and NEC) and interconnection proceedings (including the California Smart Inverter Working Group and Hawaii Advanced Inverter Technical Working Group) on behalf of my previous employer, the inverter manufacturer Fronius USA, LLC. While with Fronius, I helped develop non-exporting requirements for Hawaiian Electric Rule 22 and California's Rule 21, and worked with Hawaiian Electric to create a self-certification regime for non-exporting equipment. I hold a Bachelor of Science in Electrical Engineering from the University of Michigan. My CV, which further details my experience, is attached as **Exhibit BL-Direct-1.**

**Q. Have you previously testified before the North Carolina Utilities Commission?**

A. No.

**Q. Have you previously testified before any other State Public Utilities Commissions?**

A. Yes. I have presented testimony before the Public Utilities Commission of Nevada.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

1. **Exhibit BL-Direct-1** – Curriculum Vitae of Brian M. Lydic
2. **Exhibit BL-Direct-2** – Duke Fast Track Statistics
3. **Exhibit BL-Direct-3** – Duke Energy Carolinas, LCC and Duke Energy Progress, LLC's responses to Public Staff Data Request No. 4-8
4. **Exhibit BL-Direct-4** – Email between Jessica Whitaker, Duke Energy, and Laura D. Beaton, attorney for IREC, dated August 28, 2017; and email between Jessica Whitaker, Duke Energy, and Brian M. Lydic, IREC, dated September 7, 2017

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain IREC's position on certain proposed revisions to the North Carolina Interconnection Procedures ("NCIP"). Specifically, my testimony focuses on IREC's positions that have a technical component.

**Q. Please summarize your key points.**

A. In this testimony, I explain some of IREC's recommendations for revisions to the NCIP, with a particular focus on proposed revisions that have a technical basis or justification.

First, my testimony explains why Duke Energy Carolinas, LCC and Duke Energy Progress, LLC (together, "Duke") have been applying Fast Track Screen 3.2.1.2 too narrowly and proposes a revision that will ensure this screen is applied in a way that achieves the goals of Fast Track going forward. Additionally, I explain why the Commission and the parties may want to consider revising Screen 3.2.1.7, in light of Duke's current practices of loading protective devices up to 100% of their ratings.

Second, my testimony explains why a Fast Track eligibility limit of 500 kW on lines under 5 kV is appropriate.

Third, my testimony explains why the Commission should adopt defined supplemental review screens like those in the Federal Energy Regulatory Commission ("FERC") Small Generator Interconnection Procedures ("SGIP"). I also explain why IREC's proposed defined supplemental review screens are flexible and that Duke's current supplemental review screening process could be accommodated under them.

Fourth, my testimony discusses my experiences participating in various states' interconnection technical working groups, and why North Carolina should adopt a similar process.

Fifth, my testimony explains why the NCIP should be revised to accommodate interconnection of energy storage by ensuring that projects are studied as they actually operate.

Sixth, my testimony explains why the Commission should establish a process for adoption of IEEE 1547-2018.

Seventh, and finally, my testimony explains why there should be a path to interconnection for non-certified devices.

## II. Fast Track Screens

### A. Screen 3.2.1.2

**Q. What is the purpose of Fast Track Screen 3.2.1.2?**

A. Screen 3.2.1.2 is also known as the "15% of peak load screen." A project passes this screen if

> the aggregated generation on the circuit [does] not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.[1]

The purpose of this screen in the Fast Track process is to set a "low penetration level" where higher penetration effects need not be accounted for or studied. Specifically, the idea behind this threshold is that "unintentional islanding, voltage aberrations, protection miscoordination, and other potentially

[1] NCIP § 3.2.1.2.

negative impacts are unlikely if the amount of D[istributed] G[eneration] capacity is significantly smaller than feeder capacity and always less than feeder load."[2]

These negative impacts are avoided if the DER does not feed more power into the grid than the feeder's minimum load—that is, the time of lowest demand on the relevant line section. Fifty percent of minimum load is sufficient to ensure a high likelihood that there will be no unintentional islanding, voltage deviations, protection miscoordination, or other potentially negative impacts because the combined DG on a line section is always less than the minimum load. Because minimum load data were not readily available at the time that the screen was developed, but peak load data were, the 15% of peak load screen was designed to function as a proxy for 50% of minimum load. This is because, for typical distribution circuits in the United States, minimum load is approximately 30% of peak load.[3] The actual ratio varies depending on many factors such as the type of load served. Based on this generalization, the 15% of peak load penetration level (one half of the 30%) was selected as a conservative penetration level for general screening purposes.[4]

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[2] R.J. Broderick & A. Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV*, Interconnection Studies, Photovoltaic Specialists Conference (PVSC), 2012 38th IEEE, 10.1109/PVSC.2012.6317712.

[3] M. Coddington, et al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratories (Feb. 2012), at 2, *available at* https://www.nrel.gov/docs/fy12osti/54063.pdf.

[4] *Id.* at 2.

**Q. To your knowledge, how has Duke applied Screen 3.2.1.2, and what is your opinion on Duke's application of the screen?**

A. During the stakeholder process for revisions of the NCIP, Duke shared information with the stakeholder group (included as **Exhibit BL-Direct-2**) that revealed that 98.5% of projects in Duke Energy Progress ("DEP") territory and 97.8% of projects in Duke Energy Carolinas ("DEC") territory failed one or more Fast Track screens. In particular, 63 out of 65 projects in DEP territory and 86 out of 99 projects in DEC territory failed Screen 3.2.1.2.

Upon reviewing the Fast Track screen results provided by Duke, IREC and other stakeholders discussed the issue with Duke during a series of working group calls, of which I was a participant. From these calls and data provided by Duke (*see* **Exhibit BL-Direct-3 & Exhibit BL-Direct-4**), I learned that it appears that the reason so many projects are failing Screen 3.2.1.2 is because Duke is interpreting it very narrowly, in a manner that results in many more small projects being directed to Supplemental Review than is typically seen in other states. Information shared by Duke indicates that this same screen is failed by the vast majority of projects in its South Carolina territories, too. Specifically, in DEP's territory in South Carolina, 33 out of 35 projects failed this screen; in DEC's territory, 183 projects failed this screen (though it appears there is a math error in the table, as the total number of projects listed is 179). Because South Carolina has significantly lower penetration of distributed energy compared to North Carolina, this further indicates that the problem is the way the screen is being applied—not that North Carolina is experiencing such high penetration that the screen cannot be passed. Even in states with much higher penetration than North Carolina, such as California, this screen is still regularly passed. Further, the fact that nearly all of these projects eventually passed Supplemental Review after failing Fast Track indicates that the screen is not being applied optimally to achieve the purpose of having a Fast Track process.

Because the screen looks at whether the aggregated generation on the circuit exceeds 15% of the *line section* annual peak load, the definition of "line section" is key. The screen currently includes this definition: "A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line." During the stakeholder process, Duke explained, and provided examples indicating, that its standard practice in selecting the line sections for evaluation of this screen is to select the first upstream sectionalizing device, which is often a fuse at the distribution transformer near the proposed location of the DER seeking to interconnect. The first upstream sectionalizing device likely accounts only for the DER itself and a very small portion of the load on the feeder. And obviously, when you look at only the DER's generation and a small amount of other load, a project will almost always exceed 15% of such a small line section's peak load. The next upstream device from the distribution transformer may in many cases be a lateral fuse or breaker that could also account for only a small portion of feeder load.

This narrow application of the screen has made the Fast Track review process ineffective in North Carolina. Specifically, Duke's application of Screen 3.2.1.2 undermines the purpose of Fast Track by screening out many projects that could be safely interconnected, without the need to modify the project or make grid upgrades. It is true that any switch or fuse on the system is a potential sectionalizing point, but selecting the first upstream sectionalizing device, which is generally on the nearest transformer, does not serve to identify whether significant impacts could be created on the distribution circuit. Given that such a small portion of the feeder load is accounted for in Duke's application of the screen, many relatively small systems (even <20 kW systems) are likely to fail the screen and Fast Track.

It is my opinion that the high percentages of failed projects are surprising and unusual, as Fast Track is used successfully in the vast majority of states with interconnection procedures. Even those states with some of the highest solar penetration in the country, like California, are still able to utilize the Fast Track process with a substantial portion of systems passing the screens. IREC carefully tracks how interconnection is proceeding in each state we work in, and based on this knowledge, it is my understanding that the only state where small projects are consistently failing this screen is Hawaii, which has unprecedented levels of penetration across the state. In contrast, the ability of the California utilities to process most NEM applications in a matter of days (they average less than five days) is evidence of passage of this and other Fast Track screens.

**Q. How should Screen 3.2.1.2 be applied?**

A. It undermines the purpose of Fast Track to apply an unnecessarily restrictive interpretation of Screen 3.2.1.2, which, as I have explained, is already quite conservative. Applying the screen in this manner is not necessary to protect the safety and reliability of the system. First, applying Screen 3.2.1.2 too narrowly does not provide any added value. Voltage, thermal, protection, or unintentional islanding issues would not be missed in the Fast Track screening process if this screen were applied more generally at a higher level, as is done at other distribution utilities. Another screen—Screen 3.2.1.9—is already intended to address localized issues on low voltage shared secondaries, where customers could possibly be subjected to power quality issues (such as high voltage) when DER is exporting. Screen 3.2.1.2, in contrast, is intended to evaluate larger scale issues (e.g., voltage, thermal, protection, unintentional islanding) caused by backwards power flow through the distribution system on medium voltage (MV) lines. At DER penetration levels below minimum feeder load, there is much less likelihood of backwards power flow through a significant portion of the distribution circuit, as loads located along the circuit and downstream of DER will utilize the exported power. However, if a small enough section of circuit is selected for analysis, the likelihood of backwards power flow through that section increases. In the boundary condition of selecting a line section directly at the proposed DER's Point of Common Coupling ("PCC"), Screen 3.2.1.2 would certainly not be passed, though this would give the utility no information about whether or not the DER would cause negative effects on the distribution system. Lack of backwards power flow on a larger section of the circuit would indicate that steady-state voltage issues are unlikely to arise. To analyze whether issues are likely to arise due to backwards power flow, a balance must be struck between selecting too small and too large a line section, as appropriate for the interconnected location of the DER.

Due to the low amount of aggregate DER power compared to feeder capacity, power quality concerns (such as flicker and rapid voltage change) or thermal constraints will not be encountered if Screen 3.2.1.2 is passed when reviewed at a larger line section than Duke currently does. While protection issues are also unlikely to arise if Screen 3.2.1.2 is passed at a larger line section, they will be additionally screened by Screens 3.2.1.6 and 3.2.1.7. Due to inverters' anti-islanding protection, unintentional islanding risk does not generally need to be evaluated. Power balance, and thus an unintentional island, will not be achieved if the aggregate rating of inverter-based DER is less than the minimum load on a line section. Screen 3.2.1.4 additionally screens for unintentional islanding risk due to potential interaction with rotating machines. Thus, potential issues dealing with voltage (steady state as well as flicker and rapid voltage change), thermal, protection, and unintentional islanding are dealt with effectively utilizing a larger line section for review under Screen 3.2.1.2, and in conjunction with the other Fast Track screens.

Automatic sectionalizing (interrupting) devices, such as line reclosers, should be used in the screen as convenient points that break up a feeder, where islands could form and where load data may be available. While some engineering judgement must be used to identify the relevant sectionalizing device, it should be readily apparent which sections contain the DER and load downstream from a device. In order not to restrict the analysis to too small a section, I recommend that the first recloser upstream of the DER on the primary feeder be utilized as the relevant device. If no reclosers are upstream of a DER, then the substation circuit breaker would be utilized. Once the relevant device is selected, the aggregate DER and load located between that device and the end of the feeder would be analyzed for the 15% criterion.

**Q. How should the NCIP be revised to ensure Screen 3.2.1.2 is applied properly?**

A. IREC recommends that further explanation be added to NCIP Screen 3.2.1.2 to ensure that utilities apply the screen utilizing a feeder section that includes a larger portion of the entire feeder load. Specifically, IREC recommends the following clarifying footnote be added to Screen 3.2.1.2, as set forth in the redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2**:

> A. If the point of common coupling is downstream of a line recloser, include those medium voltage (MV) line sections from the recloser to the end of the feeder. If the 15% criterion is passed for aggregate distributed generation and peak load at first upstream recloser, then the screen is passed.
>
> B. If the point of common coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak load for the whole feeder, then the screen is passed.

Note that this language has been revised since IREC's original proposal during the working group process, but achieves essentially the same purpose as our earlier recommended language, without any risk of unintentionally changing the meaning of the screen.

IREC also recommends revising the definition of "line section" in Attachment 1, Glossary of Terms, as set forth in the redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2**:

> **Line section** – A portion of a distribution circuit bounded by an automatic sectionalizing device and the end of the feeder. When applying this to the 15% of peak load screen described in Section 3.2.1.2, the smallest line section to be evaluated should begin at the first line recloser or circuit breaker upstream of the Point of Interconnection.

These changes would uphold the intent of the screen. With these changes, the relevant sectionalizing points would include the substation breaker, any mid-feeder reclosers, and the end of the primary feeder. This approach would also align better with practice by other utilities that deal with large numbers of DER interconnection requests and do not have as many relatively small projects failing this screen.

**Q. Has the clarifying footnote for Section 3.2.1.2 and revised definition of "line section" been adopted in any other jurisdiction?**

A. No.

**Q. Why has the clarifying footnote for Section 3.2.1.2 and revised definition of "line section" not been adopted in any other jurisdiction?**

A. To my knowledge, no other jurisdiction has experienced the high failure rate of screen 3.2.1.2 like North Carolina has, nor has there been any indication that any other utilities are applying this screen as restrictively as Duke is. Thus, there has been no need before now to develop a clarifying footnote or to revise the definition of line section.

**Q. How did IREC develop the clarifying footnote for Section 3.2.1.2?**

A. To clarify the intent and use of the screen, I consulted with Sandia National Laboratory, a Southern California Edison distribution engineer, and the Electric Power Research Institute ("EPRI"). Based on these conversations, review of EPRI's recommended updates for the screen in the New York State Standardized Interconnection Requirements, and further consultation with EPRI, I developed for IREC a simple set of recommendations to guide the process of defining a line section for screening purposes. To align with the "Fast Track" screening concept, the footnote was kept simple with an attempt to utilize easily identifiable information available to the utility engineer.

**Q. How did IREC develop the revised definition of "line section"?**

A. The definition is similar to that given in the California Interconnection Guidebook, SGIP screen 2.2.1.2., and a paper on the subject by Broderick and Ellis.[5]

<u>B. Screen 3.2.1.7</u>

**Q. What is the purpose of Fast Track Screen 3.2.1.7?**

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[5] R. Broderick, A. Ellis "Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies" 2012 38th IEEE Photovoltaic Specialists Conference.

A. This screen is intended to ensure that protective devices are not overloaded. It gives a wide safety margin to ensure that if DER are contributing to a protective device nearing its short circuit interrupting capability, the interconnecting DER (and future DER proposed to interconnect on the same circuit) will be studied more thoroughly. If the screen is failed, the engineer can determine if the extra fault current presented by the proposed DER would cause the protective device to exceed its rating and if an upgrade would be required.

**Q. To your knowledge, how has Duke applied Screen 3.2.1.7, and what is your opinion on Duke's application of the screen?**

A. From information given in communications with Duke and in Duke's discovery responses (*see* **Exhibit BL-Direct-3 & Exhibit SBA-Direct-8**), the utility does not appear to be misapplying the screen. However, given the high rate of failure, and the admission that the device would be loaded to a level higher than 87.5% in absence of DER, the screen should be reviewed such that it aligns with utility practice. Without additional data, it is challenging to say how often the 87.5% of device rating is exceeded without other DER on the circuit significantly contributing to the loading of the device. Given that failure of this screen could be commonplace, further analysis is warranted.

**Q. Should the NCIP be revised to ensure Screen 3.2.1.7 is applied properly?**

A. Yes. The 87.5% metric should be revised based on Duke's practice. Because Duke typically utilizes protective devices up to 100% of their rating, the screen should be revised to use a relevant percentage less than 100% but more than 87.5% that captures whether or not the device is near its rating. Given the minimum voltages used by Duke in each class, we can determine how much maximum fault current a Fast Track eligible inverter-based DER can contribute. We will assume 4.16kV as minimum for the 5kV class and 7.2kV as minimum for the 5 - 15kV range. Using a 1.25 fault current factor, a 500kW inverter-based DER at 4.16kV would contribute maximum 87A fault current. This is less than 1% of a 10kA rated device.

A 2MW DER would contribute maximum 200A at 7.2kV, which is 2% of a 10kA rated device. If 12.47kV were the lowest 5 - 15kV voltage utilized by Duke, a 2MW DER would contribute 116A or just over 1% of 10kA. These percentages would be double for 5kA rated devices. So ensuring 1.5-2% of headroom (or 3-4%) should be sufficient, depending on Duke's distribution designs. Setting the metric of Screen 3.2.1.7 at 96% of short circuit interrupting capability would provide a wide safety margin, but this issue should be discussed further, considering Duke's typical voltage levels and protection ratings.

## III. Fast Track Eligibility

**Q. Describe IREC's recommendation for determining whether projects are eligible for Fast Track review.**

A. IREC recommends that the size limit for Fast Track eligibility on lines with a voltage of < 5 kV, regardless of location, be raised to accommodate projects of up to 500 kW. This proposed revision is reflected in IREC's proposed redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2.**

**Q. Why should the eligibility limit for projects proposing to connect to a <5 kV line be raised from 100 kW to 500 kW?**

A. The current limit of 100 kW is overly conservative, and may unnecessarily send relatively small projects, mostly net energy metering ("NEM") projects, to full study. The purpose of limiting Fast Track eligibility by size is to filter out projects that would be highly unlikely to pass the Fast Track screens and Supplemental Review, and instead direct them immediately towards the study process. The technical screens are robust enough to identify projects needing study, and the size eligibility limits do not need to duplicate or go beyond the screens. In other words, the screens will catch projects that are "too large," and thus the purpose of the eligibility limit is simply to improve administration of the rules. It is not centrally a safety or reliability limit.

Even with a maximum load of 480A at 4.16kV, a 500kW DER with maximum output of 69A could possibly pass the 15% of peak load criteria of Screen 3.2.1.2, and the other Fast Track screens would check for additional issues such as protection concerns.

This 500 kW eligibility limit was adopted by FERC after a stakeholder process, and has been adopted by nearly every state that has adopted the updated FERC SGIP, including California, Massachusetts, New York, Ohio, Illinois, Iowa, and Minnesota.

## IV. Supplemental Review

**Q. Describe IREC's recommendation for the Supplemental Review process.**

A. In addition to the recommendations explained in the testimony of Sara Baldwin Auck, IREC recommends that the Commission adopt a Supplemental Review process that includes defined screens, instead of the current undefined process. IREC supports and recommends a Supplemental Review process with three screens: (1) 100% minimum load screen, (2) voltage and power quality screen, and (3) safety and reliability screen. This proposed revision is reflected in the redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2.**

Under this framework, if the aggregate DER rating exceeds 100% of minimum load, the project would go on to full study. However, if the project passes the 100% of minimum load screen or if this data is not available, the remaining two screens determine whether further study is required. The review of minimum load should follow a similar procedure to Screen 3.2.1.2 in terms of selecting relevant line sections.

The "Voltage and Power Quality Screen" identifies the key technical standards for voltage regulation and requires compliance with those standards to proceed under Supplemental Review. The screen would verify whether or not voltage is maintained within steady state limitations (i.e., in accordance with ANSI C84.1), and evaluate compliance with flicker, rapid voltage change, and harmonics standards.

The "Safety and Reliability Screen" gives utilities flexibility in identifying a full range of possible technical considerations. It identifies typical considerations that might be relevant to help applicants better understand the review process, but does not require that they be applied in every circumstance. It also allows the utility the discretion to identify "other factors" in evaluating safety and reliability impacts. These other factors notably include unique loading characteristics that could increase DER impacts on the system, whether or not the DER is electrically close to the substation, certification of the DER equipment, and evaluation of operational flexibility constraints.

**Q. Why does IREC recommend use of defined screens in the Supplemental Review process?**

A. The current Supplemental Review process does not define how the utility will determine if a project could be interconnected safely and reliably. This prevents customers from knowing how Supplemental Review will be applied and from having the information they need to decide whether to go through Supplemental Review or to go straight to the full study process. Defining the screens obligates a utility to efficiently review and identify the technical issues that warrant further study when a project is otherwise below 100% of minimum load.

In their comments in this proceeding, the utilities opposed adoption of these screens because they were concerned about having enough flexibility to process projects efficiently. They did not explain why they thought the defined screens would impact efficiency. In reality, the defined screens are likely to enhance efficiency because customers would have a clearer sense of what to expect from the Supplemental Review process, and could thus assess early on whether their project would likely pass the screens.

Defined screens would also establish a framework for the utilities to provide feedback to customers on the results of the analysis done during Supplemental Review. A process with defined screens would obligate the utilities to provide specific identification of what technical issues warrant further study when projects do not pass the Supplemental Review screens. At minimum, IREC recommends that the Commission require the utilities to provide a detailed technical report to the customer, which explains the analyses the utility conducted during Supplemental Review, and the outcomes. Since the customer is paying for the review and undergoing the additional time for the process, he should be able to expect an understanding of the analysis conducted by the utility.

**Q. How does Duke currently apply Supplemental Review?**

A. According to its responses to IREC's data requests, attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-8,** Duke currently applies the following screens, at its discretion, to a project undergoing Supplemental Review:

- Additional circuit analyses that take into account the fault contribution of the generating facility to the distribution system;
- For generating facilities co-located with load, review of the service transformer protective device to determine if the fault contribution from the generating facility has the possibility of operating the device;

- Additional circuit analyses to evaluate whether the generating facility would violate voltage and/or thermal overload limitations, including but not limited to:
  - daytime valley loading data modeling to determine whether the generating facility in aggregation with other queued- or connected-ahead facilities will cause any voltage regulators to experience reverse power flow;
  - ensuring addition of the generating facility will not cause deviation from Rapid Voltage Change and Flicker Study Criteria limitations;
  - ensuring addition of the generating facility will not cause voltages outside of the limitations set by ANSI C84.1; and
  - ensuring that the capacities of the generating facility, in aggregation with other queued- or connected-ahead facilities, will not exceed 10% of the substation transformer top-end rating (DEP) or 10% of the low-end/nominal rating (DEC);
- Measure of voltage rise and power backflow during valley loading conditions;
- Screen for service transformer protection, delivery side flicker, and winding configurations;
- Measure of voltage and flicker limits across the distribution system in relation to transformer inrush (utility-scale generators only); and
- Protection review to ensure device coordination and set points of all upstream protective equipment (utility-scale generators only).

**Q. How do the defined Supplemental Review screens from FERC SGIP that IREC proposes here compare to the screens that Duke currently applies in supplemental review?**

A. About five of the eight supplemental review screens currently used by Duke can be traced to similar screens in IREC's proposed Voltage and Power Quality screens. Protection evaluations could be considered a part of the Safety and Reliability screen. Loading screens, particularly Duke's screen based on 10%

of the substation transformer rating, would be better served by adopting IREC's proposed minimum load screen because the impacts of aggregate DER depend greatly on their relationship to load. While a percentage of substation transformer rating could possibly attempt to describe this relationship to load, using actual data on load (as done in IREC's proposed screen) would give a more accurate representation of whether or not significant impacts are likely for that specific circuit. Due to its inflexibility, a screen such as Duke's 10% of substation transformer rating screen is rendered essentially arbitrary. A higher level of detail and data is more appropriate for the Supplemental Review process.

**Q. Would adoption of the defined Supplemental Review screens prevent Duke from applying any of the Supplemental Review screens it currently applies?**

A. No.

**Q. What other jurisdictions have adopted these defined Supplemental Review screens?**

A. This procedure has been adopted by FERC, Ohio, Iowa, Illinois, California, Minnesota, New York, and Massachusetts.

## V. Technical Working Groups

**Q. Please describe IREC's recommendations regarding a technical working group.**

A. IREC recommends that such a Commission convene an Interconnection Technical Working Group. The group should include representatives from all stakeholders, including the utilities, DER developers, and outside interconnection experts. The purpose of the group would be to review any new issues or proposed changes to the interconnection process and requirements that might arise between major revisions of the Procedures.

IREC recommends that the working group be subject to Commission oversight, and have clear processes in place for how to review and approve new technical requirements. The Commission should lay out clear direction for the establishment of the Technical Working Group, including requiring that no changes should be able to go into effect unless there is consensus within the group on the changes, or the Commission has approved the changes. Further, the Commission should require that the Group's meetings be publicly noticed and its agenda and meeting minutes be filed in a docket or otherwise publicly posted. IREC recommends the Group meet quarterly.

**Q. Why does IREC recommend that the Commission convene a technical working group?**

A. The Technical Working Group is intended to provide for a collaborative process that can address technical interconnection issues as they arise. Because interconnection of DER is an evolving issue, it is important to have a group convened that can nimbly address and vet changes to how to interconnections are handled in a transparent and timely manner. The Technical Working Group in particular serves as a forum to resolve disagreement on technical issues. Technical experts can, and often do, disagree on issues, and other DER stakeholders can provide valuable information or experiences that will inform, and perhaps resolve, those disagreements. A Technical Working Group that involves diverse parties addressing issues in this way can thus facilitate development of standards that may be more workable and cost-effective, while still ensuring safety and reliability.

For example, North Carolina recently experienced Duke unilaterally implementing significant changes to how it evaluated interconnection applications, such as the creation of Line Voltage Regulator and Circuit Stiffness Ratio "screens" to interconnection. Developers reported that these actions seriously impacted projects already in the queue. When interconnection customers have already invested significantly in established utility processes, such unilateral changes to technical requirements without sufficient notification and a process for review and input is problematic and unfair. A Technical Working Group governed by a clear process will help avoid the adoption of abrupt and disruptive technical requirements, and instead ensure that all technical requirements proposed by the utilities are necessary and reasonable, while still allowing utilities to adapt to changing circumstances.

Also, the Technical Working Group will be well-positioned to address the revised IEEE 1547 and assist the Commission in adopting the standards. This is important, because the IEEE update and smart inverters will address many issues that have arisen in interconnections in North Carolina. Similarly, the Technical Working Group can grapple with evolving issues regarding energy storage and other emerging technologies, to ensure these new technologies are appropriately integrated into interconnections in North Carolina.

**Q. What other jurisdictions have similar technical working groups?**

A. Massachusetts and New York have standing technical working groups. California used to have a technical working group, but now has an interconnection discussion forum, which is an informal venue organized by the Commission for utilities, developers, and other stakeholders to explore issues related to interconnection. California also convenes technical working groups for specific issues, like addressing use of smart inverters.

**Q. Have you ever participated in a technical working group?**

A. Yes.

**Q. Please describe your experiences participating in technical working groups.**

A. The most notable technical working groups I have participated in are California's Smart Inverter Working Group ("SIWG"), Hawaiian Electric's Advanced Inverter Technical .Working Group ("AITWG"), Minnesota's Distributed Generation Working Group ("DGWG") Technical Subgroup, and Massachusetts' Technical Standards Review Group ("TSRG") Energy Storage Subgroup. The structure and focus of each group has been tailored to the state's specific needs.

California's SWIG started meeting in 2013, led by a hired facilitator and directed by the California Energy Commission. The goal was to submit recommendations to the California Public Utilities Commission ("CPUC") on incorporating advanced inverter requirements in the IOUs' interconnection rule

(Rule 21). After submitting three reports on three phases of necessary updates, the group continued to work on implementation of the rules and successfully implemented Phase 1 autonomous inverter requirements (ride-through, power factor, volt-var, and ramp rates) starting for interconnections in September 2017. The group continues to meet, convened by the CPUC, to implement Phase 2 and 3, as well as to advise on more technical issues arising in the current interconnection proceeding.

Hawaiian Electric's (HECO, MECO, HELCO) AITWG coalesced around the IOUs and stakeholders that had already begun to meet organically to tackle ride-through implementation and overvoltage testing. These issues had been identified as important requirements arising quickly due to the high inverter-based DER penetration they were experiencing. The group involved IOUs, inverter manufacturers, other industry and experts as well as local stakeholders. After quickly implementing ride-through and overvoltage testing, the group began working on updating the Hawaii IOUs' interconnection rule (Rule 14) with advanced inverter requirements similar to California's, as directed by the Hawaii PUC. These mostly consensus requirements were submitted to the Hawaii PUC in a matter of months. The group also crafted "inadvertent export" requirements for inverter-based non-export ("Self Supply") systems. After the PUC ended the net-metering program, the AITWG crafted self-certification requirements for equipment providers for Self Supply systems. The group continued efforts on certification by creating a "Source Requirements Document" for UL 1741 SA testing. In addition, the group gave input to research projects regarding advanced inverters that Hawaiian Electric was conducting with the National Renewable Energy Laboratory ("NREL"), which have resulted in some of the first US-based research publications on utility implementation of advanced inverter functions and their effects on customers and the distribution system.

Minnesota's DGWG was convened by the Minnesota PUC to draft state-wide interconnection procedures and technical requirements which had not yet existed. The technical subgroup has met since Spring 2018 to create the state's first standardized technical requirements based on the new IEEE 1547-2018 standard and incorporating DER grid support functionality. Over eight working group meetings, the group discussed the detailed elements of IEEE 1547 and other necessary requirements (such as inadvertent export and energy storage) while attempting to gain consensus on the numerous issues. IOUs and stakeholders have drafted a document with general requirements for all interconnections, which will likely include default settings for ride-through, tripping, and voltage regulation. The group continues to meet to refine the document before submitting it to the PUC for any necessary reconciliation and approval.

Massachusetts' TSRG Energy Storage Subgroup was set up to explore the various issues surrounding energy storage interconnection. It reports back to the main TSRG which meets quarterly and addresses interconnection issues in general as they arise. Thus far, the Energy Storage Subgroup has worked to identify relevant information for the interconnecting customer to provide so that the utility can efficiently interconnect energy storage systems. As this technology is increasing in adoption and hasn't been widely utilized before, both customer and utility are charting the course of interconnection. Standardizing information collection amongst utilities, even while state or national standards are yet to fully define the requirements, can increase the efficiency of the interconnection process. The TSRG also recently had a hand in implementing ride-through requirements that were requested by ISO New England to improve bulk-system reliability. Through consultation with the utilities, industry, and other experts, the new requirements were rolled out in a matter of months without major disruption. By convening a standing working group, the TSRG can react more quickly to the changing interconnection landscape as needs arise.

## <u>VI. Energy Storage</u>

**Q. Why should interconnection procedures account for interconnection of energy storage?**

A. Interest in energy storage is increasing, and more projects are being proposed with an energy storage component. Thus, interconnection procedures should provide clear rules regarding interconnection of energy storage to avoid confusion around the requirements, as well as unnecessarily costly and lengthy review processes.

**Q. How can the NCIP account for interconnection of energy storage?**

A. One way that this can be done is by evaluating an interconnection request on the basis of the manner in which the proposed DER is designed to actually perform rather than assuming that devices act differently than they were designed.

When an applicant seeks to interconnect multiple small generator facilities at a single site (such as a solar plus storage system), North Carolina's interconnection procedures currently require evaluation of the request on the basis of the facilities' aggregate nameplate capacity. That is, the request is evaluated as if the facilities together will feed the maximum amount of generation indicated on their nameplates onto the grid all at once, even if they are controlled in such a way that this would never happen.

This ignores the actual operational characteristics of interconnected generating facilities, especially systems that combine generation with energy storage devices. For example, when solar and storage are combined, the system may export far less energy than suggested by the aggregate nameplate capacity, and system controls can actually prevent the system from ever exporting the amount represented by the combined facilities' aggregate nameplate capacity. As a result, the aggregate nameplate capacity represents a scenario that assumes the devices are not functioning in the manner in which they are designed to perform.

Instead of this approach, systems should be evaluated based on their actual performance characteristics—that is, the amount of energy that they will actually be expected to export, based on system controls. Verification of these controls can involve testing, certification or other evaluations.

**Q. Did the stakeholder group reach any agreement on the issue of evaluating systems as they are actually used, not based on nameplate capacity?**

A. Yes. The working group reached a general consensus on improved language for NCIP Section 6.10.2 that would allow a more limited generating capacity to be studied if the applicant can show that appropriate controls are in place subject to mutual agreement. This language is reflected in the redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2**.

**Q. Does IREC have any concerns with the general consensus language for the revised Section 6.10.2.**

A. IREC has one concern. The revision includes language that limiting the generating facility's output must be done "through the use of a control system, power relay(s), or other similar device settings or adjustments as mutually agreed upon by the Utility and interconnection customer." This language is not intrinsically problematic, but in light of some comments by the utilities during the working group process, IREC has concerns with the "mutually agreed upon" language.

Specifically, during the working group process, the utilities expressed some opposition to allowing software-based controls. If use of export-limiting devices is subject to agreement by the utility, and the utilities do not allow software-based controls, this would effectively limit facilities to physical control devices, which is unnecessarily restrictive in light of modern smart inverter technology.

In this case, the Commission should either specify in its order that software controls must be allowed if they can be shown to have been tested using a protocol adequately designed to demonstrate limited export capabilities. Or, if a Technical

Working Group is convened, the Commission should require the Technical Working Group to determine what sorts of control devices may be allowed.

**Q. Why should the proposed Section 6.10.2 allow use of software-based controls?**

A. Software-based controls—specifically those involving "smart" inverters—are capable of controlling a project's export and provide other useful grid services, such as peak-shaving, demand reduction, and frequency regulation, among others. The inverters and control systems can be tested to verify their capabilities to control export, and there are processes underway by Underwriters Laboratories ("UL") to define these test standards. A Certification Requirement Decision is drafted and expected to be released by UL in the near future, allowing different equipment manufacturers to test to the same set of procedures to demonstrate compliance with inadvertent export rules. Allowing only physical controls would ignore an evolving technical reality and set North Carolina behind the curve in its efforts to ensure efficient, safe, and reliable DER interconnection.

## VII. Smart Inverters

**Q. How does IREC recommend that the Commission take into account IEEE 1547 and 1547.1 during this revision of the NCIP?**

A. This year, IEEE published the updated interconnection standard 1547-2018. The updates to the standard include voltage and frequency ride-through (for both bulk system reliability and distribution effects for high penetration), voltage regulation capabilities, standardized communications/control capabilities, and updated power quality requirements, among other improvements. The related testing standard, IEEE 1547.1, is expected to be published in late 2019 or early 2020, with UL 1741 adopting the new requirements soon thereafter. Certified inverters and other equipment could then be available on the market about 18 months later.

Adopting these standards in North Carolina will allow smart inverters and other DER to offer meaningful grid services that can help mitigate the impacts of increased DER growth. The standards will allow states and utilities to implement voltage regulation so high penetration effects can be mitigated. Along with ride-through capabilities for bulk-system reliability improvements, wide application of the standard should help increase hosting capacity of DER and reduce negative effects on the distribution system or other customers. This can only be accomplished if the standard is adopted and utilized.

It will take time and effort to adopt these new standards. Since there is no one default requirement in IEEE 1547-2018, interconnecting customers will need clear direction on what requirements their project will need to meet. The Commission should thus set forth a clear path for their rollout. The discussions about this process should begin immediately so that North Carolina can begin to take advantage of smart inverter capabilities once the testing standard is complete. The Technical Working Group that IREC has proposed and that I discuss above in my testimony would be an appropriate forum for this discussion.

## VIII. Interconnecting Non-Certified Devices

**Q. Describe Dominion's recommendation to limit interconnection only to certified devices.**

A. Dominion suggested during the working group process that the NCIP should allow only certified devices to be interconnected.

**Q. Does IREC support Dominion's proposal to limit interconnection only to certified devices?**

A. No.

**Q. Why does IREC oppose Dominion's proposal to limit interconnection only to certified devices?**

A. IREC's position is that all DER should have a path to interconnection, not just certified devices. This is the norm nationwide. Such devices can be safely and reliably interconnected after review during the full study process. The new IEEE 1547-2018 notes that equipment may not be fully certified, but lays out a pathway for evaluation and commissioning by the utility which can ensure a safe and reliable interconnection. From IEEE 1547-2018:

> Supplemental DER devices other than DER units may be used to achieve compliance with the requirements of this standard at the applicable reference point per Clause 4. These devices are not required to be co-located with the DER units, but shall be within the Local EPS. The requirements of this standard shall be met regardless of the location of the DER and supplemental DER devices within the Local EPS.[6]

Further, with the proliferation of new DER technologies, it is important to provide a way for projects to incorporate these new technologies that may not have been certified yet. To require all devices be certified would unnecessarily

[6] A local electric power system ("EPS") is an EPS contained entirely within a single premises or group of premises – i.e., that which is behind a single point of common coupling.

constrain developers and utilities from interconnecting safe and reliable equipment that is the best choice for the facility. For example, generators that do not meet all IEEE 1547 requirements could potentially utilize external relays for tripping protection, and anti-islanding requirements can be met with equipment that is not integrated with the DER out of the factory.

Also, synchronous generators, like those used by animal waste power projects, are generally not certified. If North Carolina wants to encourage development of animal waste power projects, it should not block interconnection of the equipment upon which these facilities will rely.

## IX. Conclusions

**Q. Please summarize your conclusions and recommendations.**

A. First, I conclude that Duke has been applying Fast Track Screen 3.2.1.2 too narrowly, which has resulted in nearly all eligible projects failing Fast Track review. To remedy this problem, the Commission should revise the NCIP to clarify how a "line section" should be determined. Also, the Commission and the parties should consider revising Screen 3.2.1.7, in light of Duke's current practices of loading protective devices up to 100% of their ratings.

Second, the Fast Track eligibility limit for lines under 5 kV should be raised from 100 kW to 500 kW.

Third, the Commission should adopt defined Supplemental Review screens, which are flexible and can accommodate Duke's current Supplemental Review screening process.

Fourth, the Commission should create an interconnection technical working group to address any technical issues that arise in implementing the standards.

Fifth, the NCIP should be revised to accommodate interconnection of energy storage by ensuring that projects are studied as they actually operate.

Sixth, the Commission should establish a process for adoption of IEEE 1547-2018.

Seventh, the Commission should not approve any revisions to the NCIP that would foreclose a path to interconnection for non-certified devices.

**Q. Does this conclude your testimony?**

A. Yes.

CHAIRMAN FINLEY: And his rebuttal testimony of January 8, 2019 of 22 pages and one exhibit are introduced into evidence at this time.

MS. BEATON: Thank you, Mr. Chairman.

(Whereupon, the prefiled rebuttal testimony of Brian M. Lydic was copied into the record as if given orally from the stand.)

(Whereupon, Exhibit BL-Rebuttal-1 was identified as prefiled and admitted into evidence.)

## I. Introduction

**Q. Please state your name, title, employment, and business address.**

A. My name is Brian M. Lydic. I am employed by the Interstate Renewable Energy Council, Inc. ("IREC") as a Regulatory Engineer. IREC's business address is P.O. Box 1156, Latham, NY 12110-1156. IREC operates as a virtual organization with employees in numerous states. I reside and work remotely in Ann Arbor, Michigan.

**Q. Are you the same Brian M. Lydic who submitted direct testimony in this proceeding?**

A. Yes.

**Q. For whom are you testifying?**

A. I am testifying on behalf of the Interstate Renewable Energy Council, Inc. ("IREC").

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my testimony is to respond to other parties' direct testimony in this proceeding. I do not respond to every point made by every witness in this proceeding. Instead, my testimony focuses on those points where I disagree with other witnesses on technical points, or where I believe another witness has misunderstood IREC's proposals or positions.

**Q. Please summarize the key points of your rebuttal testimony.**

A. The key points of my rebuttal testimony are:

- I explain that IREC's proposed clarification of Screen 3.2.1.2 would not create a risk of impacts to the utilities' systems going unnoticed and instead ensures the Fast Track process operates as intended.
- I explain that Screen 3.2.1.4 should not be eliminated because Fast Track is not limited to only inverter-based generators.
- I explain that raising the Fast Track eligibility limit does not increase the risk of system impacts because the Fast Track screens would send any projects that have a risk of impacts to further study.
- I explain that IREC's defined supplemental review proposal is flexible and would accommodate the utilities' current practices, while providing greater transparency to customers.
- I explain why Duke's Technical Standards Review Group is a step in the right direction, but that the Commission should outline rules that ensure Commission oversight and broad stakeholder participation.

## II. Fast Track Screens

**Q. Please reintroduce IREC's position with regard to Fast Track Screen 3.2.1.2.**

A. As I explained in my direct testimony, Screen 3.2.1.2 is also known as the "15% of peak load screen," which sets a "low penetration level" to identify when higher penetration effects need not be accounted for or studied. The screen is based on the principle that negative grid impacts from an generating facility are unlikely if the amount of distributed generation ("DG") on a feeder is significantly smaller than feeder capacity and always less than feeder load.

During the stakeholder process for revisions of the North Carolina Interconnection Procedures ("NCIP"), I learned that Duke Energy Carolinas/Duke Energy Progress ("Duke") is applying this screen very narrowly by identifying a "line section" for the purpose of the screen by selecting the first upstream sectionalizing device, which is often a fuse at the distribution transformer near the proposed location of the DER seeking to interconnect. As I explained in my direct testimony, this approach does not serve to identify whether significant impacts could be created on the distribution circuit. This undermines the purpose of the Fast Track process and sends most small North Carolina projects to Supplemental Review unnecessarily.

Instead, it is my opinion that the appropriate approach is to generally use automatic sectionalizing (interrupting) devices, like line reclosers, as the points to break up the feeder into "line sections." In my direct testimony, I recommended that the first recloser upstream of the DER on the primary feeder be utilized as the relevant device. If no reclosers are upstream of a DER, then the substation circuit breaker would be utilized. Once the relevant device is selected, the aggregate DER and load located between that device and the end of the feeder would be analyzed for the 15% criterion. This remains my recommendation.

For these reasons, IREC recommends the following clarifying footnote be added to Screen 3.2.1.2, as set forth in the redline of the NCIP attached to the Direct Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2:**

> A. If the point of common coupling is downstream of a line recloser, include those medium voltage (MV) line sections from the recloser to the end of the feeder. If the 15% criterion is passed for aggregate distributed generation and peak load at first upstream recloser, then the screen is passed.
>
> B. If the point of common coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak load for the whole feeder, then the screen is passed.

IREC also recommends revising the definition of "line section" in Attachment 1, Glossary of Terms, as set forth in the redline of the NCIP attached to the Rebuttal Testimony of Sara Baldwin Auck as **Exhibit SBA-Rebuttal-1:**

> **Line section** – A portion of a distribution circuit bounded by an automatic sectionalizing device and the end of the feeder. When applying this to the 15% of peak load screen described in Section 3.2.1.2 or the 100% of minimum load screen as described in Section 3.4.3.1, the smallest line section to be evaluated should begin at the first line recloser or circuit breaker upstream of the Point of Interconnection.

This will ensure that the Fast Track process serves its purpose of efficient review of projects that will not cause significant grid impacts

**Q. Have any parties opposed IREC's proposal?**

A. Yes.

**Q. Describe the other parties' explanations of why IREC's proposal to add the clarifying footnote to Screen 3.2.1.2 and revise the definition of "line section" should not be adopted.**

A. Duke's Witness Gajda explains that Duke does not support the proposal because the 15% of peak load screen "is a valuable 'flagging step' in identifying the potential for uncontrolled high voltage occurrences."[1] Witness Gajda states that this "flagging step" is important because customer-sited generation in North Carolina is primarily net-metered, and the increase in rooftop solar brings an increased risk of uncontrolled high voltage.[2]

Dominion Energy North Carolina's ("Dominion") Witness Michael J. Nester states that IREC's proposal "would risk the loss of visibility to technical issues closer to the customer's premises," but provides no further explanation.[3]

Public Staff's Witness Tommy C. Williamson, Jr. states that the screen should not be changed "on the sole premise of allowing more projects to pass the screen."[4]

**Q. Do you agree with the other parties' explanation of why IREC's proposal to add the clarifying footnote to Screen 3.2.1.2 and revise the definition of "line section" should not be adopted?**

A. No.

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[1] Direct Testimony of John W. Gajda on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Gajda Testimony"), at 26:14-18.

[2] *Id.* at 26:8-14.

[3] Direct Testimony of Michael J. Nester on behalf of Dominion Energy North Carolina ("Nester Testimony"), at 9:16-20.

[4] Direct Testimony of Tommy C. Williamson, Jr. on behalf of Public Staff – North Carolina Utilities Commission ("Williamson Testimony"), at 12:15-16.

**Q. Why do you disagree with the other parties' explanation of why IREC's proposal to add the clarifying footnote to Screen 3.2.1.2 and revise the definition of "line section" should not be adopted?**

A. First, Dominion's Witness Nester provides no explanation of why IREC's proposal would be problematic, instead simply concluding that it would be. Witness Nester does not explain *why* IREC's proposal would "risk the loss of visibility to technical issues closer to the customer's premises." Indeed, as I explained in my direct testimony and as I explain further below, Screen 3.2.1.9 already provides visibility to issues closer to the premises for single-phase secondaries.

I understand that Witness Gajda is concerned about being able to rely on Screen 3.2.1.2 (the 15% of peak load screen) to identify the potential for uncontrolled high voltage occurrences.[5] But he does not explain *why* IREC's proposed clarification would undermine the ability to identify secondary voltage rise, especially in light of other screens that would catch this, as I explain below.

This lack of explanation makes it challenging to respond to Duke's position. Also, Duke's witnesses do not provide evidence to explain why Duke's application of Screen 3.2.1.2—in a manner that appears to be different than other jurisdictions I am familiar with and for a purpose the screen was not developed for—is reasonable. Since the 15% screen is not meant to identify secondary voltage rise, the 15% metric is likely not appropriate to screen for uncontrolled

[5] Gajda Testimony at 26:3-18.

high voltage. Screen 3.2.1.9 utilizes the 65% of transformer nameplate rating metric for the purpose of screening for uncontrolled high voltage, and this number would likely, and rightly, allow for much more aggregate DER behind a transformer than the 15% screen would when applied as Duke does.

First, North Carolina is no different than other states in the nation where customer-sited residential and commercial rooftop solar is primarily net-metered. Net-metered systems still export power quite regularly, and voltage rise is certainly an issue that deserves investigation when warranted. Indeed many states have significantly more net-metered systems than North Carolina.[6] However, states that have very large penetrations of net-metered systems on shared secondaries and that use the SGIP-based screens do not flag secondary voltage issues via the 15% of peak load screen, like Duke appears to be doing. That issue is addressed by another screen.

Specifically, Witness Gajda focuses on using Screen 3.2.1.2 to "identify[] the potential for uncontrolled high voltage occurrences."[7] However, the purpose of this screen is not to identify secondary voltage rise. As I explained in my direct testimony, the 15% of peak load screen was developed to set a general low penetration level where effects that would come with higher penetration—including unintentional islanding, voltage aberrations, protection miscoordination,

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[6] *See* Energy Information Administration, Form EIA-861M (formerly EIA-826) detailed data, available at: https://www.eia.gov/electricity/data/eia861m/

[7] Gajda Testimony at 26:15-16.

and other potentially negative impacts—are unlikely.[8] In short, its purpose is to evaluate larger-scale issues caused by backwards power flow through the distribution system on medium voltage (MV) lines.[9]

It is not intended to address other, more specific safety and reliability concerns, as Duke appears to be misapplying it to screen for secondary voltage rise. As I explained in my direct testimony, that is the job of Screen 3.2.1.9, which is designed to address localized issues on single-phase low voltage shared secondaries, including high voltage occurrences when DER (including rooftop solar) is exporting.[10]

**Q: In your opinion, is Duke's current application of Screen 3.2.1.2 as described in Witness Gajda's direct testimony, page 26, Good Utility Practice?**

A: No. In my opinion, Duke's application of this screen is not justified. Duke applies the 15% of peak load screen in a manner that undermines the efficiency of Fast Track with little to no enhancement to safety and reliability. Indeed, the high voltage occurrence issue that Duke says it uses the screen to address is already addressed directly, and more appropriately, by Screen 3.2.1.9 for single-phase secondaries. If a real concern exists with high voltage on three-phase shared secondaries, then a new screen tailored to that purpose should be proposed, rather

[8] Direct Testimony of Brian M. Lydic on behalf of IREC ("Lydic Testimony") at 5:18 - 6:2.

[9] *Id.* at 10:12-14.

[10] *Id.* at 10:9-12.

than misapplying a screen in a way that would not effectively screen for that scenario and has the added consequence of forcing the vast majority of projects into further study unnecessarily.

**Q. Do you agree with Public Staff Witness Williamson's assertion that IREC's proposal is based on the "sole premise of allowing more projects to pass the screen"?[11]**

A. No. IREC is not proposing that Screen 3.2.1.2 be arbitrarily adjusted to allow more projects to pass the screen for passage's sake. IREC is proposing that the screen be used for its intended purpose, rather than using it in an unintended way that assures many projects will fail the screen, while doing little to identify the risk of actual impacts from the proposed project. To be effective in efficiently processing projects in the queue, a screen should be used in a way such that it predicts with at least a modicum of accuracy whether or not a DER system would cause issues that need further study and alteration or upgrades. Utilizing a screen in such a way that most projects are likely to fail regardless of whether or not they likely present any issues that need further study only wastes the utility's and the customer's time.

The cumulative effect of multiple systems is exactly what Screen 3.2.1.2 is meant to flag, rather than the effect of a single system. Using the screen in the manner Duke suggests would be akin to designing an exit survey and then polling only a single person and making assumptions about the outcome of the election

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[11] Williamson Testimony at 12:15-16.

based on that one person's answers. As demonstrated by examples given by Duke (*see* **Exhibits BL-Direct 3 & BL-Direct-4**), a single PV system causes screen failure. This is unsurprising, since the screen is evaluated so close to the point of interconnection. One of the examples of the failed screen noted that there were no existing projects on the feeder. While, when applied as does Duke, this screen failure does flag the fact that the PV system is "somewhat large" compared to the transformer load, it gives no clues as to whether the wider distribution system will see any effects from aggregated generation or not (which is what the screen should flag). It is often the case that net-metered PV systems are sized "somewhat large" compared the transformer load without causing voltage problems (*e.g.*, a ~30kVA PV system on a 75kVA transformer bank as used in Duke's Response to Public Staff Data Request 4-8, available as **Exhibit BL-Direct-3**). Therefore, Screen 3.2.1.2 is a poor screen for such considerations. If the utility believes that a screen in addition to Screen 3.2.1.9 is required to flag secondary voltage issues (e.g., for three-phase shared secondaries), then a new screen should be proposed that would do so, rather than repurposing an existing screen to attempt to fit that need.

While we are not aware of written explanations that document how other utilities apply the 15% of peak load screen, we know that projects across the country are passing this screen. The Solar Energy Industries Association conducted a survey of its members in December of 2018 to inquire into how often projects in other top solar states were failing the 15% of peak load screen. The results show that not a single company reported that their projects fail "almost every single time" like is seen in North and South Carolina for projects between 20-100 kW. Indeed, over 66% percent of the respondents indicated that their projects "almost never" fail the 15% of peak load screen in that size range. The full survey results can be found attached as **Exhibit BL-Rebuttal-1.** If other utilities applied the same interpretation to the screen as Duke does then one would expect to see this screen failed in a very high percentage of cases all over the country, which is simply not occurring.

IREC does not propose to change the screen for the sake of enabling projects to pass at the expense of safety and reliability. Rather we propose a change to appropriately screen for risks while helping to create and fair and efficient interconnection process for the state.

## III. Fast Track Eligibility

**Q. Please reintroduce IREC's position with regard to Fast Track eligibility limits.**

A. IREC recommends that the size limit for Fast Track eligibility on lines with a voltage of < 5 kV, regardless of location, be raised to accommodate projects of up to 500 kW. This proposed revision is reflected in IREC's proposed redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2.** IREC makes this recommendation because the current limit of 100 kW is overly conservative, and may unnecessarily send relatively small projects, mostly net energy metering ("NEM") projects, to full study.

**Q. Have any parties opposed IREC's proposal?**

A. Yes.

**Q. Describe the other parties' explanations of why IREC's proposal to raise the Fast Track eligibility limit for projects connecting to lines with a voltage of < 5kV.**

A. Duke Witness Gajda explains that Duke opposes raising the Fast Track eligibility limit for projects connecting to <5 kV lines because of the "potential risk for system impacts" posed by projects larger than 100 kW.[12]

Dominion's Witness Nester explains that <5 kV lines are older, and require care to ensure safe and reliable interconnections.[13]

Public Staff's Witness Williamson asserts that a lower Fast Track eligibility limit does not "hinder a proposed Generating Facility's ability to move through the interconnection process" and that it is "prudent to require additional study of a 500kW facility."[14]

**Q. Do you agree with the other parties' explanation of why IREC's proposal raise the Fast Track eligibility limit for projects connecting to lines with a voltage of < 5kV should not be adopted?**

A. No.

**Q. Why do you disagree with the other parties' explanation of why IREC's proposal raise the Fast Track eligibility limit for projects connecting to lines with a voltage of < 5kV should not be adopted?**

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[12] Gajda Testimony at 25:5-7.

[13] Nester Testimony at 9:10-13.

[14] Williamson Testimony at 10:6-9.

A. There is no risk from allowing projects up to 500 kW proposing to interconnection to 5 kV lines to simply be *eligible* for Fast Track review. The Fast Track screens will catch any projects that require full study, so there is no additional safety and reliability risk from raising the eligibility threshold. None of the parties' witnesses provide any technical explanation of why it would be impossible—or even unlikely—for a project of 500 kW or below to pass Fast Track, and the point of Fast Track is to allow as many projects as possible to avoid undergoing full study unnecessarily.

In contrast, I explained in my direct testimony that a project above 100 kW and below 500 kW proposing to connect to a < 5 kV line could pass the Fast Track screens. As I explained, even with a maximum load of 480A at 4.16kV, a 500 kW DER with maximum output of 69A could pass the 15% of peak load criteria of Screen 3.2.1.2. The point is to require full study only for projects that actually need it—that is, projects that could have safety and reliability impacts. Because 100 - 500 kW projects could be interconnected safely and reliably without full study, the Fast Track eligibility limit should be raised.

Finally, I want to emphasize that Witness Williamson's statement that keeping the eligibility limit at 100 kW will not hinder a project's ability to move through the interconnection process is wrong. While projects undergoing Fast Track review may receive an Interconnection Application in a matter of weeks, going to full study can mean a wait of years for a project. To force projects that could be interconnected without full study to nonetheless go through that onerous process is an unnecessary hindrance. Again: if the project needs full study, the Fast Track screen will catch that, and a study will happen. IREC's proposal in no way avoids full study where it is actually warranted.

## IV. Supplemental Review

**Q. Please reintroduce IREC's position with regard to the Supplemental Review process.**

A. IREC recommends that the Commission adopt a Supplemental Review process that includes defined screens: (1) 100% minimum load screen, (2) voltage and power quality screen, and (3) safety and reliability screen. This proposed revision is reflected in the redline of the NCIP attached to the Testimony of Sara Baldwin Auck as **Exhibit SBA-Direct-2**. Under this framework, if the aggregate DER rating exceeds 100% of minimum load, the project would go on to full study under Section 4. However, if the project passes the 100% of minimum load screen or if this data is not available, the remaining two screens determine whether further study is required.

**Q. Have any parties opposed IREC's proposal?**

A. Yes.

**Q. Describe the other parties' explanations of why IREC's proposal to include defined screens in the Supplemental Review process should not be adopted.**

A. Duke's Witness Gajda's testimony seems to indicate that Duke opposes to adopting standardized Supplemental Review screens because it is concerned about limiting future flexibility.[15] Witness Gajda also explains that Duke opposes "'supplementing' the Fast Track 90% of substation and circuit minimum load screen with IREC's suggestion for a less stringent 100% of minimum load screen in Supplemental Review."[16] Witness Gajda asserts that the 100% of minimum load screen is not an appropriate Fast Track screen because load patterns shift on distribution circuits.[17]

Dominion's Witness Nester likewise appears to think that IREC is proposing to replace the Fast Track 90% of substation and circuit minimum load screen with the Supplemental Review 100% of minimum load screen.[18] He also expresses concern about load patterns shifting.[19] Finally, he notes that minimum load data may not always be available.[20]

**Q. Do you agree with the other parties' explanation of why IREC's proposal to include defined screens in the Supplemental Review process should not be adopted?**

A. No.

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[15] Gajda Testimony at 31:13-21.

[16] *Id.* at 32:6-8.

[17] *Id.* at 33:18-20.

[18] Nester Testimony at 10:5-9.

[19] *Id.* at 11:1-3.

[20] *Id.* at 10:17-21.

**Q. Why do you disagree with the other parties' explanation of why IREC's proposal to include defined screens in the Supplemental Review process should not be adopted?**

A. Witness Gajda misunderstands how a defined Supplemental Review process—as IREC proposes and as it exists in FERC SGIP and in many states—works. The process is actually quite flexible. As I explained in my direct testimony, Duke should generally be able to continue its current supplemental review approach under IREC's proposed framework.[21] Indeed, Witness Gajda recognizes that Duke's current approach fits within the framework proposed by IREC.[22]

The improvement with the more defined framework is that it promotes transparency. It would allow developers to better assess how their projects might fare in Supplemental Review. It also would provide a framework for the utilities to explain to their customers their screen results. IREC's proposal does not, as Witness Gajda asserts, require a study engineer to "specifically address and document" each criteria in the defined Supplemental Review Screens.[23] The screens are designed to provide a utility flexibility to apply the screens' criteria at its discretion; the definition serves to provide greater insight into what, exactly, Supplemental Review entails. In short, IREC's proposal is not over-prescription,

[21] Lydic Testimony at 22:10-13.

[22] Gajda Testimony at 34:7-9.

[23] *Id.* at 35:3-4.

as Witness Gajda argues; this is simply an enhancement of transparency and certainty that will benefit all parties.

**Q. Do Witness Gajda and Witness Nester understand the purpose of the 100% of minimum load screen in IREC's proposal and how it will be used?**

A. No. Duke Witness Gajda and Dominion Witness Nester appear to have misunderstood IREC's proposal. They mistakenly believe that the proposed *Supplemental Review* 100% of minimum load screen would replace the *Fast Track* 90% of substation and circuit minimum load screen (Screen 3.2.1.3). This is not true. IREC does not propose to change that Fast Track screen at this time, and the 100% of minimum load screen does not replace it.

The point of the 100% of minimum load screen is to provide a threshold for Supplemental Review. Under IREC's proposal, if a project undergoing Supplemental Review exceeds 100% of minimum load, it fails Supplemental Review and must go on to full study. However, if a project is below 100% of the line section's minimum load, the utility then goes on to review the project's impacts under the remaining two flexible Supplemental Review screens (Voltage and Power Quality Screen, and Safety and Reliability Screen), which allow the utility to determine whether the project can be interconnected without further review when penetration is high on the circuit. The proposed Voltage and Power Quality screen considers whether "the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions."

This should allow the utility to review any possible impacts that they are concerned about regarding voltage regulator type or programming.

Regarding Witness Gajda's and Witness Nester's concern about minimum load shifts, this was considered by the states that first adopted the defined supplemental review process and FERC had the opportunity to consider this issue as well.[24] Indeed, FERC expressly rejected Duke's argument:

> Regarding Duke Energy's assertion that the 15 Percent Screen should be maintained [instead of using the 100% of minimum load in Supplemental Review] because it includes a safety margin that minimizes the negative effects of intermittent generation (such as problems with smart grid applications, load monitoring equipment, restoration schemes, and voltage and reactive power control schemes), the Commission finds that such issues are appropriately addressed under the voltage and power quality and the safety and reliability screens of the supplemental review.[25]

The premise of the Supplemental Review process is that the utility first identifies if the aggregate generation is below 100% of minimum load. If not, the project must go to study. If it is, however, then the utility is able to evaluate whether, for example, there is a significant enough of a risk that load will disappear, and if so, whether further study is warranted when it applies the two other screens. The concern of changing load and other issues were considered by other states and FERC and is not a reason for using an undefined review process.

As for minimum load data not being available for some lines, IREC's proposal (which is also used by FERC and multiple other states) accounts for this.

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[24] FERC Order 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159, at 81-85 (Nov. 22, 2013).

[25] FERC Order 792 at 146.

In such cases, the utility would have the option of estimating the minimum load, or if that was not possible the utility would simply explain as much, then apply the remaining screens. My understanding is that this is similar to what Duke already does. Adding the 100% of minimum load screen would actually save Duke time: it would eliminate from further supplemental review projects that already exceed this threshold.

**Q. Do you have anything you would like to add to your testimony regarding the defined Supplemental Review process?**

A. Yes. If IREC's proposal for a defined and transparent Supplemental Review process is adopted, IREC's proposed definition of "Line section" should indicate that it applies both to the 15% of peak load Fast Track screen (Section 3.2.1.2) and the 100% of minimum load Supplemental Review screen (IREC's proposed Section 3.4.3.1). Accordingly, as shown below, the underlined text should be added:

> **Line section** – A portion of a distribution circuit bounded by an automatic sectionalizing device and the end of the feeder. When applying this to the 15% of peak load screen described in Section 3.2.1.2 <u>or the 100% of minimum load screen as described in Section 3.4.3.1</u>, the smallest line section to be evaluated should begin at the first line recloser or circuit breaker upstream of the Point of Interconnection.

This revised definition is incorporated into IREC's redline attached to the Rebuttal Testimony of Sara Baldwin Auck as **Exhibit SBA-Rebuttal-1.**

## V. Technical Working Groups

**Q. Please reintroduce IREC's position with regard to a technical working group.**

A. IREC recommends that the Commission convene an Interconnection Technical Working Group, made up of representatives from all stakeholders. The purpose of the group would be to review new issues that arise regarding implementation of the interconnection process. This group should be subject to Commission oversight and have clearly defined guidelines, including requiring publicly noticed, regular meetings.

**Q. Witness Gajda states that Duke will maintain open dialogue regarding Fast Track and Supplemental Review in its Technical Standards Review Group ("TSRG").[26] Has IREC ever been invited to, or notified of, a Duke TSRG meeting?**

A. No.

**Q. Do you have any clarifications you would like to make to IREC's proposal as explained in your direct testimony?**

A. Yes. In my direct testimony, page 23:6-9, I stated that the Commission should require that "no changes should be able to go into effect unless there is consensus within the group on the changes, or the Commission has approved the changes." To clarify, IREC proposes that the Technical Working Group strive for consensus. In cases where consensus is not achieved, there should be a process for members of the working group to seek the Commission's review of the matter. Commission review would not be required every time there is not consensus—only when a party appeals.

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[26] Gajda Testimony at 36:18-22.

**Q. Have any parties supported this IREC's proposal?**

A. Yes. NCSEA supports a similar proposal.

**Q. Have any parties opposed IREC's proposal?**

A. Yes.

**Q. Describe the other parties' explanations of why IREC's proposal to establish a technical working group with Commission oversight should not be adopted.**

A. Duke's Witness Gajda expresses concern that requiring consensus would not be workable and states that Duke's existing TSRG is sufficient.[27] Public Staff's Witness Williamson also thinks Duke's approach is sufficient.[28]

**Q. Do you agree with the other parties' explanation of why IREC's proposal to establish a technical working group with Commission oversight should not be adopted?**

A. No.

**Q. Why do you disagree with the other parties' explanation of why IREC's proposal to establish a technical working group with Commission oversight should not be adopted?**

A. While IREC appreciates that Duke has attempted greater transparency with its TSRG, it is not a replacement for a working group with Commission oversight. Commission oversight will ensure that the Group facilitates constructive

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[27] Gajda Testimony at 53-58.

[28] Williamson Testimony at 25-26.

conversation and that the utilities participate as parties to a conversation rather than dictating agendas and being in control of the exchange of information. Also, while we agree that utilities should have the ability to make final decisions on technical implementation of interconnection, some of the decisions Duke has made recently have fundamentally changed how a project might interconnect, because the technical "guidelines" actually serve as "screens" to interconnection. Such action warrants Commission oversight, and a process in the working group that provides a method for members to bring issues to the Commission's attention will address that issue.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

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MS. BEATON: And my second question is regarding examination of my witness on the Settlement Agreement, which yesterday you indicated we could ask, would you prefer I ask that during my direct examination or shall I save that for redirect?

CHAIRMAN FINLEY: Direct examination.

MS. BEATON: All right. Thank you. The Interstate Renewable Energy Council calls Sara Baldwin Auck to the stand.

SARA BALDWIN AUCK; Having been duly sworn, Testified as follows:

DIRECT EXAMINATION BY MS. BEATON:

Q Thank you, Ms. Auck. So I am behind you, and it is fine to continue to look forward at the Commission and speak into the microphone as I ask you these questions. Can you please state your name for the record.

A My name is Sara Baldwin Auck.

Q And can you please tell me your employer and your business address?

A Yes. I am employed by the Interstate Renewable Energy Council, or IREC. Our business mailing address is P.O. Box 1156, Latham, New York, 12110. I reside in Salt Lake City, Utah. IREC operates as a virtual organization, so we have folks all over the country.

Q Thank you. And what is your position with IREC?

A My position as of today is the Vice President of Regulatory, and I was recently promoted from Regulatory Director.

Q Thank you. And did -- Ms. Auck, did you cause to be -- did you cause direct testimony of approximately 58 pages with 10 exhibits which were labeled SBA-Direct-1 through SBA-Direct-10 to be prefiled in this docket?

A Yes, I did.

Q And do you have any changes or corrections to your prefiled direct testimony?

A No, I do not.

Q And so if I were to ask you the same -- if I were to ask you today the same questions as written in your prefiled direct testimony, would your answers be the same?

A Yes.

Q And were the exhibits to your direct testimony prepared by you or under your direction?

A Yes.

MS. BEATON: So Mr. Chairman, I would move to have Ms. Auck's prefiled direct testimony entered into the record as though given orally today from the stand, and to have the exhibits attached to her testimony also entered.

CHAIRMAN FINLEY: You're moving both the direct and rebuttal?

MS. BEATON: You want me to do them at the same time? Sorry about that.

CHAIRMAN FINLEY: Why don't you do that?

MS. BEATON: Okay. Great. I'll do that at the same time, then.

Q All right. Ms. Auck, did you also cause to be -- cause rebuttal testimony of approximately 32 pages with one exhibit labeled Exhibit SBA-Rebuttal-1 to be prefiled in this docket?

A Yes, I did.

Q And do you have any changes or corrections to your prefiled rebuttal testimony?

A No.

Q So if I were to ask you the same questions today from the stand, would your answers be the same?

A Yes.

Q And was the exhibit to your rebuttal testimony prepared by you or under your direction?

A Yes.

MS. BEATON: All right. Now Mr. Chairman, I would move to have both Ms. Auck's prefiled direct and rebuttal testimony and exhibits entered into the record as though given orally from the stand.

CHAIRMAN FINLEY: Ms. Auck's direct prefiled testimony of 58 pages of November 19, 2018 is copied into the record as though given orally from the stand. Her 10 direct exhibits are marked for identification as premarked in the filing.

(Whereupon, the prefiled direct testimony of Sara Baldwin Auck was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits SBA-Direct-1 through SBA-Direct-10 were identified as premarked.)

## I. Introduction

**Q. Please state your name, position, and business address for the record.**

A. My name is Sara Baldwin Auck. I am the Regulatory Program Director for the Interstate Renewable Energy Council, Inc. ("IREC"). IREC's business address is P.O. Box 1156, Latham, NY 12110-1156.

**Q. Please summarize your professional background and experience.**

A. My experience and qualifications are described in my curriculum vitae, which is **Exhibit SBA-Direct-1** to this testimony.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Interstate Renewable Energy Council, Inc. IREC is a non-partisan, non-profit organization working nationally to increase consumer access to sustainable energy and energy efficiency through independent fact-based policy leadership, quality workforce development, and consumer empowerment. In service of our mission, IREC works to increase the adoption of policies and regulatory reforms that expand access to and streamline grid integration of distributed energy resources ("DERs") to optimize their widespread benefits. IREC supports the creation of robust, competitive clean energy markets, though IREC does not have a financial stake in those markets.

The scope of our work includes:

1. Updating interconnection processes to facilitate deployment of distributed energy resources and remove constraints to their integration on the grid;
2. Developing and advancing regulatory policy innovations;
3. Generating and promoting national model rules, standards, and best practices;
4. Fostering collaborative partnerships with diverse stakeholders to build consensus and achieve workable solutions;
5. Incorporating distributed energy resource growth into utility distribution system planning and operations;
6. Expanding programs that facilitate consumers' ability to host a renewable energy system to directly self-supply energy needs or provide energy to the grid;

7. Implementing shared renewable energy programs to expand options for consumers that cannot host a renewable energy system;
8. Developing for clean energy educators and training programs, all of which work together to form a strong foundation for a highly-trained, quality-prepared workforce;
9. Developing quality and competency standards, accreditation and certification programs, for the renewable energy and energy efficiency workface.

**Q. Please describe IREC's involvement in the development of interconnection standards.**

A. IREC has recently been or is currently involved in interconnection proceedings in Illinois, Ohio, Minnesota, Iowa, South Carolina, Montana, Massachusetts, California, Maryland, Nevada, New York, and Hawaii. IREC participated in the initial proceeding at Federal Energy Regulatory Commission ("FERC") to adopt the Small Generator Interconnection Procedures ("SGIP") and was an active participant in the 2013 updates to those procedures. In addition, IREC has published Model Interconnection Procedures, which capture best practices with respect to interconnection.

In 2014, IREC petitioned the North Carolina Utilities Commission ("Commission") to revise North Carolina's Interconnection Procedures ("Procedures" or "NCIP") and participated actively in the working group and proceeding that followed. On May 15, 2015, the Commission approved revisions to Procedures and ordered Public Staff to convene a working group two years later to determine whether the Procedures should be revised or updated further. Public Staff did so in June 2017, and through December 2017, a stakeholder group ("2017 Working Group") considered revisions to the Procedures.

IREC participated in and made substantive contributions to the 2017 working group discussions. The group discussed a long list of revisions proposed by participants, and while there were a few revisions upon which there was general agreement, there is a long list of topics upon which consensus was not reached. Following the 2017 Working Group meetings, IREC filed detailed comments with the Commission in this docket on January 29, 2018, and March 12, 2018.

**Q. Have you testified previously before the North Carolina Utilities Commission?**

A. No. I previously provided written testimony to the California Public Utilities Commission. In my role as Regulatory Director, I oversee IREC's participation in a numerous proceedings before state utility commissions across the country. This includes managing IREC's participation in interconnection rulemaking before utility commissions in California, Illinois, Iowa, Maryland, Minnesota, Nevada, New York, North Carolina, South Carolina, and Utah.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

- **Exhibit SBA-Direct-1**: Curriculum Vitae of Sara Baldwin Auck
- **Exhibit SBA-Direct-2**: IREC's Proposed Redline to North Carolina's Interconnection Procedures
- **Exhibit SBA-Direct-3**: IREC's Proposed Public Interconnection Queue
- **Exhibit SBA-Direct-4**: IREC's Proposed Quarterly Reports
- **Exhibit SBA-Direct-5**: IREC's Proposed Hosting Capacity Map
- **Exhibit SBA-Direct-6**: *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources*
- **Exhibit SBA-Direct-7**: *Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators*
- **Exhibit SBA-Direct-8**: Duke's Response to IREC Data Request 1
- **Exhibit SBA-Direct-9**: Duke's Response to Public Staff Data Request 8
- **Exhibit SBA-Direct-10**: California Net Energy Metering Interconnection Costs

**Q. What is the purpose of your direct testimony in this proceeding?**

A. Given the strong and growing customer demand for distributed generation and other DERs like energy storage, and other related policy drivers in place, IREC believes North Carolina would benefit greatly from substantial interconnection process reforms and improvements. I am providing this testimony to highlight various mechanisms that the state could adopt to help increase transparency, which may in turn help mitigate some of the substantial ongoing disputes and persistent contentiousness among all parties involved in the process. At this time, IREC is particularly interested in improving the interconnection process for smaller-scale distributed generation projects. Improving the efficiency of the utility's review process for small projects can help free up utility staff time and resources such that they can focus on those projects requiring full study. Improving the efficiency of the process also helps ensure North Carolina customers have a fair and efficient path to interconnection. When contrasting the process in North Carolina with states that have similar levels of DERs interconnecting to the grid, we identified that there is room for improvement and opportunities to create a more efficient review process for smaller projects.

To that effect, IREC proposes revisions to the Procedures that would help ensure timely and efficient interconnection of smaller projects without unnecessary, time-consuming, and expensive studies, while still protecting safety and reliability of the grid. Ultimately, with improved interconnection processes in place, customers, developers, and utilities will benefit from and gain confidence in the process over time. In addition, the Commission and its staff will realize the benefits of a more streamlined process, which will very likely reduce time and resources spent grappling with disputes and ongoing related challenges.

North Carolina has a thriving renewable energy market. All of the renewable energy projects operating in the state are operational today thanks to the diligent efforts of customers, developers, utilities, and regulators. With the passage of House Bill 589 ("H.B. 589")[1], there are a number of changes underway that have the potential to lead to increased opportunities for DER deployment in the state. Ensuring an effective interconnection process is essential to continuing the

[1] N.C.S.L. 2017-192.

success of the state's renewable energy market while also maintaining a safe and reliable electric system.

As a stakeholder involved in the 2015 effort and the 2017 Working Group, it is IREC's observation that interconnection has been a source of contention among North Carolina customers, developers, and utilities, despite admirable collaborative efforts from parties. The interconnection process for projects of all sizes continues to take considerably longer than it does in other leading renewable energy markets. In this testimony, IREC focuses on identifying ways to increase the efficiency of the process by utilizing well-established screening and grid transparency practices that can minimize the number of lengthy interconnection studies required, in order to free up utility resources to focus on the projects that truly require more detailed or bespoke review processes.

**Q. Please summarize your key points and recommendations.**

A. Despite the utilities' efforts over the past five years to clear the substantial backlog of interconnection requests, North Carolina's interconnection queue remains full of projects that are not moving forward in a timely and efficient manner. The queue remains extremely backlogged, with, for example, more than half of projects languishing for more than a year in Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's (collectively, "Duke") queues without completing study and receiving an Interconnection Agreement.[2] This has resulted in a long list of potentially avoidable disputes between utilities and interconnection customers.[3] This proceeding presents an important opportunity for

[2] Quarterly Interconnection Queue Performance Reports & Quarterly Interconnection Queue Status Reports filed by Duke Energy Progress and Duke Energy Carolinas, N.C.U.C. Docket No. E-100, Sub 101A (Oct. 11, 2018).

[3] *See, e.g.*, Settlement Agreement, N.C.U.C. Docket No. E-100, Sub 101 (Aug. 29, 2016) (settling dispute between Duke and 33 interconnection customers regarding Duke's unilateral implementation of "circuit stiffness review screen"); Complaint & Motion for Injunctive Relief filed by Salisbury Solar, LLC and Bear Poplar Solar, LLC, N.C.U.C. Docket No. E-7, Sub 1123 (Oct. 31, 2016) (alleging Duke's failure to comply with study timelines set by Procedures); Complaint & Motion

the Commission to take a close look at the current Procedures and determine what is working, and what is not, and—ultimately—what changes are in the best interest of customers.

In our Testimony, Mr. Brian Lydic and I recommend that the Commission revise its Procedures so that the Fast Track screens work as they do in other states and jurisdictions, allowing a reasonable number of projects to pass. Duke's Fast Track pass rate of *two percent* is unreasonable when compared to its utility peers with similar amounts of interconnected DERs.[4] In addition to modifications to the Fast Track screening process proposed in the testimony of Mr. Brian Lydic, I discuss IREC's support for raising the size limit for Fast Track eligibility of DERs located on distribution lines that have a voltage of < 5 kV from 100 kW to 500 kW. Finally, the Procedures should allow all projects that fail the Fast Track screens the opportunity for Supplemental Review.

The most impactful changes that the Commission can make to North Carolina's interconnection process are to increase its transparency. For example, publishing the distribution system's interconnection queue and modifying quarterly reporting requirements will illuminate why projects are getting stuck in the queue, how often this occurs, and what opportunities there are to improve process efficiencies. Such increased transparency into the interconnection process will provide the Commission information about the extent of missed deadlines and outcome of proposed projects. This allows the Commission to better understand the reasons for North Carolina's persistent interconnection backlog and inform strategies to improve the situation going forward.

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for Injunctive Relief filed by Wadesboro Solar, LLC, N.C.U.C. Docket No. E-7, Sub 1124 (Oct. 31, 2016) (alleging same); Complaint filed by Fresh Air II, LLC, N.C.U.C. Docket No. E-7, Sub 1148 (June 15, 2017) (alleging same); Complaint filed by Fresh Air XXIV, LLC, Fresh Air XXIII, LLC, and Fresh Air XXVIII, LLC, N.C.U.C. Docket No. E-7, Sub 1149 (June 14, 2017) (alleging same, as well as Duke's failure to comply with Procedures for improper withdrawal from queue).

[4] **Exhibit SBA-Direct-8,** Duke's Response to IREC Data Request 1-3c.

Another area where the Commission has the opportunity to increase transparency is the development of hosting capacity maps that describe the current state of the grid. IREC asks the Commission to convene a stakeholder working group to, with utilities, develop hosting capacity maps that provide customers the information necessary to propose DERs in areas that are much less likely to require costly upgrades or time-consuming system impact studies.

Although publishing more information is valuable to improving the process and remediate persistent challenges, enhanced transparency measures are not enough to unclog North Carolina's interconnection queue. As such, IREC also proposes that the Commission create a timeline enforcement mechanism and appoint an Interconnection Ombudsman to oversee a robust alternative dispute resolution process.

Finally, IREC suggests the Commission reject unreasonably large fee increases unless supported in the record by certain cost data, which Duke acknowledges it does not track. Regardless of merit, the Commission should not entertain a proposal, such as this one including a 1,000 percent fee increase, that violates the regulatory principle of gradualism.

## II. The Commission should adopt revisions to the Fast Track screening process, require defined screens for Supplemental Review, and ensure that Supplemental Review is available to all Fast Track eligible projects.

**Q. What issues are addressed in this section of your testimony?**

A. I begin by describing the Fast Track screening process. Then, I recommend that Supplemental Review be open to all Fast Track eligible projects and discuss IREC's proposed changes to the eligibility limit for DERs interconnecting to low voltage lines.

### A. North Carolina's Fast Track screening process is ineffective at processing DER interconnection applications in a timely and efficient manner.

**Q. Please describe the Fast Track process found in Section 3 of the Interconnection Procedures.**

A. In the Fast Track process, a set of standardized screens are applied, which evaluate whether a proposed project seeking to interconnect is likely to require full study under Section 4 to be able to determine whether it can interconnect safely, with or without upgrades. The screens utilize conservative limits that are defined to filter out projects that have any potential for safety or reliability impacts. These screens are, at this juncture, well-established and have been used successfully across the country to efficiently interconnect most new DERs. If a project fails one or more of the screens, it is then directed to Supplemental Review or to the full study process. Fast Track is an essential part of the Procedures because it increases efficiency by allowing eligible projects to avoid the multi-month (or potentially longer) study process on the condition that they pass a set of technical screens. Without an effective Fast Track and Supplemental Review process, all proposed projects would go through full study—many unnecessarily—and as explained below, North Carolina already has a problematic backlog of projects awaiting study.

A number of IREC's proposed changes to the Procedures involve the Fast Track and Supplemental Review process set forth in Section 3 and, indirectly, the Small Inverter Process in Section 2.[5] IREC is particularly interested in ensuring

[5] Section 2 of the Interconnection Procedures provides for an expedited review process for projects below 20 kW using a certified inverter based generator (commonly known as the small inverter process). This process allows for the use of a combined interconnection application and agreement to more quickly

effective use of Fast Track as it is an important tool to ensure safe interconnections in an efficient manner. Unfortunately, it appears that the Fast Track process has not been operating effectively in North Carolina, resulting in more projects receiving further review than is necessary.

**Q. Why do you believe that the Fast Track process is not operating effectively?**

A. I believe the Fast Track process is not operating effectively because of the inordinately high number of projects that fail the Fast Track screens. Duke provided data that show, according to the records it keeps, that out of 259 projects submitted for Fast Track approval, only five passed the Fast Track screen from May 2015 – October 2018.[6] That is an average of less than two projects per year, and failure rate of 98 percent.

**Q. How does a 98 percent Fast Track failure rate compare with the operation of Fast Track in other jurisdictions?**

Duke's Fast Track failure rate is extremely high compared to other jurisdictions. When compared to other utilities in the country with similar levels of DERs interconnecting to the grid, IREC is not aware of another utility that has a Fast Track failure rate for small projects (< 1 MW) anywhere near Duke's 98

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interconnect projects, but relies on the same technical screens as used in the Fast Track process. *See* North Carolina Interconnection Procedures ("NCIP") § 2.2.1. For ease of use, IREC will refer to the Fast Track process generally but notes that the changes recommended should also benefit these small projects utilizing the Section 2 process.

[6] **Exhibit SBA-Direct-8,** Duke's Response to IREC Data Request 1-3c. Duke does not track in electronic format the number of projects that pass or fail the Fast Track screen, so it "requires a significant amount of manual effort" for Duke to provide this data. *Id.* As discussed below, the Commission should require Duke to record this data in an electronic format.

percent.[7] The utilities in Hawaii are the one exception to this. However, the comparatively high volume of DERs on the grid and the unique island grid infrastructure make for an ill-suited comparison to Duke Energy's service territory in North Carolina.

**Q. Is the application of the Fast Track screens different in North Carolina than in other jurisdictions?**

A. Mr. Brian Lydic provides testimony for IREC that discusses the application of specific Fast Track screens in North Carolina and other jurisdictions. As an electrical engineer, he is well positioned to discuss the application of the screens.

**Q. Does Duke apply the Fast Track screens to small inverter-based projects under 20 kW?**

A. No, Duke instead uses a "demand table screening process."[8]

**Q. Is the use of the "demand table screen process" concerning to you?**

A. I do not know enough about it at this time to draw any conclusions. It is concerning that Duke is using a screen not discussed in its tariff, and one that may contradict the Fast Track screens that the tariff instructs the utility to apply.

**Q. What is the size limit for Fast Track projects, and is Fast Track commonly used?**

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[7] For example, IREC conducted phone interviews with utility engineers at Pacific Gas & Electric and San Diego Gas & Electric in January 2018, and both utilities confirmed that even today the vast majority of their net energy metered projects (NEM) under 1 MW are able to be interconnected in under ten days. Collectively the California utilities processed over 110,000 applications for small projects a year and are still able to keep projects moving through the Fast Track screens in a highly efficient manner. *See* Go Solar California, California Distributed Generation Statistics, www.californiadgstats.ca.gov (accessed Nov. 13, 2018).

[8] **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-3b.

A. Fast Track is currently available to projects under 2 MW.[9] To date, many proposed projects in North Carolina were at or near the former 5 MW standard offer contract limit, and thus ineligible for Fast Track.

**Q. Do you anticipate that North Carolina will continue to see a small number of Fast Track projects?**

A. No, I expect to see an *increase* in the number of Fast Track eligible projects. Historically, North Carolina has seen a high rate of larger (3 – 5 MW) projects proposed for interconnection, likely due to the then-existing standard offer rates and contract terms for Qualifying Facilities under PURPA for projects up to 5 MW. However, H.B. 589 reduced the eligibility cap for standard offer rates and contracts down to 1 MW for up to 100 MW of new capacity, and then down to 100 kW.[10] The utilities agree that they will see an increase in the volume of small scale solar interconnections.[11] Because these projects' margins may be thin, it is especially important that North Carolina's Procedures be efficient and minimize unnecessary delay, while ensuring projects are interconnected safely and reliably.

In addition to the legislation discussed above, on October 29, 2018, Governor Roy Cooper signed Executive Order No. 80. In Section 4, it mandates the creation of a North Carolina Clean Energy Plan "that fosters and encourages the utilization of clean energy resources, including energy efficiency, solar, wind,

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[9] NCIP § 3.1.

[10] H.B. 589, N.C.S.L. 2017-192, § 1(b).

[11] Joint Reply Comments of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Dominion Energy North Carolina, N.C.U.C. Docket No. E-100, Sub 101 (March 12, 2018) ("Joint Utilities Reply Comments"), at 12.

energy storage, and other innovative technologies." This plan may result in more government action that encourages the development of small scale renewable energy resources, including energy storage.

As of November 2, 2018, Duke reported that it is aware of over 160 pending energy storage projects, mostly from residential customers with on-site generation.[12] All of the energy storage projects not owned by Duke will not export energy to the grid.[13] As the price of battery storage continues its decline and consumer awareness of these products increases, I believe that North Carolina will see an increase in the quantity of non-exporting energy storage interconnection requests that qualify for Fast Track.

H.B. 589 also authorized Duke to apply for permission to create a Green Source Advantage program. This program, expected to launch in 2019, could bring 600 MW more renewable energy capacity to Duke's service territory.

Finally, a new rebate program for net energy metering ("NEM") projects[14] is likely to increase the number of small residential and commercial distributed generation systems.

With this projected increase in the number of applications eligible for and well-suited to use Fast Track review, it is critical for the Commission to ensure now that the Fast Track and Supplemental Review processes are functioning

[12] **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-5a.

[13] **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-5a.

[14] Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Application Requesting Approval of Solar Rebate Program, N.C.U.C. Docket Nos. E-2, Sub 1167; E-7, Sub 1166 (Jan. 22, 2018).

properly, in order to avoid further exacerbation of the queue backlog and to reduce the cost of distributed energy development in the state.

**Q. Under the current Interconnection Procedures, what are the fees and timelines for projects that use the small inverter-based review, Fast Track review, and Supplemental Review processes?**

A. Under the current rules, after payment of a $100 fee, a project that proceeds through the small (20 kW and under) inverter-based review process in Section 2 should typically be able to complete the interconnection review process and have a signed Interconnection Agreement in hand within 15 Business Days, if it passes the screens.[15]

Second, a project that passes the Fast Track screens under the existing standards should be able to sign an Interconnection Agreement within 25 Business Days after their application is deemed complete and a fee of between $100 and $500 paid (varies by size).[16]

However, if a Small Inverter or Fast Track process applicant fails the Fast Track screens and is invited to undergo Supplemental Review, it will be required

[15] NCIP § 2.2.1 & Attachment 6. Note that projects that require minor construction may take longer.

[16] NCIP §§ 3.2, 3.2.2, & Attachment 2.

to submit an additional deposit of $250[17] and the process could take up to 35 *additional* Business Days plus time for a possible Customer Options meeting.[18]

B. A Fast Track failure rate of 98 percent is unreasonable and uncommon.

**Q. How many projects pass the small inverter based review, Fast Track review, and Supplemental Review screens?**

A. It does not appear that Duke tracks the number of projects pass or fail the small (20 kW and under) inverter based review screen, as Duke was unable to answer a Data Request involving this Data.[19] As described in more detail below, the Commission should require Duke to track and record this data in an electronic format.

Duke does not track in electronic format the number of projects that pass or fail the Fast Track screen, so it "requires a significant amount of manual effort" for Duke to provide this data.[20] As described in more detail below, the Commission should require Duke to record this data in an electronic format. Duke provided data that shows out of 506 projects above 20 kW, only ten passed its Fast Track screen from 2015 – October 2018.[21] That is an average of three projects per year, and failure rate of 98 percent.

[17] **Exhibit SAB-Direct-8,** Attachment to Duke's Response to IREC Data Request 1-4g. IREC is not aware how often Duke charges a $250 deposit for supplemental review, as it did in the attached example, versus how often it charges a different amount.

[18] See NCIP Sections 3.3 and 3.4 for associated timelines. It is not clear if the utilities are typically requiring a customer options meeting for small projects.

[19] **Exhibit SAB-Direct-8,** Duke's Response to IREC Data Request 1-3b.

[20] **Exhibit SAB-Direct-8,** Duke's Response to IREC Data Request 1-3b.

[21] **Exhibit SAB-Direct-8,** Duke's Response to IREC Data Request 1-3c.

It is unclear if Duke tracks in electronic format the number of projects that pass or fail the Supplemental Review screens. As described in more detail below, the Commission should require Duke to record this data in an electronic format. Duke provided data that shows from May 2015 – October 2018, 3 of 154 projects failed the Supplemental Review screen, a failure rate of 2 percent.[22]

**Q. Do these failure rates raise any concerns for you?**

A. Yes. The extraordinarily high Fast Track failure rate results in the vast majority of projects being sent to Supplemental Review. As a result, the review process can take *35 Business Days* longer, plus time for the Customer Options meeting, and the customer must pay the additional fee for the Supplemental Review. Then, after the Supplemental Review process, the vast majority of those projects are approved to interconnect. If the Fast Track screens were applied in manner consistent with utilities in other jurisdictions that have a similar levels of DER, I would expect more projects to pass Fast Track, and less projects to need the more labor-intensive Supplemental Review.

C. A defined Supplemental Review Process, available to all projects that fail Fast Track, will enhance efficiency.

**Q. What changes do you propose to the Supplemental Review Process?**

A. I propose that the Procedures allow all Fast Track eligible projects that fail Fast Track to proceed to a robust Supplemental Review process with defined screens. My proposed revisions can be found in Sections 3.3.2-3.3.3 of the redline attached as **Exhibit SBA-Direct-2.**

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[22] **Exhibit SAB-Direct-8**, Duke's Response to IREC Data Request 1-3c.

**Q. Why should all projects that fail the Fast Track screens be afforded the opportunity to proceed to Supplemental Review?**

A. Affording all projects the opportunity to proceed to Supplemental Review provides interconnection customers the information necessary to make an informed decision regarding the future of the project. Once provided the written results of the Supplemental Review process, a customer can understand the potential technical issues that may require a study or upgrades. The result of the Supplemental Review process informs the customer's decision to either pursue a time consuming and costly full study process under Section 4, modify the project to alleviate the impacts that the utility identified, or abandon the project. It is in the best interest of both the utility and the customer that only projects the customer determines to be viable, based on an informed understanding of system impacts, move forward to the full study process under Section 4. Simply put, without the results of the Supplemental Review, projects that are not viable may proceed unnecessarily to a full study under Section 4 and projects that are viable may be abandoned after failing the Fast Track screens.

**Q. How did the utilities respond to IREC's proposal to allow all projects that fail Fast Track the opportunity to proceed to Supplemental Review?**

A. In the utilities initial comments, they opposed allowing all projects that fail Fast Track to proceed to Supplemental Review. Instead, they claim the utility is in the "best position" to determine whether the project should be in Supplemental

Review or the full study process under Section 4.[23] However, if a customer is denied Supplemental Review, she will have to choose between moving on to an expensive and time-consuming full study or abandoning her project. Supplemental Review should be available to all Fast Track eligible projects, to allow them an intermediate step that should result in further information about interconnecting their project, before having to make this decision. In addition, this open-ended utility discretion with no obligation to provide reasons or justification, provides a ripe opportunity for the appearance of, or actual, discriminatory treatment of projects.

**Q. Why should the Supplemental Review process use defined screens?**

A. This issue is address in the testimony of Mr. Brian Lydic.

D. The Fast Track eligibility limit for DERs connecting to locations on the grid with low voltage lines should be raised to reflect national best practices.

**Q. What is the purpose of the Fast Track size limit?**

A. The purpose of limiting Fast Track eligibility by size is to filter out projects that would be highly unlikely to pass the Fast Track screens and instead direct them immediately towards the full study process under Section 4. This overall size limit serves an administrative function for utilities to help sort projects into the proper study track. It is not centrally a safety or reliability limit, but rather a heuristic that allows utilities to bypass the administrative burden of running the Fast Track screens for projects that are extremely likely to fail those screens.

**Q. What is the Commission's current size limit for Fast Track eligibility?**

[23] Joint Initial Comments of the Utilities, N.C.U.C. Docket No. E-100, Sub 101 (Jan. 29, 2018) ("Utilities' Initial Comments"), Att. 1, at 8.

A. In 2015, the Commission adopted a table-based approach for Fast Track eligibility. The table found in Section 3.1 of NCIP is reproduced below (internal citations omitted).

Table 1: NCIP Fast Track Eligibility for Inverter-Based Systems

| Line Voltage | Fast Track Eligibility Regardless of Location | Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation |
|---|---|---|
| < 5 kV | ≤ 100 kW | ≤ 500 kW |
| ≥ 5 kV and < 15 kV | ≤ 1 MW | ≤ 2 MW |
| ≥ 15 kV and < 35 kV | ≤ 2 MW | ≤ 2 MW |

**Q. What is your proposal regarding the size limit for Fast Track eligibility?**

A. The size limit for Fast Track eligibility for DERs seeking to connect to distribution lines that have a voltage of < 5 kV, regardless of location, should be raised to 500 kW. The current limit of 100 kW is too conservative, and may unnecessarily send relatively small projects, mostly NEM projects, to full study under Section 4. The technical screens in the Fast Track process are robust and serve to identify projects needing study, therefore the size eligibility limits do not need to duplicate or go beyond the screens.

IREC believes the best approach in setting this threshold is to allow the largest sized project that could potentially pass the interconnection screens on the particular line size to use the Fast Track procedures. If the project is too large, the screens will prevent the project from interconnecting without study. If the size limit is too low, projects could be forced into a multi-month, expensive full study process unnecessarily. In other words, the screens will catch projects that are "too large," and thus the purpose of the eligibility limit is simply to improve administration of the rules. Please see the testimony of Mr. Brian Lydic for further information regarding the Fast Track screens. Other states, identified below, have readily adopted thresholds like the one IREC proposes here.

**Q. What other jurisdictions use North Carolina's 100 kW threshold for all projects on a line with a voltage of < 5 kV?**

A. IREC has not engaged in any other jurisdiction that limited Fast Track eligibility for < 5 kV circuits at the 100 kW or lower level as North and South Carolina do. The 500 kW threshold was adopted by FERC with expressed support from a diverse group of stakeholders including the major utility industry associations, IREC, National Renewable Energy Laboratory, and Solar Electric Industry Association,[24] making it the *de facto* national standard. The support of the major utility industry associations, *i.e.*, the National Rural Electric Cooperative Association, Edison Electric Institute, and American Public Power Association, is notable because many of their members operate older distribution systems with low voltage lines. Subsequent to FERC's adoption of this threshold in the SGIP, every state that has since revisited the Fast Track portion of its interconnection standards adopted the 500 kW threshold, except for North and South Carolina.[25] For example, Iowa adopted a 500 kVA threshold while Ohio, where Duke also

[24] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2015), at P 97, note 202.

[25] IREC is aware of recent updates to interconnection standards in California, Illinois, Iowa, Massachusetts, Minnesota, New York, and Ohio that use a threshold at or above the 500 kW level.

operates, and Illinois a 500 kW threshold.[26] Also, IREC's proposal for North Carolina to adopt the national standard was supported by Public Staff during the 2015 revisions of these Procedures.[27] The thresholds found in Section 2.1 of FERC's SGIP are reproduced in the following table (internal citations omitted). IREC continues to believe that adopting this table is the appropriate approach, but at a minimum believe that raising the limit for < 5 kV circuits is important.

Table 2: FERC SGIP Fast Track Eligibility for Inverter-Based Systems

| Line Voltage | Fast Track Eligibility Regardless of Location | Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation |
|---|---|---|
| < 5 kV | ≤ 500 kW | ≤ 500 kW |
| ≥ 5 kV and < 15 kV | ≤ 2 MW | ≤ 3 MW |
| ≥ 15 kV and < 30 kV | ≤ 3 MW | ≤ 4 MW |
| ≥ 30 kV and ≤ 69 kV | ≤ 4 MW | ≤ 5 MW |

**Q. What was the Commission's rationale in adopting a standard that differs from FERC's national standard?**

A. In 2015, The Commission stated that "during this interim period when the goal is to clear the clogged queue, it is counterintuitive to increase the Fast Track eligibility . . . which would divert resources to potentially fruitless projects and results."[28] Today, over three years later, this rationale does not hold. The queue

[26] Iowa Amin. Code r. 199-45.7(2); Ill. Admin. Code tit. 83, pt. 466.80(b); Ohio Admin. Code 4901:1-22-07(3).

[27] SGIP Section 2.1; Order Approving Revised Interconnection Standard, N.C.U.C. Docket No. E-100, Sub 101 (May 15, 2015) ("2015 Order"), at 16.

[28] 2015 Order at 17.

remains clogged, and without changes to the procedures and activities of the utilities, this "interim" period will become permanent. Studying more projects does not alleviate the problem, rather allowing more projects to efficiently be reviewed through Fast Track's technical screens might. Second, as described herein, a much larger quantity of small projects are expected in the coming years, and sending those projects through an extensive study process is a poor use of utility staff time and resources, and will continue to exacerbate the queue backlog and discourage customers from being able to install DERs to manage energy costs and serve their own load.

**Q. What was the size limit in FERC's SGIP standard prior to adopting the current standard?**

A. In the former iteration of the FERC SGIP, and in many states' current procedures, Fast Track review is limited to systems up to 2 MW, or 2,000 kW. Interestingly, North Carolina's current Procedures include a more restrictive size limit than found in the current and former SGIP. IREC's proposal in this case is for the Commission to adopt the smallest threshold allowed under FERC's current SGIP and, as discussed below, to increase the transparency of the queue backlog.

## <u>III. Transparency and accountability are key to ensuring the Procedures operate effectively.</u>

**Q. What role does transparency and accountability play in the operation of Interconnection Procedures?**

A. Transparency and accountability are key to ensuring the Interconnection Procedures function properly. Adequate transparency measures reveal how projects progress through the queue, how Fast Track screens are applied, what the outcomes of studies are, and whether timelines are met. Without such information, the Commission, interconnection customers, and other involved stakeholders have no idea whether the Procedures are working effectively, are being applied correctly, or if any changes to the Procedures are warranted. Increasing transparency regarding how utilities are processing applications—especially in the form of a detailed public queue—has myriad benefits which substantially outweigh the minor drawbacks. It helps developers track their projects and see where backlogs are, so they have realistic expectations about delays they may need to plan for. It helps ensure projects are treated in a non-discriminatory manner. And it provides the Commission the data it needs to make informed decisions about how to improve the interconnection process and ensure projects are being treated fairly.

Further, transparency is integral to ensuring accountability: without an understanding of whether the utilities are meeting deadlines and other obligations under the rules, there is no way for them to be held accountable for those obligations except through individual complaints. Relying on individual complaints is inefficient and ineffective to ensure compliance across the board, for all customers and projects. For example, it is not guaranteed enforcement, because it places the burden on customers to file a complaint against utilities, which they may be hesitant to do since the utilities are ultimately the gatekeepers to their projects getting built and interconnected. In addition, the time it requires to resolve a dispute is not practical for projects concerned about the impact of yet further delays.

**Q. What transparency provisions are included in the current rules?**

A. In the 2015 revisions to the Procedures, the Commission took the important step of adding reporting requirements, with the intent of (1) providing developers with an understanding of the current queue and an opportunity to assess where their project might be in the queue, and to (2) providing the Commission with information about the utilities' queue performance.[29] Currently, the Procedures require the utilities to provide two quarterly reports. The first is a "snapshot" of the interconnection queue, which shows information about a project and its place in the queue and whether it has been denied or withdrawn.[30] The second is a report by the utilities on how long it is taking projects to move from submission of the Interconnection Request to a signed Interconnection Agreement, and from execution of the Interconnection Agreement to date of interconnection.[31] These reports only include information on larger DG projects. The Commission and stakeholders have no regular visibility into how utilities are processing applications for smaller projects

**Q. Do these quarterly reports provide sufficient information to stakeholders and the Commission?**

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[29] 2015 Order at 24.
[30] *Id.* at 25-26
[31] *Id.*

A. While requiring these quarterly reports was a step in the right direction, they have not resulted in sufficient transparency for all stakeholders to ensure that the projects are moving through the queue as they should. The queue snapshot does not provide information about how long it took specific projects to progress through certain parts of the process, nor does it provide information regarding the outcome of studies and screens.

The quarterly reports have revealed that, despite the last revisions to the Procedures, North Carolina's interconnection queues remain extremely backlogged, with, for example, more than half of projects languishing for more than a year in Duke's queues without completing study and receiving an Interconnection Agreement.[32] This reporting, however, does not provide the information necessary to determine *why* the queue remains so clogged. There are no specifics about what stages take long, no specific reporting of screen pass rates, or any ability to sort between projects to understand which ones have more trouble proceeding efficiently. This is not nearly enough information to identify the source of the problem and fix it—it merely reveals that the backlog exists.

The utilities' assurances that they are using "good utility practice," without further evidence of such, does not provide the Commission with sufficient evidence upon which it can make a decision.[33] Indeed, it became clear during the

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[32] Quarterly Interconnection Queue Performance Reports & Quarterly Interconnection Queue Status Reports filed by Duke Energy Progress and Duke Energy Carolinas, N.C.U.C. Docket No. E-100, Sub 101A (Oct. 11, 2018).
[33] *State ex rel. Utilities Commission v. Carolina Water Service, Inc.*, 335 N.C. 493, 504 (1994) (reversing a Commission decision that was not supported by substantial evidence where the Commission "failed to provide any fact-specific

2017 Working Group process that the utilities had little motivation to share any sort of detailed information to allow insight into their process: as explained in the North Carolina Sustainable Energy Association's ("NCSEA") initial comments, requests for more detailed information were rebuffed.[34] Where there is evidence that there have been serious problems with management of the interconnection process—as is the case here in North Carolina—it is essential that the Commission exercise this oversight and regulatory authority and require more information from the utilities, so it can understand what may be causing the problems and adopt solutions.

**Q. Are there other reasons that the Commission should modify its reporting requirements?**

A. Yes, there are several additional reasons that the Commission should modify its reporting requirements. First, during the 2017 stakeholder process IREC discovered that Duke had been applying the 15% of peak load screen in a manner inconsistent with how other utilities and states apply this screen. More detail regarding the application of the 15% of peak load screen can be found in the testimony of Mr. Brian Lydic. This resulted in nearly all projects failing Fast Track and moving to Supplemental Review or full study, which naturally leads to longer waits for projects in the queue and more backlog during the study process. Had the Procedures required reporting regarding whether projects passed or failed

support" for its determination and failed to follow approved practice for making that determination).

[34] NCSEA's Initial Comments, N.C.U.C. Docket No. E-100, Sub 101 (Jan. 29, 2018), at 22.

Fast Track, and which screens were failed, this problem could have been identified much earlier and potentially remedied. This could have saved the utility precious time that could have been better spent focusing on projects that do indeed require Supplemental Review or a full study, and could have saved customers time and money. It is possible that further transparency would result in similar cost and time saving insights.

Second, the lack of information presents considerable challenges to all parties, including the Commission, in determining where and how such improvement can be most cost-effectively and efficiently made. Transparency is an important first step that should not be overlooked in this revision effort. IREC strongly recommends that the Commission require and enforce necessary transparency measures such that the lack of publicly available information about interconnection does not continue to impair the adoption of viable solutions to improve the current process challenges.

Finally, the competitive procurement process in H.B. 589 essentially requires this increased transparency. Under the new law, utilities will now be allowed to participate in the competitive procurement process, and the law requires that a utility share any information that it uses to prepare a proposal in order to ensure a fair competition.[35] To guarantee the fairness intended by the law, the utilities should be required to make public much of the data they have on queue progress and their application of the Procedures. In addition, if this

[35] H.B. 589, N.C.S.L. 2017-192, § 2.(a).

information is not made public, it will be impossible to tell if Duke is giving preference to its own projects or otherwise using the interconnection process to undermine the competitive bidding process. The Public Utility Regulatory Policies Act ("PURPA") requires that utilities provide a fair and non-discriminatory interconnection process,[36] and this is particularly crucial when the utility is competing for those same projects.

**Q. What changes do you propose to the Interconnection Procedures' reporting requirements?**

A. IREC recommends a two-pronged approach to transparency: a detailed public queue, along with regular reporting on information that is not available in the public queue. The public queue provides more granular detail regarding individual projects' status in the queue, while the less frequent quarterly reports would summarize data to allow identification of trends. As Duke adds the ability to electronically track more data regarding its interconnection queue in its Salesforce software, it is important that the Commission require transparency, *i.e.*, the publication of this data on the internet.

A. The Commission should require the utilities to publish a public distribution system interconnection queue.

**Q. Please describe your proposal for a public interconnection queue.**

A. The public queue should be posted on the utilities' websites in a downloadable and sortable format, such as an Excel spreadsheet, and updated

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[36] *See* 18 C.F.R. § 292.303(c) & *Am. Paper Inst. v. AEP Service Corp.*, 461 U.S. 402, 418 (1983) (explaining obligations of utilities to interconnect qualifying facilities).

monthly. IREC proposes that the Commission's order require the publication of a distribution system queue including the data fields found in **Exhibit SBA-Direct-3**. Of particular importance are disclosure of the dates that allow visibility into project progress through major milestones in the process, and information about the Fast Track and Supplemental Review screens that were failed. Information identifying specific customers should be anonymized.

**Q. Do other jurisdictions require publication of an distribution system interconnection queue?**

A. Yes, a similar approach has already been adopted in multiple jurisdictions across the country. For example, the California Public Utility Commission requires the publication of a distribution system interconnection queue to allow stakeholders to better understand the interconnection process.[37] Massachusetts requires disclosure of similar information, which utilities provide in detailed monthly reports regarding the status of all interconnection applications to the State Department of Energy Resources, which then uses this information to generate public information identifying the type and quantity of DER projects currently in

[37] *See* Pacific Gas and Electric Company (PG&E), https://www.pge.com/pge_global/common/word_xls/for-our-business-partners/interconnection-renewables/energy-transmission-and-storage/wholesale-generator-interconnection/PublicQueueInterconnection.xls, (accessed Nov. 13, 2018); San Diego Gas & Electric Company, https://www.sdge.com/more-information/customer-generation/wdat-rule21-generation-interconnection-queue, ("SDG&E WDAT & Rule 21 Interconnection Queue") (accessed Nov. 13, 2018); Southern California Edison Company (SCE), https://www.sce.com/wps/portal/home/regulatory/open-access-information (accessed Nov. 13, 2018) ("Public WDAT-Rule 21 Queue").

the queue.[38] Other states including Maryland,[39] Minnesota,[40] New York,[41] and Hawaii publish similar data.[42] Some states do not post a public queue for NEM projects, but, as described above, here it is critical that we get a better picture of how small projects are being evaluated and thus suggest a queue or detailed reports is necessary even for small projects.

**Q. Will publishing a distribution system queue result in a significant burden on utilities?**

A. No, because all utilities are obligated to follow and maintain compliance with the timelines in the rules, the information to be included in the public queue is all information that the utilities should already be tracking in their day-to-day management of interconnection applications. The utilities can simply make it their procedure to update the public queues at the same time that they update their own records. Updating public queues with this already-maintained information may give the utilities modest additional responsibilities, but the benefits of the transparency far outweigh any burden. The information that IREC recommends be

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[38] *See* Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (Jan. 31, 2017), https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improves-the-interconnection-exp.

[39] Md. Code Regs. 20.50.09.06.L.3.

[40] Order Establishing Updated Interconnection Process and Standard Interconection [sic] Agreement, Minnesota Public Utilities Commission Docket E-999/CI-16-521 (August 13, 2018), at 4.

[41] *See* New York State Department of Public Service, *SIR Inventory Information*, *http://www3.dps.ny.gov/W/PSCWeb.nsf/All/286D2C179E9A5A8385257FBF003F1F7E?OpenDocument* (accessed Nov. 13, 2018)

[42] *See* Hawaiian Electric, *Integration Tools and Resources*, https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue (accessed Nov. 13, 2018)

included in a public queue will help all parties—including the utilities—evaluate actual conditions and respond accordingly. This will increase efficiency, reduce costs, and help lighten the burden on the queue, as customers make better-informed decisions.

**Q. Does Duke currently track the information that IREC proposes be included in the queue?**

A. In the majority of circumstances, yes. It is not a burden for Duke to publish this data, which is already tracked in its electronic database.

Of the 23 data fields IREC proposes for inclusion in the public interconnection queue, I am certain that Duke currently tracks 16.[43] Of the 7 data fields I am uncertain about, 3 were added recently and thus IREC has not asked Duke about,[44] 3 Duke clearly stated it does not track,[45] and in 2 cases Duke provided an unclear answer.[46]

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[43] **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-4f. (Duke current tracks Application and/or Queue Number, Facility Capacity, Primary Fuel Type, Exporting or Non-Exporting, City, Zip Code, Substation, Feeder, Status, Date Application Deemed Complete, Date of Notification of Fast Track Screen Results, Date of Notification of Supplemental Review Results, Date of Notification of Impact Study results, Date of Notification of Facilities Study Results and/or Construction Estimates, and Date Final Interconnection Agreement is Provided to Customer.)

[44] IREC recently added the following three data fields to its proposal for a public interconnection queue: Capacity of the transformer to which the project will interconnect, Date agreement is signed by both parties, and Date Interconnection Facilities are completed and available for operation by the Interconnection Customer.

[45] Duke clearly stated it does not track: Secondary fuel type, Supplemental Review Results, and Date of final interconnection cost paid to utility. **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-4f.

[46] When asked if it tracks "Fast Track Screen Results (pass or fail, and if fail, identify the screens failed)," Duke responded that it does not track this information, but "these are captured within the Fast Track page." *Id.*

IREC is particularly concerned that Duke is not tracking electronically the results of its Supplemental Review, Fast Track, and small invert-based project screens. As noted above, Duke indicated that it "requires a significant amount of manual effort" to compile the number of projects that passed and failed the Fast Track screen,[47] and was unable to answer a Data Request involving the number of projects that passed or failed the small <20 kW inverter based review screen.[48]

**Q. Why is IREC concerned that Duke is not tracking electronically the outcome of its Supplemental Review, small inverter-based review, and Fast Track screens?**

A. IREC believes that utilities should track this data. It is necessary for all stakeholders and the Commission to monitor whether these streamlined review processes are being applied properly to ensure minimal queue backlog. Understanding the failure rates of the screens gives the Commission insight into what portions of the grid are reaching high penetration and would enable it to consider proactive solutions before they become major problems. Providing visibly into the characteristics of specific projects that pass and fail the screens allows developers to make informed decisions regarding their own projects' prospects.

Tracking should be in an electronic format so that it is easy to report and publish data on a regular basis, instead of involving significant manual effort.

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When asked if it tracks "Date of grant of permission to operate," Duke responded that DEC does not track this information, while DEP does. *Id.*

[47] **Exhibit SAB-Direct-8,** Duke's Response to IREC Data Request 1-3b.

[48] **Exhibit SAB-Direct-8,** Duke's Response to IREC Data Request 1-3b.

In conclusion, the Commission should order the utilities to publish a distribution system interconnection queue with the data fields found in **Exhibit SBA-Direct-3.** Duke already tracks the vast majority of the items IREC proposes including in the queue, and the few items it does not track constitute key data that should be available to utilities, the Commission, and stakeholders.

B. <u>The Commission should modify its quarterly reporting requirements.</u>

**Q. Please describe your proposal to modify the quarterly reporting requirements for interconnection process statistics.**

A. In addition to the public queue, IREC recommends that the Commission's order continue to require quarterly reporting from the utilities, but with more information that summarizes queue data and provides data about the pre-application process. This information, described in more detail in **Exhibit SBA-Direct-4,** should include compiled data from the public queue and information on processing of Pre-Application Reports and Interconnection Applications, including statistics on Fast Track, Supplemental Review, the study process, and the outcome of proposed projects.

Significantly, I incorporate Strata Solar's proposal to track and report missed timelines in Section 4 of **Exhibit SBA-Direct-4**. These modifications will give the Commission and stakeholders insights regarding how the interconnection process is working (or not working), and allow problems to be addressed promptly. This is an improvement over the current situation, where problems regarding queue backlog were not considered until this regularly scheduled revision of the Procedures.

**Q. Have other regulatory bodies recognized the need for more transparency to understand the causes of Duke's queue backlog and address the issue of fair competition between the utility and developers in competitive procurement?**

A. Yes, on October 31, 2018, the Public Service Commission of South Carolina ("PSC SC") issued a decision adopting reporting requirements proposed by IREC designed to understand the impact of the CPRE group study on the overall queue in the state. The PSC SC opined:

> Concern exists regarding the backlog of the Companies' existing queues that are administered under the South Carolina Generator Interconnection procedures. As a result, Duke shall report the <u>status of its queue, the reasons for the backlog, and its plan to remedy the problem</u> to the Commission within 30 days of the date of this order. ORS is requested to follow up with an investigation and also report on the status of the queue within 30 days of the date of the Companies' report. Duke shall follow up quarterly with a status report regarding the queue and ORS is requested to verify this update.[49]

The PSC SC contemplates that the reports will include information and aggregate statistics regarding:

- successful and unsuccessful CPRE bids;
- "the intervals for every significant milestone for every queued ahead non-CPRE project, including intervals for receipt of System Impact and Facilities Studies Agreements, for the System Impact and Facilities Studies to be completed, for when studies are completed and the Interconnection Agreement is received, and for when the Interconnection Request is received to execution of Interconnection Agreement;"[50]
- the allocation of staff to processing interconnection studies "on a per-project and per-megawatt basis;

[49] Pub. Serv. Comm. of S.C.; Dkt. 2018-202-E; Commission Directive, pp. 2-3 (Oct. 31, 2018) (emphasis added).

[50] *Id.*

- [i]nformation on Interconnection Study Intervals for System Impact Studies and Facilities Studies for CPRE versus non-CPRE projects;
- [i]nformation on Interconnection Study Backlogs for CPRE versus non-CPRE projects; and
- [t]he number of CPRE versus non-CPRE projects that achieved each significant interconnection milestone (i.e. system impact study complete, facilities study complete, IA signed, interconnection achieved) during the reporting period. This information shall also be included in the quarterly report currently provided to ORS and the SCSBA pursuant to the February 26, 2016 Memorandum of Understanding approved by the Commission in Docket No. 2015-362-E."[51]

IREC's proposal for detailed reporting in this docket includes much of the same information required by the PSC SC, but adds additional detail because it is designed to look beyond the CPRE group study program.

**Q. What is your response to utilities concerns with the increased reporting requirement?**

A. The utilities oppose a proposal that would require them to track any missed deadlines and regularly report those missed deadlines to the Commission.[52] Their reasoning is that this is "[a]lready addressed in Reasonable Efforts language."[53] But requiring a utility to make reasonable efforts and tracking when deadlines are not met are two different things. By this logic, the requirement that a utility make "reasonable efforts" would mean that deadlines have no meaning, and this cannot be the case. Interconnection of DER is a business transaction that ultimately impacts customers and costs to all involved parties, and per the Procedures, the

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[51] *Id.*

[52] *See* Utilities' Initial Comments, Att. 1, at 6.

[53] Utilities' Initial Comments, Att. 1, at 12.

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utilities' time to execute their responsibilities is not open-ended. It also does not meet the standard of review here.

The proposal for reporting compliance with deadlines would simply allow the Commission to track whether the utilities are meeting their obligations under the Procedures. The utilities provided no explanation of why this will not be helpful to provide needed insight into the status of the interconnection process and compliance with identified timelines.

C. The Commission should require utilities to develop hosting capacity maps to direct generators to locations where interconnection will not provoke major upgrades.

**Q. Please describe a hosting capacity map.**

A. Hosting capacity maps are a tool provided by a utility that identifies locations on its distribution grid where there is available capacity to interconnect additional DERs, and areas where the interconnection of additional DERs would require costly grid upgrades. Requiring utilities to prepare a hosting capacity, or "heat" map, indicating locations with ample capacity for interconnection is the best way to identify areas where the utility's distribution system can support additional DERs and communicate this information to customers. Without a hosting capacity map, customers have no information regarding the best and worst locations for new DER. Hosting capacity maps transparently provide this information to customers and the Commission. IREC prepared a detailed guide for regulators on this topic. IREC's guide discusses the improvements hosting capacity maps provide to interconnection requests, distribution system planning, and locational benefits of distributed energy resources; various methodologies for developing hosting capacity maps; and case studies on their use. *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources* is attached as **Exhibit SBA-Direct-6**.

**Q. In what format do utilities publish hosting capacity maps?**

A. The ideal format—adopted by Pepco in the Mid-Atlantic,[54] in California,[55] New York,[56] and Minnesota[57]—would be for utilities to publish online an interactive map of their entire network that can enable potential interconnection customers to initially obtain basic system and queue information about their proposed point of interconnection, and eventually see exactly how much capacity there is available on the circuit for additional DERs. Figures 1-3 provide an example of a hosting capacity map for Pacific Gas & Electric Company.

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[54] *See* Potomac Electric Power Company, *Hosting Capacity Map*, https://www.pepco.com/MyAccount/MyService/Pages/DC/HostingCapacityMap.aspx (accessed Nov. 13, 2018).

[55] SDG&E, *Enhanced Integration Capacity Analysis (ICA)/LNBA Maps*, https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica (accessed Nov. 13, 2018); PG&E, *Distribution Resources Plan*, https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2017-distribution-resource-plan-and-request-for-offers.page (accessed Nov. 13, 2018)("Integration Capacity Map"); SCE, *Distribution Energy Resource Interconnection Map*, http://on.sce.com/derim (accessed Nov. 13, 2018).

[56] Joint Utilities of New York, *Utility Specific Hosting Capacity*, http://jointutilitiesofny.org/ utility-specific-pages/hosting-capacity/ (accessed Nov. 13, 2018) (listing access links to each utility's map).

[57] Xcel Energy, *Hosting Capacity Map*, https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map (accessed Nov. 13, 2018).

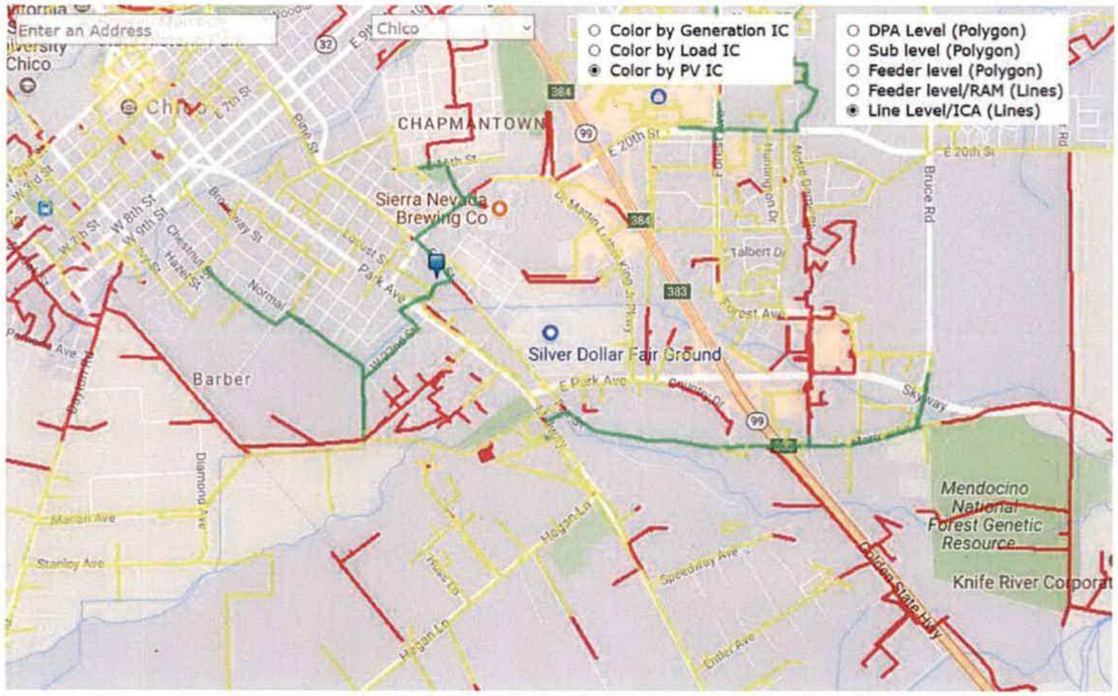
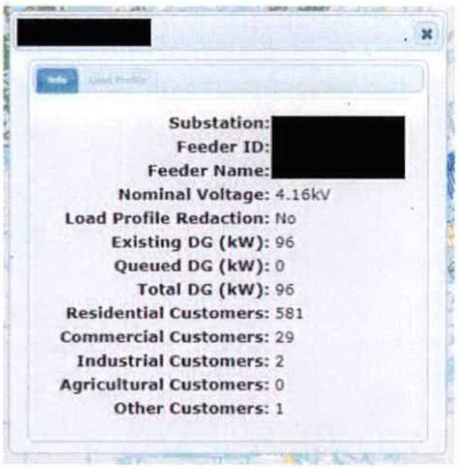
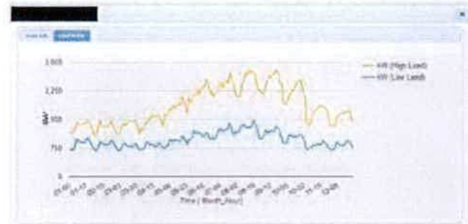



Figure 1: Hosting Capacity Map for Pacific Gas & Electric Company

Figure 2 provides the information revealed when one selects a specific node or line segment on the map.

Figure 2: Detailed Data Provided for Each Node in a Hosting Capacity Map for Pacific Gas & Electric Company



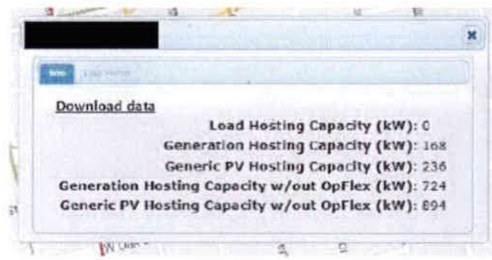
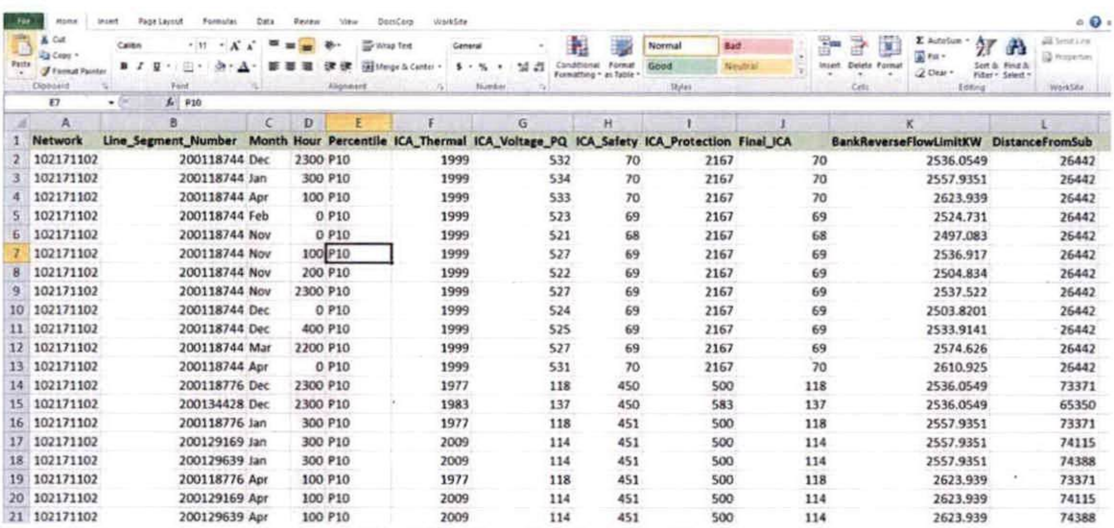




Figure 3 shows the data from the hosting capacity analysis, as is provided by Pacific Gas & Electric Company in a downloadable format.

Figure 3: Hosting Capacity Analysis Results in a Downloadable Format



| | Network | Line_Segment_Number | Month | Hour | Percentile | ICA_Thermal | ICA_Voltage_PQ | ICA_Safety | ICA_Protection | Final_ICA | BankReverseFlowLimitKW | DistanceFromSub |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 102171102 | 200118744 | Dec | 2300 | P10 | 1999 | 532 | 70 | 2167 | 70 | 2536.0549 | 26442 |
| 3 | 102171102 | 200118744 | Jan | 300 | P10 | 1999 | 534 | 70 | 2167 | 70 | 2557.9351 | 26442 |
| 4 | 102171102 | 200118744 | Apr | 100 | P10 | 1999 | 533 | 70 | 2167 | 70 | 2623.939 | 26442 |
| 5 | 102171102 | 200118744 | Feb | 0 | P10 | 1999 | 523 | 69 | 2167 | 69 | 2524.731 | 26442 |
| 6 | 102171102 | 200118744 | Nov | 0 | P10 | 1999 | 521 | 68 | 2167 | 68 | 2497.083 | 26442 |
| 7 | 102171102 | 200118744 | Nov | 100 | P10 | 1999 | 527 | 69 | 2167 | 69 | 2536.917 | 26442 |
| 8 | 102171102 | 200118744 | Nov | 200 | P10 | 1999 | 522 | 69 | 2167 | 69 | 2504.834 | 26442 |
| 9 | 102171102 | 200118744 | Nov | 2300 | P10 | 1999 | 527 | 69 | 2167 | 69 | 2537.522 | 26442 |
| 10 | 102171102 | 200118744 | Dec | 0 | P10 | 1999 | 524 | 69 | 2167 | 69 | 2503.8201 | 26442 |
| 11 | 102171102 | 200118744 | Dec | 400 | P10 | 1999 | 525 | 69 | 2167 | 69 | 2533.9141 | 26442 |
| 12 | 102171102 | 200118744 | Mar | 2200 | P10 | 1999 | 527 | 69 | 2167 | 69 | 2574.626 | 26442 |
| 13 | 102171102 | 200118744 | Apr | 0 | P10 | 1999 | 531 | 70 | 2167 | 70 | 2610.925 | 26442 |
| 14 | 102171102 | 200118776 | Dec | 2300 | P10 | 1977 | 118 | 450 | 500 | 118 | 2536.0549 | 73371 |
| 15 | 102171102 | 200134428 | Dec | 2300 | P10 | 1983 | 137 | 450 | 583 | 137 | 2536.0549 | 65350 |
| 16 | 102171102 | 200118776 | Jan | 300 | P10 | 1977 | 118 | 451 | 500 | 118 | 2557.9351 | 73371 |
| 17 | 102171102 | 200129169 | Jan | 300 | P10 | 2009 | 114 | 451 | 500 | 114 | 2557.9351 | 74115 |
| 18 | 102171102 | 200129639 | Jan | 300 | P10 | 2009 | 114 | 451 | 500 | 114 | 2557.9351 | 74388 |
| 19 | 102171102 | 200118776 | Apr | 100 | P10 | 1977 | 118 | 451 | 500 | 118 | 2623.939 | 73371 |
| 20 | 102171102 | 200129169 | Apr | 100 | P10 | 2009 | 114 | 451 | 500 | 114 | 2623.939 | 74115 |
| 21 | 102171102 | 200129639 | Apr | 100 | P10 | 2009 | 114 | 451 | 500 | 114 | 2623.939 | 74388 |

for Pacific Gas & Electric Company

The ideal hosting capacity maps would include detailed hosting capacity data for each node, along with substation, circuit, and feeder information. However, even a simple color-coded "heat map" of lines and substations to show areas with available capacity (green), those approaching limits (yellow), and those at or exceeding capacity limits (red), along with basic circuit information would go a long way to helping developers site projects. This map could also indicate circuits where the transformer capacity has been exceeded. This, in turn, would help alleviate backlogs in the queue, as it would enable customers to avoid incompatible sites and/or would help them plan for a longer duration review process by being able to anticipate needed upgrades. Figures 4-5 show a more simple hosting capacity map prepared by Pacific Gas & Electric Company several years ago.

Figure 4: Basic Hosting Capacity Map for Pacific Gas & Electric Company

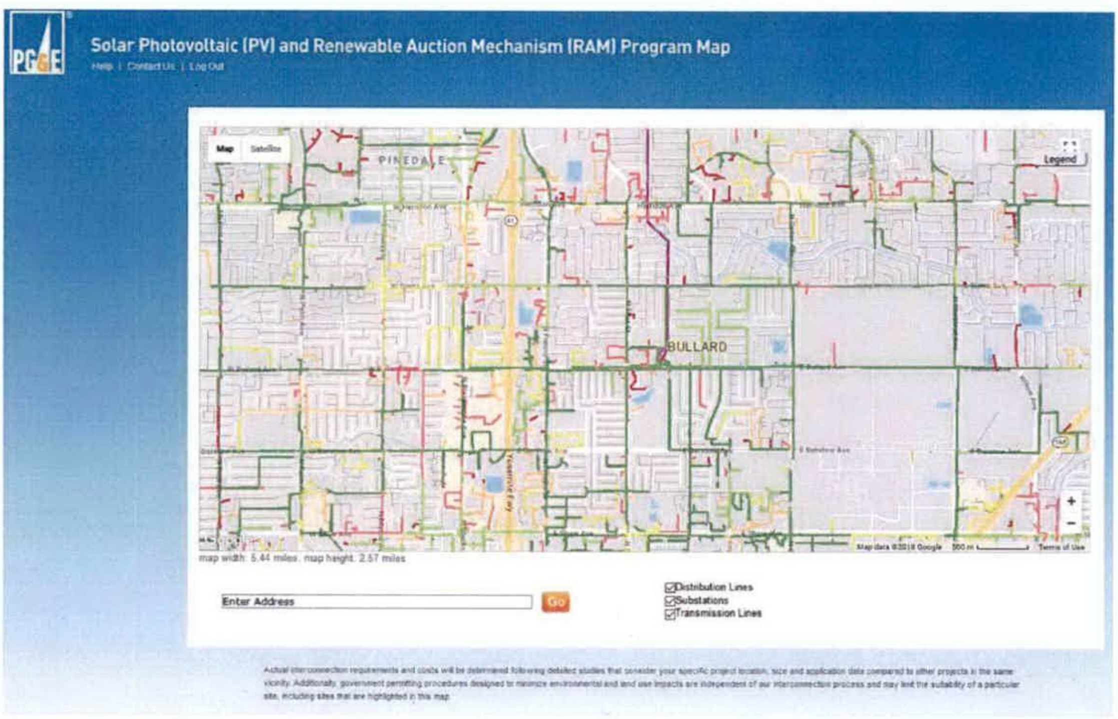



Figure 5 provides the information revealed when one selects a specific feeder on the basic hosting capacity map.

Figure 5: Basic Feeder Data for Pacific Gas & Electric Company

**BULLARD 1109**

1 of 15

Asset Info | DER Capacity

| | |
|---|---|
| ZoneId | 253961109.001 |
| Feeder Name | BULLARD 1109 |
| Feeder Number | 12 |
| Nominal Circuit Voltage (kv) | Null |
| Circuit Capacity (MW) | 10.76 |
| Circuit Projected Peak Load (MW) | 6.29 |
| Substation Bank | 2 |
| Substation Bank Capacity (MW) | 44.55 |
| Substation Bank Peak Load (MW) | 40.31 |
| Existing Distributed Generation (MW) | 1.093013 |
| Queued Distributed Generation (MW) | 0 |
| Total Distributed Generation (MW) | 1.093013 |
| zoneMapALL2.Zone | 1 |
| PVCIRCUITS_ED.CircuitID | Null |

**Q. Has the Commission expressed an interest in directing customers to locations where generators can interconnect without costly upgrades?**

A. Yes, in approving Tranche 1 of the CPRE program, the Commission expressed an interest in considering several issues before authorizing subsequent tranches of the CPRE program.[58] One issue that the Commission expressed an interest in exploring was "options for Duke to more specifically direct generators to locations on the system that will not involve major network upgrades."[59]

**Q. What is the difference between a hosting capacity map and the data needed for the CPRE program?**

A. The CPRE program includes large projects that are more likely to interconnect the utility's transmission system. Hosting capacity maps focus exclusively on the utility's distribution system, providing customers useful locational data for smaller projects that connect to the distribution system. The information provided in a hosting capacity map is much more detailed than would be disclosed about a utility's transmission system. If any CPRE projects are small enough to connect to the distribution system, a hosting capacity map would assist the developer in selecting a location for that project.

**Q. Please describe your proposal regarding Hosting Capacity Maps.**

A. IREC recommends that the Commission direct the utilities to prepare a hosting capacity analysis, with the ultimate goal of using the maps to streamline

[58] N.C. Util. Comm., Dkt. E-100, Sub 101, Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 Of CPRE RFP (Oct. 5, 2018).

[59] *Id.* at 13.

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the interconnection process. In furtherance of this goal, IREC recommends that the Commission convene a working group to develop a proposal including the:

- methodology utilities will use for the hosting capacity analysis,
- frequency at which the analysis is updated,
- extent of the grid included in the analysis,
- format and data of the results that will be published, and
- way that utilities will use the results to streamline review of interconnection requests.

IREC's proposal for information to be included in a Hosting Capacity Map, attached as **Exhibit SBA-Direct-5**, does not include a specific recommendation for the use of the maps in the interconnection process today, through the working group should consider that ultimate goal of this process.

**Q. Please summarize the benefits of Hosting Capacity Maps.**

A. Hosting Capacity Maps have a wide variety of benefits in states with high DER penetration like North Carolina, and many more states are exploring their adoption and implementation. The maps in California, New York, Minnesota, and Hawaii have helped to direct developers to more optimal grid locations, reducing queue congestion and lowering the overall cost of project development (particularly in cases where there is a competitive procurement process in place such as in North Carolina).[60] This is a brief excerpt of the numerous benefits that these maps provide. Please see **Exhibit SBA-Direct-6** for a more complete discussion of the benefits resulting from the publication of hosting capacity maps.

[60] For more on the benefits of hosting capacity and heat maps, see Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (Jan. 31, 2017), https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improves-the-interconnection-exp#gs.32SkmNQ.

In addition to measures that increase transparency, IREC also recommends several measures to increase accountability.

## IV. Along with transparency, the Commission should ensure all parties are held accountable for their obligations under the procedures.

**Q. Are the transparency measures you propose sufficient to address the current backlog in North Carolina's interconnection queue?**

A. Measures to increase transparency can frequently lead to enhanced accountability with regard to deadlines without the need for any sort of penalty or enforcement action. That said, because of the large, unprecedented delays in processing interconnection applications in North Carolina, penalties, deposit refunds, or some other sort of enforcement mechanism is likely necessary at this stage. If, based upon enhanced reporting, it appears that the utilities are continually failing to meet their deadlines in the revised interconnection process, IREC believes it may be appropriate to consider methods of making the interconnection timelines more meaningful for the utilities. Put simply, North Carolina will not "unclog" its interconnection queue backlog without accountability mechanisms that apply to both utilities and interconnection customers.

**Q. Do you propose any specific accountability mechanisms for this Commission's Interconnection Procedures?**

A. Yes, IREC recommends that the Commission adopt a timeline enforcement mechanism, enhance its dispute resolution process through the appointment of an Interconnection Ombudsman, and include clear timelines in the Procedures.

<u>A. The Commission should adopt a timeline enforcement mechanism.</u>

**Q. Please describe the timeline enforcement mechanism.**

A. IREC recommends that North Carolina adopt an enforcement mechanism similar to the one being used in Massachusetts: a "timeline enforcement mechanism" (or, "TEM"), which provides positive and negative earnings adjustment for utilities to encourage compliance with the timelines set forth in the procedures.[61] Utilities track compliance with each timeline in the procedures through metrics published in the public queue, or provided in separate reports. Under the TEM, each utility calculates the total aggregate average time, in business days, that it has taken to interconnect projects on each track over the past year, starting from the date an application is received until the date an interconnection service agreement is executed. Each utility then compares that calculation with the total aggregate number of business days that its interconnection tariff allows for the projects on each track. When the utility's annual report shows that its performance has deviated from the aggregate allowed timeframes by more than five percent in one direction or the other, the utility will either incur a penalty or earn offsets that it can carry forward into the next reporting year.

**Q. Does the TEM proposal require strict compliance with the timelines in the Interconnection Procedures for every project?**

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[61] Order on a Timeline Enforcement Mechanism, Mass. Dept. of Public Utilities Docket No. 11-75-F, Appx. B (July 31, 2014).

A. No. The advantage of this method is that it recognizes that 100% compliance with each individual project is likely unrealistic in light of the many demands on utility time and the need to manage emergencies and other circumstances. It thus tracks the overall compliance with the timelines in total and then determines a penalty or credit based upon that. This approach could likewise work well for North Carolina.

B. The Commission should improve the dispute resolution process by creating an Interconnection Ombudsman.

**Q. Please describe the dispute resolution process included in the Procedures.**

A. Section 6.2 of the Interconnection Procedures governs disputes. It allows a party to provide a written Notice of Dispute to the other, and if the dispute is not resolved in ten business days, Public Staff are available to help informally resolve the dispute. If informal resolution is unsuccessful, either party may file a complaint.[62] This process is quite limited and in need of improvement in order to help facilitate timely resolution of conflicts.

**Q. What are the goals of an alternative dispute resolution procedure?**

A. A well-defined alternative dispute resolution procedure puts all the facts before a mutually-respected neutral party who provides a recommendation for a mutually satisfactory solution expeditiously.

**Q. Is the current dispute resolution procedure meeting these goals?**

[62] NCIP §§ 6.2.2 – 6.2.3.

A. No. Recent disputes regarding queue management and implementation of new study guidelines highlights the need for a clearly defined dispute resolution process in North Carolina.[63]

**Q. Please describe your proposal to create an Interconnection Ombudsman.**

A. IREC's suggested revision of Section 6.2, found in **Exhibit SBA-Direct-2,** proposes a dispute resolution process that adopts features from California and Massachusetts, and is similar to what was recently adopted in Minnesota. The central feature of this process is the inclusion of an interconnection ombudsperson at the Commission who could help facilitate resolution of disputes.

The process requires parties to first attempt to work together to amicably resolve the dispute within a specified timeframe. The process recognizes that there is a need to resolve disputes about timelines more rapidly than other types of disputes and provides an accelerated timeline for these types of disputes. If parties are unable to resolve disputes by working together, they may seek assistance from the interconnection ombudsperson or an outside mediator to resolve the dispute.

There is, however, flexibility regarding what type of dispute resolution process is most appropriate. For example, IREC's experience in other states has shown that it is very helpful to have a designated party that can help mediate disputes if parties wish to have a balanced process that helps avoid formal complaints.

[63] *See* footnote 3, above.

**Q. Would you consider other alternative dispute resolution approaches in the Interconnection Procedures?**

A. Yes, I am open to discussing alternate dispute resolution approaches that could further define the process currently in place in North Carolina, so parties better know how to address and what to expect when addressing disputes.

**Q. How do the utilities respond to IREC's dispute resolution proposal?**

A. The utilities also oppose any revisions to the Procedures' dispute resolution provision. They reason that providing an ombudsperson is "inconsistent with treatment of disputes for retail customers,"[64] but they do not explain why this poses a problem. Retail customers and interconnection customers are very differently situated. Interconnection customers have paid the utilities thousands of dollars to be able to interconnect their systems, and rely on the utilities to carefully apply the Procedures and comply with contractual agreements. The sorts of disputes interconnection customers might have with the utilities are simply different, and likely more complex, than those disputes a retail customer might have. Thus, a different, and clearly defined, dispute resolution process for interconnection customers makes sense.

<u>C. The Commission should ensure that the procedures contain clear and reasonable timelines.</u>

**Q. What purpose do the timelines in the Interconnection Procedures serves?**

A. Including clearly defined timelines for all major steps in the process ensures that projects keep moving through the process without undue delay and

[64] Utilities' Initial Comments, Att. 1, at 11.

sets forth clear expectations for all parties.[65] This, in turn, minimizes the chance for disputes, which cost parties more time and money. The timelines should be realistic and reasonable to reflect the development process and the challenges associated with obtaining financing and other necessary permits, but should not allow projects to sit for extended durations with no action. Such delays impact other later-queued projects that may be prepared to move ahead. Timelines should be meaningful and apply to both applicants and the utility. Defined timelines for all steps of the interconnection process are especially important here, where it is clear that it is taking an excessively long time for projects to interconnect.[66]

**Q. What is your proposal regarding timelines in the Interconnection Procedures?**

A. The Interconnection Procedures should ensure that each action in the procedures has a timeline that is specific and reasonable. I incorporated NCSEA's proposal to set ten business day timelines for notice of screen failure in Section 2.2.2, as well as for sending invoices and refunds in Section 6.3. In Section 2.3.1 of Attachment 6, I incorporated NCSEA's proposal for the utility to provide a

[65] *See, e.g.*, Cal. Pub. Utils. Comm. Decision 12-09-018 (Sept. 13, 2012), at 36-37 ("[A] major contributing factor to the need for Rule 21 reform is the absence of specific timelines beyond Initial Review. The Proposed Settlement takes a major step forward in this regard by setting out timelines for completing an interconnection request and obtaining queue position, Fast Track (including both Initial Review and Supplemental Review), and the Independent Study Process. Importantly, timelines are also established for developers of distributed generation, in terms of responding to utility requests for information, meeting to discuss study results, and posting financial security to move ahead in the process."); Order on a Timeline Enforcement Mechanism, Mass. Dept. of Public Utilities Docket No. 11-75-F, at 1-11 (discussing and approving the distributed generation working group's proposed interconnection timeline enforcement mechanism, which measures each utility's performance in meeting interconnection timelines, and was developed as required by the state legislature, St. 2012, c. 209, § 49).

[66] *See generally* Quarterly Interconnection Queue Performance Reports & Quarterly Interconnection Queue Status Reports filed by Duke Energy Progress, Duke Energy Carolinas, and Dominion Energy North Carolina, N.C.U.C. Docket No. E-100, Sub 101A.

written statement of generator test results within ten business days of the test. These proposals can be found in the redline attached as **Exhibit SBA-Direct-2.**

**Q. All of your accountability proposals apply to utilities; are there accountability mechanisms that apply to interconnection customers?**

A. Yes. The Procedures allow a utility to deem an interconnection request withdrawn if customers to do not cure an incomplete application, or a lapse in site control, in ten business days.[67] Additionally, a utility may deem an interconnection request withdrawn upon a customer's failure to act on a Facilities Study Agreement or payment and Financial Security in sixty business days, and a complete Facilities Study or complete Interconnection Agreement in ten business days.[68] These are real deadlines with serious consequences for interconnection customers that fail to comply. A withdrawn application results in loss of queue position which is critically important for certain projects. Should utilities find that interconnection customers are failing to respond to other reasonable requests in a timely manner, IREC would consider supporting additional accountability measures for customers as well.

**Q. Please summarize the need for the accountability mechanisms you propose.**

A. While IREC appreciates the overriding need to ensure that utilities can manage the complex electrical system safely and reliably, they are also responsible for ensuring open access to that system for interconnection customers. They are also now going to be competing with those customers for projects and need to ensure a fair and non-

[67] NCIP §§ 1.4.4, 1.6.
[68] NCIP §§ 4.4.1, 5.2.2, 5.2.4.

discriminatory process for H.B. 589 to be effective. Customers are being asked to put down substantial financial deposits upfront and pay large fees, thus it is reasonable to expect the utilities to respect those commitments by keeping the study process moving. When the study process is not moving smoothly, customers should have access to an effective dispute resolution process.

## VI. The Commission should require further documentation to justify the requested changes to the fees.

**Q. What are the fees currently and proposed to be charged to interconnection customers?**

A. The table below indicates the fees that the utilities proposed to charge interconnection customers, and the increase from the current fees.

Table 3: Interconnection Fees

| | **Existing Fee** | **Proposed Fee** | **Percent Increase** |
|---|---|---|---|
| Pre-Application Report Fee | $300 | $500 | 167% |
| Interconnection Request Application Fee for Inverter-Based Generating Facility < 20 kW | $100 | $200 | 200% |
| Fast Track Interconnection Request Application Fee for projects between 20 kW - 100 kW | $250 | $750 | 300% |
| Fast Track Interconnection Request Application Fee for projects between 100 kW - 2 MW | $500 | $1,000 | 200% |
| Transfer of Ownership/Control Fee | $50 | $500 | 1,000% |
| Supplemental Review Deposit for projects between 20 kW - 100 kW | $250 | $750 | 300% |
| Supplemental Review Deposit for projects between 100 kW - 2 MW | $500 | $1,000 | 200% |

**Q. Are the fee increases reasonable?**

A. No, the increases proposed by the utilities are unreasonably large. As described below, IREC does not believe that the utilities' evidence provided in this docket meets their burden to justify the fee increases. Regardless of merit, the proposed fee increases also constitute rate shock. If the Commission disagrees regarding the merit of the proposed increases, it should adhere to the regulatory principle of gradualism and modify fee increases that range from 167 percent to, extraordinarily, 1,000 percent.

**Q. What costs are interconnection fees designed to recover?**

A. IREC supports interconnection fees that compensate utilities for time *efficiently spent* processing interconnection applications. However, fees should be set with the expectation that utilities are acting efficiently and using best practices when processing applications.

**Q. Does the Commission have enough evidence in the record to approve new interconnection fees?**

A. The Commission should reject increased fees based on the record in this docket to date. First, the fee proposal was raised late in the stakeholder process, so it did not undergo full review by the 2017 Working Group. Second, the information provided by Duke to date does not provide sufficient information regarding how fee revenues are being spent, so the Commission is unable to make an informed review of Duke's proposal. Similarly, the Commission does not have enough evidence before it to support the need for new interconnection fees.

For example, "Duke Energy does not track average costs or expenses specifically for processing a <20 kW Interconnection Request or a Fast Track Interconnection Request, and therefore has no data reasonably available to provide

[the] 'average cost' information."[69] Without a break down of expenses by fee category, such as how much is spent processing a <20 kW application versus a Fast Track application, it is impossible for the Commission to determine if the increased fees proposed by the utilities for those activities are reasonable based on the cost the utility incurs for that activity. In another example, Duke proposes to increase the transfer of ownership fee from $50 to $500, a 1,000 percent increase. Without tracking of how much time or money is spent by the utility to process such requests, the Commission will not have enough information to determine that this proposed 1,000 percent increase is reasonable. This detailed cost information, with expenses broken out by fee charged, is necessary to understand the reasonableness of Duke's proposal.

My concern is that interconnection in North Carolina has been comparatively slow and inefficient, and the fees proposed are relatively high compared to other states. Fees should compensate utilities only for time *efficiently spent* processing interconnection applications.

**Q. Has Duke made efforts to increase the granularity of its interconnection cost tracking?**

A. Yes. Duke implemented a new charging methodology in late 2017 that increases the categories of costs it tracks.[70] This includes separate charging for hours and expenses based on type of work supported. Upon hearing of this change, IREC was hopeful that it would yield useful cost data that could be mapped to the

[69] **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-6.
[70] **Exhibit SBA-Direct-9**, Duke's Response to Public Staff Data Request 8-2.

individual fees in the Procedures. Unfortunately, the categories Duke specified for cost tracking do not align with the fees in the Procedures. The categories Duke established are:

- Fees-Recovered Work,
- Study-Recovered Work, and
- Construction Cost-Recovered Work.[71]

It appears that costs related to *all* the fees are collected in one account, titled "Fees-Recovered Work." Without cost-tracking categories that align with the individual fees charged, the costs that Duke is currently tracking will provide limited value in informing the Commission's decision regarding the level the fees should be set at.

**Q. What are comparable fees in other jurisdictions?**

A. FERC's SGIP includes a pre-application report fee of $300, the application fee for an inverter-based system up to 10 kW is $100, and the application fee for Fast Track-eligible projects up to 5 MW is $500.[72] In Ohio, the pre-application report fee is $300,[73] application fee for an inverter-based system up to 25 kW is $50,[74] and Fast Track application fee is $150 for a 100 kW system ($50 plus $1 per kW).[75] In Illinois, the pre-application report fee is $300,[76] application fee for

[71] **Exhibit SAB-Direct-9**, Duke's Response to Public Staff Data Request 8-2.
[72] FERC SGIP § 1.2.2; Attachment 2 to FERC SGIP; Attachment 3 to FERC SGIP.
[73] Ohio Admin. Code 4901:1-22-04(B)(2).
[74] Ohio Admin. Code 4901:1-22-06(D)(1).
[75] Ohio Admin. Code 4901:1-22-07(F)(1).
[76] 83 Ill. Admin Code part 466.45(a).

an inverter-based system up to 25 kW is $50,[77] and expedited review application fee is $200 for a 100 kVA system ($100 plus $1 per kVA).[78] In Virginia, the application fee for all systems up to 500 kW is $100.[79] In contrast, utilities seek a pre-application report fee of $500, an application fee of $200 for inverter-based systems up to 20 kW, and an application fee of $750 for systems up to 100 kW.

Table 4: Interconnection Fee Comparison

| **Jurisdiction** | **Pre-application report fee** | **Small inverter-based system application fee** | **Fast Track application fee for 100 kW or 100 kVA systems** |
|---|---|---|---|
| Ohio | $300 | $50 | $150 |
| Illinois | $300 | $50 | $200 |
| Virginia | n/a | $100 | $100 |
| FERC SGIP | $300 | $100 | $500 for systems up to 5 MW |
| North Carolina - current | $300 | $100 | $250 |
| North Carolina - Utilities' Proposal | $500 | $200 | $750 |

Notably, the California utilities have been required to track and disclose their interconnection costs, which reveal much lower costs than Duke is claiming.[80] For example, for projects of under 1 MW, the California utilities report that it costs between approximately $35 and $101 to process an interconnection

[77] 83 Ill. Admin Code part 466 Appendix A.
[78] 83 Ill. Admin Code part 466 Appendix C.
[79] 20 Va. Admin. Code § 5-314-40(B).
[80] *See* **Exhibit SBA-Direct-10**, California Net Energy Metering Interconnection Costs.

application.[81] While it is true that the California utilities process far more applications than Duke does, and thus benefit from economies of scale, Duke has not provided an explanation of why the disparity between its proposed fees and the fees found in other jurisdictions is so vast.

**Q. What is your response to Duke's rationale supporting its proposed fees?**

A. Duke explained that some of the increase in fees is necessary to cover the cost of new systems intended to increase efficiency, like Salesforce. I agree that it is a good thing that Duke is employing these systems, but they are supposed to increase efficiency and make costs go down—not up. For example, California utilities have dramatically increased their efficiency, as explained in a report by NREL:

> Time savings and increased business process efficiency translate to direct cost savings for the utility. . . . PG&E's projected cost decrease from 2012 to 2015 translates to a total cost savings of $25.8 million over 4 years. With a total upfront investment of $1.5 million for [standard net energy metered] enterprise software, process streamlining, and other back-end information technology systems integration, PG&E has recuperated their original investment 16 times over, as measured by direct processing cost savings. In addition to quantifiable, direct, cost saving, PG&E's improvement measures also yielded improved customer relations and compliance with regulatory requirements.[82]

Another example of declining costs can be found in an EPRI report discussing a process implemented by San Diego Gas & Electric (SDG&E) that

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[81] *Id.*

[82] Kristen Ardani & Robert Margolis, *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric*, NREL, p. 7 (Sept. 2015), http://somossolar.com/wp-content/uploads/2016/02/decreasing-soft-costs.pdf

enabled the utility to go from processing 475 applications a month to over 1,200 a month. While SDG&E's process improvements did require an upfront investment, the changes *paid for themselves* within a year and were expected to "accrue annual cost savings ranging between $1.9 million and $3.2 million, and to benefit from ~$10 million in cumulative avoided costs by the end of the 4-year period."[83] This is a stark contrast to the increased costs Duke is identifying. The Commission should seek more information from Duke before approving its requested increases because it appears that the fees will place a disproportionate, and unjustified, burden on smaller projects.

In light of this evidence clearly demonstrating that it is entirely possible for a utility to interconnect projects safely and reliably in less time and for less cost, I believe the Commission should not grant the fee increases at this time and should instead require Duke to undergo an efficiency review that determines why its costs are so much higher than those of utilities similarly situated.

**Q. What justification should the Commission require the utilities provide when establishing interconnection fees?**

A. The Commission should require utilities to better explain the need for the increase in fees, an explanation of the efforts the utility is taking to ensure that it is processing applications efficiently and, why costs have not gone down despite the efficiencies it has adopted. In addition to that narrative, utilities should:

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[83] EPRI, Solar PV Market Update, PV Integration Case Study - SDG&E's Distributed Interconnection Information System (June 2014), at 4.

1. Break down expenses by fee category, such as how much time and money is spent processing each type of application.
2. Break down expenses by of level review, such as pre-application report, Fast Track, Supplemental Review, and full study.
3. Provide the fees charged in other jurisdictions in which the utility operates.

**Q. Apart from the cost of the fee, what other concerns do you have about Duke's fee proposal?**

A. Duke has proposed a change to Section 1.4.1.2, regarding what costs an interconnection request deposit may be applied to. The existing language allows utilities to apply the deposit to "the Utility's reasonably anticipated costs for conducting the System Impact Study and the Facilities Study." Duke proposes to expand this language to also allow utilities to recover for associated "overhead." I understand from IREC's communications with Duke is that it has already been including overheads in its charges to deposits. However, before enshrining this change in the Procedures, the Commission should ask Duke to explain what these overheads include, and what their cost is so that it is clear what the impacts of this change could have.

## VIII. Conclusion

**Q. What are you observations of the 2017 Working Group process?**

A. IREC observed during the 2017 Working Group process that there seemed to be significant distrust between solar developers and the utilities, which prevented the parties from reaching consensus on many issues. A particular point of conflict revolved around the persistent interconnection queue backlog, which continues to result in unreasonably long study timelines for projects. On top of this, Duke has twice issued new, unilateral "guidelines" for interconnection, which have resulted in more study and further delay of projects, and have slowed the queue. In some cases, Duke has relied on the "guidelines" to outright deny projects the opportunity to interconnect. Indeed, in the middle of the 2017 stakeholder process, Duke released new guidelines to limit where projects can be interconnected, relying on a technical argument that is unprecedented. This would have the effect of killing many developers' projects and curtailing future development.

In IREC's experience, this sort of conflict emphasizes the critical importance of using this opportunity to make revisions to the Procedures, ensuring they are clearly drafted and provide enhanced transparency for all involved parties, as well as establishing a more collaborative and productive forum for dealing with future significant changes that may be warranted.

As discussed in the sections above, there is a significant informational asymmetry in place in the state that is hindering the ability of parties to agree upon basic facts and then collectively work toward reasonable solutions. Due to this lack of transparency, the 2017 Working Groups were not able to come up with any breakthroughs that are likely to significantly improve the process going forward.

IREC appreciates the Commission's commitment to this effort and the opportunity to share our independent, national perspective and multi-state interconnection experience and expertise.

**Q. Does this conclude your testimony?**

A. Yes.

CHAIRMAN FINLEY: Her rebuttal testimony of 32 pages of January 8, 2019 is copied into the record as though given orally from the stand, and her one rebuttal exhibit is marked for identification as premarked in the filing.

MS. BEATON: Thank you.

(Whereupon, the prefiled rebuttal testimony of Sara Baldwin Auck was copied into the record as if given orally from the stand.)

(Whereupon, Exhibit SBA-Rebuttal-1 was identified as premarked.)

## I. Introduction

**Q. Please state your name, title, employment, and business address.**

A. My name is Sara Baldwin Auck. I am the Regulatory Program Director for the Interstate Renewable Energy Council, Inc. ("IREC"). IREC's business address is P.O. Box 1156, Latham, NY 12110-1156. IREC operates as a virtual organization with employees in numerous states. I reside and work remotely in Salt Lake City, Utah.

**Q. Are you the same Sara Baldwin Auck who submitted direct testimony in this proceeding?**

A. Yes.

**Q. For whom are you testifying?**

A. I am testifying on behalf of the Interstate Renewable Energy Council, Inc. ("IREC").

**Q. Are you sponsoring any exhibits in support of your rebuttal testimony?**

A. Yes, I am sponsoring **Exhibit SBA-Rebuttal-1**, excerpts from IREC's Proposed Redline to North Carolina's Interconnection Procedures. A formatting error in **Exhibit SBA-Direct-2** prevented the comments in that version of the redline from being visible. **Exhibit SBA-Rebuttal-1** is an excerpt of the same redline that includes only the pages with comments and the page with one change: the definition of "Line section" is revised, as explained in the rebuttal testimony of

IREC Witness Lydic.[1] Described another way, the contents of the redline in both exhibits are the same with two exceptions. In the excerpts provided as **Exhibit SBA-Rebuttal-1** the comments are visible and the definition of "Line section" is revised.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my testimony is to respond to the direct testimony of other parties in this proceeding. I do not respond to every point made by every witness in this proceeding. Instead, my rebuttal testimony focuses on those points where I disagree with other witnesses, or where I believe another witness has misunderstood or misrepresented IREC's proposals or positions.

**Q. Please summarize the key points of your rebuttal testimony.**

A. IREC believes that the Commission's efforts in this proceeding should focus on ensuring that only projects with a reasonably likelihood to cause safety or reliability impacts are placed in the costly and timely Supplemental Review and full study processes. The purpose of Fast Track is to avoid unnecessary study of projects that do not pose a reasonable risk of causing safety or reliability impacts. The entire point of the Fast Track process is undermined when nearly every eligible project fails Fast Track, and it is later revealed that virtually none of those projects would have the kinds of impacts that Fast Track is intended to screen for. Therefore, IREC encourages the Commission to prioritize our recommendations

[1] Rebuttal Testimony of Brian M. Lydic on behalf of IREC ("Lydic Rebuttal Testimony") at 19.

regarding effective application of the Fast Track screens as set forth in the direct and rebuttal testimony of IREC Witness Lydic.

Next, Duke agrees that North Carolina's study process is unsustainable. To address this problem, Duke proposes to investigate switching from a serial study process to a cluster study process. IREC is not opposed to a well thought out cluster study process; however we believe that a useful cluster study process must be developed and vetted through a collaborative stakeholder process that ensures that projects are treated fairly and in a non-discriminatory manner. Ultimately, a cluster study program will take substantial time and effort to develop and implement. The North Carolina Interconnection Procedures ("NCIP") have inefficiencies that demand attention now, and IREC presents options that address this immediate need.

IREC proposes targeted revisions to the Fast Track and Supplemental Review processes, along with transparency and accountability measures, that we believe will immediately lower the time and costs associated with interconnecting relatively small projects in North Carolina. For example, numerous interconnection customers with projects that pass rigorous technical screens will avoid getting caught up in the queue or being subjected to unnecessary additional study processes, *e.g.*, Supplemental Review, cluster studies, or serial studies. These steps will enable Duke to focus staff resources on the projects in the backlogged study queue while also providing a better interconnection experience for North Carolina customers.

When considering long-term solutions, IREC believes it is appropriate at this time for the utilities to invest in developing Hosting Capacity Analyses ("HCA"). Like the Fast Track proposals presented by IREC, the publication of hosting capacity maps can help interconnection customers propose projects that will avoid the lengthy study process and help those that will still need to undergo study to better predict and plan for how the interconnection process will proceed.

The NCIP's alternative dispute resolution provisions should include a neutral party and reasonable timelines. Duke's proposal fails on both fronts. IREC believes that establishing an Interconnection Ombudsperson, as described in my direct testimony, is the best alternative dispute resolution proposal before the Commission because an Ombudsperson would have dedicated staff and resources to monitor and help resolve interconnection issues.

While it is important that the NCIP addresses disputes in a structured manner, it is more important to structure the NCIP to result in fewer disputes. Defining screens for each level of review, adding technical details regarding screen implementation, and publishing hosting capacity maps, among other options recommended by IREC in this docket, will prevent many more projects from needing costly and time-consuming studies that are the subject of most disputes.

IREC supports robust transparency measures and independent oversight of changes in administration of the NCIP. Instead of allowing utilities to run a technical standards review group, as proposed by the utilities and Public Staff, the

Commission should convene a technical working group that is open to all stakeholders and administered in a neutral manner. IREC is concerned that without Commission oversight of the technical working group's agendas, utilities will not allow other perspectives a fair opportunity to present their ideas.

## II. IREC's Perspective in This Proceeding.

**Q. What interests are represented in this proceeding?**

A. In this proceeding, various parties represent different interests. The investor-owned utilities' employees represent the interests of their shareholders. Public Staff represents "the using and consuming public," but not the "general public."[2] In addition to representing only "the using and consuming public" Public Staff's advocacy on behalf of that segment of the population is narrowly limited to their interest in reliable service at reasonable rates.[3] The North Carolina Pork Council represents the interests of its members in developing a particular type of renewable energy. The North Carolina Clean Energy Business Alliance ("NCCEBA") and North Carolina Sustainable Energy Association ("NCSEA") represent local renewable energy developers.

**Q. Whose interests does IREC represent in this proceeding?**

A. In this docket, IREC uniquely represents the interests of North Carolina consumers who seek access to a wide range of affordable and sustainable distributed energy resources.

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[2] Testimony of Jay Lucas on behalf of Public Staff ("Lucas Testimony") at 5:12-6:21.

[3] Lucas Testimony at 5:12-6:21.

IREC does not represent the distributed energy resources development community, and instead speaks for consumers' interest in creating a fair and level playing field among all entities pursuing new renewable energy projects. It is important to recognize that while the interests of the solar development community are generally aligned with the interests of consumers seeking access to affordable clean energy, the industry associations are not speaking on behalf of consumers.

Similarly, Public Staff does not perceive its mandate to include representing consumers' interest in accessing affordable and sustainable clean energy. As described in the direct testimony of Witness Lucas, Public Staff only represents the interests of utility customers in reliable service and affordable rates.[4] While the consumers IREC represents also share those interests, we also represent the interest of consumers who may have a broader perspective and are also interested in having access to affordable and sustainable clean energy.

IREC also draws from its participation in numerous state-level proceedings, bringing national expertise in interconnection best practices. IREC is interested in supporting a fair and efficient interconnection process in North Carolina that implements effectively the state's renewable energy policies.

**Q. Do you agree with Public Staff's characterization that developers of distributed generation ("DG") are not the using and consuming public?**

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[4] Lucas Testimony at 5:12-6:21.

A. Not entirely. For Public Staff, Witness Lucas argues that "developers of DG are not the using and consuming public, because they are primarily not a consumer of utility service, at least not in the same way as other consumers represented by the Public Staff."[5] When speaking about developers who are installing wholesale renewable energy facilities, I can agree with Witness Lucas that these developers are not the using and consuming public. However it is important to recognize that these are not the only types of interconnection customers that could be impacted by the outcomes in this proceeding.

For example, homeowners and businesses that install distributed energy resources behind their meter, either for net metering, stand-by or non-exporting service, remain consumers of utility service. In the case of these systems sized to partially offset the customer's use or to maintain power during a system outage, the customer is still a purchaser of electricity from the utility. In all other respects, that customer is dependent on the utility to supply her energy, similar to all other customers. Owners of residential or commercial systems are similarly situated to other residential or commercial customers, and utilities should not discriminate against owners of distributed energy resources. Most utility customers who seek to install on-site renewable energy avail themselves of the services of developers, but this does not change the fact that these utility customers are directly impacted by the efficiency and fairness of the interconnection process.

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[5] Lucas Testimony at 6:15-18.

## III. Fast Track

**Q. Does IREC believe that North Carolina's Fast Track process is working effectively?**

A. No, IREC does not believe that the Fast Track process is working effectively. The purpose of the Fast Track process is to allow projects that do not require lengthy study to interconnect expeditiously. As discussed in the direct testimony of Witness Lydic,[6] IREC believes that Duke is applying the Fast Track screens in an unjustifiably restrictive way that results in unnecessary Supplemental Review or lengthy studies before interconnecting projects. IREC points to the unreasonably high 98 percent failure rate as an indication that the Fast Track process is not working effectively. Duke's witnesses imply that the high penetration of DG in North Carolina is to blame for its interconnection challenges including the fact that most projects fail Fast Track review on Screen 3.2.1.2 (the 15% of peak load screen).[7] However, IREC Witness Lydic explained in his direct testimony that the same high failure rate is seen in Duke's territory in South Carolina; he concludes that this indicates that high penetration is not the source of the failure.[8] In addition, Witness Lydic's rebuttal testimony explains that it

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[6] Direct Testimony of Brian M. Lydic on behalf of IREC ("Lydic Testimony") at 5-16.

[7] Direct Testimony of Gary R. Freeman on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Freeman Testimony") at 14-17; Direct Testimony of John W. Gajda on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Gajda Testimony") at 26:1-18.

[8] Lydic Testimony at 7-9.

continues to be quite rare for 20-100 kW projects to fail the 15% of peak load screen in other states with the most active distributed generation markets.[9]

The point of Fast Track is to avoid unnecessary study of projects that are unlikely to have safety and reliability impacts. Thus, the goal of Fast Track should be to screen out only those projects that create a risk of such impacts and send them to Supplemental Review or further study. However, as IREC's Witness Lydic explained, Duke's narrow application of the 15% of peak load screen has resulted in the vast majority of Fast Track eligible projects being subject to unnecessary, further review. And the fact that these projects nearly always pass Supplemental Review is one indication that they would be unlikely to result in safety and reliability impacts, and the further review was unnecessary. Of course, Fast Track is intended to be conservative, and there will always be projects that would not have impacts that nonetheless fail Fast Track. But the entire point of the process is undermined when nearly every eligible project fails Fast Track even though Supplemental Review does not reveal significant system impacts for virtually any of them; this suggests the initial screens may not be serving any function.

**Q. Please respond to Duke's proposal to allow the utility and customer to mutually agree to study a project under Fast Track.**

A. Duke proposes "to allow a utility and Interconnection Customer to mutually agree that an Interconnection Request can be studied pursuant to the Section 3

[9] Lydic Rebuttal Testimony at 10-11.

process even if the Interconnection Customer otherwise would not be eligible for Fast Track."[10] IREC supports this proposal as a reasonable modification that will speed up the interconnection process for some customers.

IREC does not believe, however, that this change obviates the need to modify the Fast Track eligibility limits for DERs connecting to low voltage lines. IREC's proposal provides Fast Track eligibility for all projects that meet the *de facto* national standard.[11] By contrast, Duke's proposal only applies to specific projects that a utility approves of. It is not a replacement for updating the Fast Track eligibility table.

**Q. Moving on to another issue, does Duke propose to modify the information that customers receive with Fast Track screen results?**

A. Yes. Currently, NCIP Section 3.3 requires Duke to provide a customer "copies of all data and analyses underlying its conclusion" within five business days of the customer's project failing Fast Track. Duke proposes to remove the word "all" from the preceding quote, and to only provide this information upon a customer's request.[12]

**Q. How does IREC respond to this proposal?**

A. This concept may be reasonable, but without implementation details included in the NCIP, IREC cannot support it.

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[10] Gajda Testimony at 20:22-21:2.

[11] Direct Testimony of Sara Baldwin Auck on behalf of IREC ("Auck Testimony") at 17-22.

[12] Gajda Testimony at 21:13-23; **Gajda Exhibit No. 1** at 26.

I am particularly concerned that Duke's proposal appears to remove the required timeline for the utility to provide the data and analysis underlying its conclusion that a project failed a Fast Track screen. The Commission should not relieve a utility of its obligations to show its work within five days of a screen failure, provided the customer requested this information in advance. If the Commission choses to implement this proposal, IREC recommends the following changes. The NCIP should:

1. clearly state the five day timeline continues to apply;
2. allow an interconnection customer to request this data and analysis at any time; and
3. revise the Interconnection Request Application Form in Attachment 2 to ask if the customer wants to receive this data and analysis in the event its project fails Fast Track.

## IV. Supplemental Review

**Q. Turning to Supplemental Review, please address Duke's proposed changes to the Supplemental Review process.**

A. Duke proposes to allow interconnection customers using Fast Track "the option to move directly to Supplemental Review without the need to request an additional deposit after a customer options communication, if an Interconnection Customer so selected ahead of time in the Interconnection Request."[13]

[13] Gajda Testimony at 20:11-16.

IREC supports Duke's proposal as a reasonable modification to the NCIP. However, this modification fails to address the underlying cause of delays in North Carolina's interconnection process. IREC believes that the Commission's efforts in this proceeding should focus on ensuring that only projects with a reasonable likelihood to cause safety or reliability impacts are placed in the costly and timely Supplemental Review and full study processes. While Duke's proposed modification will allow projects to move more quickly to Supplemental Review when needed, it does not address the underlying cause of the unjustifiably high Fast Track failure rate. Therefore, IREC encourages the Commission to prioritize IREC's recommendations regarding effective application of the Fast Track screens as set forth in the direct and rebuttal testimony of IREC's Witness Lydic.[14]

**Q. What is Duke's position regarding IREC's proposal to define the Supplemental Review screens in the NCIP, and what is your response?**

A. Duke states that the additional screens would impose additional administrative burdens on utilities, and further clog the queue.[15] Duke provides no quantification of the additional burden using defined screens would place on the utility. Duke already uses internally-defined screens, and its engineers document the results of that screening.[16] As IREC's Witness Lydic explained in his direct

[14] Lydic Testimony at 5-16.

[15] Gajda Testimony at 34:21-35:15.

[16] *See* **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-3c, 1-3e, 1-3f, and 1-3g; **Exhibit SBA-Direct-8**, Duke's Response to IREC Data Request 1-4g.

testimony, Duke could continue to use these screens within the framework of the defined—but flexible—screens that IREC proposes.[17] Defining the screens would simply provide more transparency to developers, who would be able to understand what Supplemental Review entails and gauge whether a project is likely to pass it. Notably, Duke provides no persuasive evidence for its claim that the use of defined screens will further clog the queue. It is thus reasonable for the Commission to adopt a more clearly defined process that aligns with national best practices and has proven to be a useful tool for streamlining interconnection in many other states. At a minimum, the Commission should require Duke to publish in the NCIP the screens that it currently uses in Supplemental Review, to provide necessary transparency into the technical standards which projects must meet to pass Supplemental Review.

Duke also points out that the Commission declined to adopt defined supplemental review screens in 2015.[18]

**Q. Is this characterization of the Commission's 2015 decision complete?**

A. No. Witness Gajda's direct testimony does not describe the rationale for the Commission's 2015 decision. When addressing IREC's 2015 proposal to place defined screens in the NCIP, the Commission said:

> Further, the Commission is not convinced that an enhanced Supplemental Review Process at this time would provide sufficient efficiency to warrant changing the current process which allows for supplemental review. The Commission finds that the Utilities' resources should not be used on performing mini-studies, under an expanded Supplemental Review Process,

[17] Lydic Testimony at 22:10-13.

[18] Gajda Testimony at 35:15-18.

on projects in which 60 to 80 percent will most likely still need to proceed to the Section 4 Full Study Process.

However, the Commission is of the opinion that once the queue is unclogged that a more robust Supplemental Review Process might very well assist in maintaining an efficient queue. Therefore, the Commission orders the parties to collaborate to create a workable Supplemental Review Process that adds some structure to the currently flexible and undefined Supplemental Review Process, but that is not as structured as IREC's proposal in which the Utilities are forced to perform inefficient studies for projects that most likely will not pass, diverting resources that can be better spent performing full studies. The parties shall provide the Commission with its results when the Commission reviews this matter in approximately two and one-half years after the ordered stakeholder meeting process.[19]

**Q. Does the Commission's rationale for its 2015 decision hold today?**

A. No. The Commission's decision is placed in the context of the Commission's impression that an estimated 60 to 80 percent of projects will fail Supplemental Review and require full study. With the benefit of historical data from Duke today, we know that the actual fail rate for supplemental review is 1.1 percent in DEC's service territory, and 3.2 percent in DEP's service territory.[20] In short, nearly all projects pass Supplemental Review, demonstrating the usefulness of the process. IREC's proposal is simply that the process be made more transparent.

Moreover, the Commission explicitly requested that the parties revisit this issue in today's proceedings. Now, over three years after the Commission's 2015 decision, the time is ripe to reevaluate this issue on its merits using the most recent

[19] Order Approving Revised Interconnection Standard, N.C.U.C. Docket No. E-100, Sub 101, at 17-18 (May 15, 2015) ("2015 Order").

[20] **Exhibit SBA-Direct-8,** Duke's Response to IREC Data Request 1-3c.

and accurate data available. Witness Lydic's direct and rebuttal testimony addresses IREC's position on the merits of using a defined screen for Supplemental Review.

**Q. Finally, how does IREC respond to Duke's proposal to allow Facilities Studies under Supplemental Review in Section 3.4.1.3?**

A. Duke's proposal appears reasonable. IREC recommends that each paragraph receive its own subsection number, mirroring how these issues are addressed in Section 2. Duke's additional paragraph should be numbered 3.4.1.4, and the final paragraph of this section numbered 3.4.1.5.

## V. Cluster Studies and Hosting Capacity Analysis

**Q. How does Duke characterize the North Carolina study process under today's procedures?**

A. Duke states that the current study process "is not sustainable as it would likely require decades to . . . connect the 14,000 MW of renewable generating facilities that are in the current . . . queues."[21] IREC agrees that the current situation is not sustainable, and believes that the Commission should revise the NCIP to include fair processes that would more effectively manage utility interconnection queues while maintaining a fair and non-discriminatory interconnection process that does not impair the competitive nature of the renewable energy market in the state.

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[21] Freeman Testimony at 30:13-16.

**Q. What does Duke propose to do in order to address its unsustainable interconnection queue?**

A. Duke proposes to investigate switching from a serial study process to a group or cluster study process.[22] Duke states that it held a stakeholder meeting in June to discuss the use of a cluster study process in the NCIP. IREC was not invited to this stakeholder meeting.

**Q. What is IREC's position regarding cluster studies?**

A. IREC is not opposed to consideration of a well thought out cluster study process. We believe that a useful cluster study must be developed and vetted through a collaborative stakeholder process that ensures projects are treated fairly and in a non-discriminatory manner. IREC's experience is that cluster studies can be useful in some circumstances, but also raise a host of unique issues and can actually exacerbate queue problems and disputes, if not well designed. A cluster study process can also lead to disputes once implemented. Based on our experience working in states that have developed group and cluster studies, IREC recommends, at a minimum, that the proposed cluster study process should (1) define timelines for each step of the process, (2) define what happens if projects drop out of the study group, (3) explain how costs will be allocated between projects in a group, and (4) explain how groups would be formed. Duke's earlier

[22] Freeman Testimony at 30:12-32:12. IREC uses the terms group study process and cluster study process interchangeably in this testimony. Duke uses the term cluster study in its testimony. In our experience, the term group study is generally used for distribution system interconnections, while the term cluster study is generally used for transmission system interconnections.

cluster study proposal has elements that could be considered discriminatory, therefore IREC recommends that Commission approach this proposal with caution.[23]

IREC has engaged on the issue of cluster formation in other states and at FERC, and we understand that development of a cluster study process is tricky, but that simply means it needs to be well thought out. We note that, in the past year, Massachusetts considered updates to that state's distribution group study process.[24] There, the utilities requested changes to the state's existing group study process to address problems that arose from implementing the first iteration, including problems related to the need for multiple study iterations due to project changes, and issues arising from coordinating group members and managing delays.[25] The Massachusetts utilities also requested revisions to clarify the group study process, including better defining timelines and defaults.[26] It is worth ensuring that any cluster study process adopted in North Carolina be informed by lessons learned in other states, and the Commission should require a robust stakeholder process to review and develop a durable cluster study process. IREC is particularly interested in ensuring that small projects that can be efficiently

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[23] IREC Reply comments at 27-31 (March 12, 2018).

[24] *See* Mass. Dept. of Public Utilities, Docket No. D.P.U. 17-164.

[25] *See* Joint Direct Testimony of John J. Bonazoli, Timothy R. Roughan, Brett A. Jacobson, Mass. Dept. of Public Utilities, Docket No. D.P.U 17-164, at 7:1-10 (Oct. 20, 2017).

[26] *Id.* at 9:15-22 – 10:1-3.

reviewed through a technical screening process do not get caught up in a lengthy cluster study process.

**Q. What are IREC's proposals to address Duke's unsustainable interconnection queue?**

A. As described in my initial testimony, IREC believes that our targeted revisions to the Fast Track and Supplemental Review processes, along with our proposed transparency and accountability measures, will lower the time and costs associated with interconnecting relatively small projects in North Carolina. These steps will enable Duke to focus staff resources on the projects in the backlogged study queue while also providing a better interconnection experience for North Carolina customers. If the Commission implements IREC's proposed changes to the Fast Track process in this revision to the NCIP, numerous interconnection customers will avoid unnecessary Supplemental Review altogether. While using a cluster study process may be a reasonable approach in the long term, it will take time to implement, and thus will not unclog the queue in the short term. By contrast, IREC's Fast Track and Supplemental Review proposals prevent projects that pass rigorous technical screens from getting caught up in unnecessary additional review and allow utility customers installing systems behind the meter to have a positive, low-cost and efficient interconnection experience.

When considering long-term solutions, IREC believes it is appropriate at this time for utilities to develop Hosting Capacity Analyses that can help customers better site their projects and predict the outcomes of the interconnection process. Like the Fast Track proposals presented by IREC, the publication of hosting capacity maps can help interconnection customers propose projects that will avoid the lengthy study process and expensive upgrades because they will be sited where there is capacity for them, and will be better designed for the intended location. Publication of hosting capacity maps also helps customers with projects requiring study to better predict how the interconnection process will proceed. For example a good hosting capacity analysis can identify whether upgrades that may be required would be relatively minor or involve major construction. While IREC does not oppose Duke's proposal to investigate a cluster study process, we believe this should not be in lieu of or a replacement for other approaches that help customers select projects which avoid lengthy studies altogether and instead benefit the grid. Hosting capacity maps provide customers the information necessary to select locations for such projects *in advance* of submitting an interconnection application, while a cluster study process will only provide a customer this information after he has spent time and money designing, proposing, and requesting an interconnection.

**Q. Does Public Staff respond to IREC's proposal that utilities develop HCA?**

A. Yes, Public Staff agrees with IREC that HCA "could reduce the number of interconnection requests that would later fail one or more of the NCIP screens, which would assist in unclogging the queue."[27] Public Staff proposes that the

[27] Lucas Testimony at 24:1-3.

Commission direct Duke to provide a hosting capacity map that focuses on Duke's transmission system.[28] IREC, by contrast, suggests that Duke focus its analysis and mapping on its distribution system.[29]

**Q. Why do IREC and Public Staff recommend developing hosting capacity maps for different parts of Duke's system?**

A. As stated in my direct testimony, IREC believes that North Carolina will see an increase in the number of Fast Track-eligible projects interconnecting to the distribution system.[30] The utilities agree that they will see an increase in the volume of small scale solar interconnections.[31] In Witness Riggins' direct testimony, Duke presents evidence of the fast growth of small projects in 2017 and 2018, and projects that this trend will continue.[32] Public Staff, by contrast, states that "the recent trend in North Carolina has been the development of larger, transmission-connected projects."[33] As I explained above, it is reasonable to expect that small projects, which are likely to connect to the distribution system, will comprise the vast majority of the interconnection requests that Duke receives

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[28] Lucas Testimony at 23:5-24:19.

[29] Auck Testimony at 36-43.

[30] Auck Testimony at 11:9-13:3.

[31] Joint Reply Comments of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Dominion Energy North Carolina, N.C.U.C. Docket No. E-100, Sub 101, at 12 (March 12, 2018).

[32] Direct Testimony of Jeffery W. Riggins on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Riggins Testimony") at 24:4-9 (Figure 2).

[33] Lucas Testimony at 23:5 (citing Transcript of Oral Argument Hearing held on Monday, September 24, 2018, Raleigh, Volume 1, Brett Breitschwerdt at 11).

in the coming years. Thus, IREC recommends that the Commission direct Duke to prepare an HCA of its distribution system to facilitate the smart siting and efficient interconnection of these projects. IREC agrees with staff that there will also be more activity on the transmission system, but does not believe this negates the need for a distribution system hosting capacity analysis.

**Q. What is your opinion of Public Staff's proposal that Duke prepare a hosting capacity analysis of the transmission system?**

A. IREC's work on hosting capacity analyses has principally focused on the development of distribution system analyses. We have not seen or evaluated transmission system hosting capacity analyses. Due to the inherent differences between how distribution and transmission systems are designed and operated I do not currently have an opinion on whether it is feasible to develop an adequate hosting capacity analysis of the transmission system. IREC thus takes no position on whether Duke should be required to prepare a transmission level hosting capacity analysis. We do, however, continue to support the development of a hosting capacity analysis for the distribution system.

**Q. Are HCA useful for purposes beyond the selection of locations for generation resources?**

A. Yes. As described in **Exhibit SBA-Direct-6,** IREC's report on HCA, there are multiple use cases for this analysis. Interconnection is one potential use, but it is not the only one. HCA could also be used in the distribution system planning process. The analysis could provide hosting capacities for different locations around the distribution system, forecast load growth and DER growth across the distribution system, then use these inputs to proactively pursue grid upgrades, including non-wires alternatives, to meet identified grid needs. IREC's report also identifies additional potential uses.

These other benefits all flow from the fact that developing an HCA provides the utility, commission, and stakeholders more visibility into the use of the distribution system than was available before the analysis was completed. This increased visibility is useful to all customers, and is an example of grid modernization that IREC believes utilities should move towards. Following increased visibility, the logical next step is using available data for distribution grid planning and optimization. In order to realize these benefits, it is important for utilities and the Commission to carefully consider which methodology of HCA it chooses to pursue.

**Q. What is Public Staff's proposal regarding cost allocation of utilities' HCA, and how does IREC respond to this proposal?**

A. Public Staff proposes that the costs of developing a hosting capacity analysis "be recovered from DG developers through the fees and charges collected from those customers."[34] IREC does not believe that Public Staff's proposal is appropriate for several reasons.

First, as I explained above there are use cases for HCA that provide a myriad of benefits to all customers. Providing the Commission, utility

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[34] Lucas Testimony at 25:1-7.

management, and stakeholders greater visibility into the operation of the distribution system is broad benefit that is not distinctly attributable to any class of customers connected to the distribution system. By providing increased visibility into available hosting capacity, and associated constraints, IREC believes it is likely that this will increase the opportunities to utilize customer sited DERs to mitigate, defer or even avoid traditional utility investments. These savings would be directly realized by ratepayers. Therefore, it is appropriate to collect these costs from all customers connected to the distribution system.

Second, collecting these costs directly from a specific segment of customers requires developing a method to fairly allocate these costs among those customers. Developing such a cost allocation method could prove difficult. For example, should a customer significantly increasing her load by adding square footage to her home, adding new appliances, or charging an electric vehicle contribute to the costs of this analysis? Is it appropriate for a customer that interconnected her DER one, five, or ten years ago to contribute towards the study? If so, should these customers contribute the same amount as customers submitting an interconnection request today? What proportion of the costs should customers requesting to interconnect a small inverter-based project pay, as opposed to mid-sized and utility-scale projects?

IREC is not aware of any other state that asks interconnection customers to pay the costs of an HCA that maps the utility's entire distribution system. IREC recommends that the Commission avoid going down a path that ends in the questions raised above (and may not result in an efficient, fair or sustainable way to allocate costs after much time and energy is spent determining the allocation). Instead, the Commission should acknowledge the broad benefit of performing an HCA on the distribution system and allocate its costs the same way as utilities allocate the costs of other distribution system planning tools.

## VI. Dispute Resolution

**Q. Do other parties propose modifications to the dispute resolution process?**

A. Yes. Duke proposes to modify the current dispute resolution process by adding strict timelines with severe consequences for interconnection customers.[35] Public Staff proposes to allow the use of a dispute resolution service, *e.g.*, mediation, settlement judge, early neutral evaluation, or technical expert, and includes reasonable timelines with severe consequences for customers.[36]

**Q. Which proposals in this case include use of a neutral party?**

A. Both Public Staff and IREC propose the use of neutral party in alternative dispute resolution. Public Staff's proposal allows parties to use a dispute resolution service, while IREC's proposal provides for an Interconnection Ombudsperson and the use of an outside mediator. The current NCIP and Duke's proposal do not call for the use of a neutral party, and instead allow Public Staff as the only option for mediation. Public Staff acknowledges that it is not a neutral

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[35] **Gajada Exhibit No. 1** at 34-35.

[36] **Lucas Exhibit No. 1.**

party in these disputes.[37] IREC believes that use of a neutral third party would help facilitate an unbiased and impartial administration of the NCIP.

**Q. How do you respond to the timelines in Duke and Public Staff's dispute resolution proposals?**

A. The Commission should reject Duke's dispute resolution proposal because it does not put all the facts before a mutually-respected neutral party and includes unreasonably strict timelines. As explained below, IREC is not opposed to adding timelines to the dispute resolution process, however IREC opposes Duke's proposal because the strictly written timelines therein are unreasonable.

First, Duke's proposal starts tolling the timelines immediately upon issuance of the notice of dispute and does not provide an opportunity for the parties to mutually agree to extend the timeline at any point in the process.[38] By contrast, the proposals of Public Staff and IREC allow the parties to extend the timelines during the dispute resolution process.[39]

Second, Duke's timeline concludes the dispute resolution process facilitated by Public Staff twenty business days after the first meeting in all circumstances.[40] In fact, Duke's proposal requires that an interconnection customer file a formal complaint with the Commission twenty business days after the first meeting with Public Staff or the customer loses her position in the

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[37] Lucas Testimony at 37:22 - 38:8.

[38] **Gajada Exhibit No. 1** at 34-35.

[39] **Lucas Exhibit No. 1** § § 6.2.3-6.2.4; **Exhibit SBA-Direct-2** § 6.2.5.

[40] **Gajada Exhibit No. 1** § 6.2.5.

interconnection queue.[41] This strict timeline means that the interconnection customer must hire an attorney and prepare her formal complaint in the same twenty business days when she is explaining her position to Public Staff and attempting to continue negotiations with the utility. I do not believe that this is a reasonable practice because it may not provide enough time for the alternative dispute resolution process to run its course, and it splits the interconnection customer's bandwidth and resources. In this short time period, the interconnection customer would spend a significant amount of time preparing the formal complaint instead of focusing all of her energy on an amicable resolution of the dispute with the assistance of Public Staff. It also simply narrows the time available for parties who are making progress towards resolution to complete their negotiations.

If the Commission chooses to add timelines to the dispute resolution process, IREC recommends that it adopt Public Staff's proposed timelines. Public Staff's proposal does not require that the interconnection customer prepare a formal complaint while the alternative dispute resolution process is ongoing. Instead, the process is allowed to run its course and after it is complete the interconnection customer is given ten business days to show intent to file a formal complaint, followed by thirty business days to prepare the formal complaint.[42] By providing a distinct forty business day time period for the interconnection

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[41] **Gajada Exhibit No. 1** § 6.2.5.

[42] **Lucas Exhibit No. 1** § 6.2.6.

customer to prepare her formal complaint, Public Staff's proposal allows the customer to focus her energy on the alternative dispute resolution process while that process is ongoing. IREC believes that this will result in more productive negotiations between the parties, because the customer will focus exclusively on an amicable resolution of the dispute during that time period. IREC believes that Public Staff's timeline for the conclusion of the dispute resolution process is a reasonable way to ensure that the process progresses at an orderly pace.

**Q. Is IREC changing its positions regarding dispute resolution?**

A. No. As I said in earlier testimony, IREC is open other reasonable proposals regarding dispute resolution, including Public Staff's proposal. IREC believes that establishing an Interconnection Ombudsperson, as described in my direct testimony, is the best alternative dispute resolution proposal before the Commission because an Ombudsperson would have staff and resources dedicated to monitoring interconnection issues.[43] The Ombudsperson would also have the benefit of seeing multiple different disputes and be able to identify consistent issues for the Commission that may warrant broader resolution. Finally, IREC believes that using its proposed timelines, including a requirement that the non-disputing party provide "all relevant regulatory and/or technical details and analysis regarding" the dispute within ten Business Days of the date on the notice of dispute, will best promote the efficient resolution of disputes.[44]

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[43] Auck Testimony at 45-48.

[44] **Exhibit SBA-Direct-2** § 6.2.

**Q. Do you have any other observations regarding interconnection disputes?**

A. While it is important that the NCIP addresses disputes in a structured manner, it is more important to structure the NCIP to result in fewer disputes. Defining screens for each level of review and adding technical details regarding screen implementation and publishing hosting capacity maps, among other options recommended by IREC in this docket, will prevent many more projects from needing costly and time-consuming studies that are the subject of most disputes.

**Q. Does Duke propose to add any other timeline requirements for interconnection customers?**

A. Yes. Duke proposes to require interconnection customers to respond to requests for additional information and action within a reasonable timeframe. If the customer does not respond in that undefined timeframe, a utility could then provide written notice with a ten business day deadline.[45]

**Q. How does IREC respond to this proposal?**

A. As I stated in my direct testimony, IREC supports additional timeline requirements for customers if warranted and equitable. In this case, IREC would support this proposal if it was modified to require the utility, before the establishment of any deadlines, to provide the customer all information necessary to ensure the customer can make an informed decision.

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[45] Riggins Testimony at 23:9-10.

## VII. Technical Working Group and Independent Review

**Q. What are Public Staff's transparency proposals in this proceeding?**

A. Public Staff makes transparency proposals regarding utility modifications to the application of the NCIP, and an independent review of the NCIP. I address each below.

**Q. Please describe Public Staff's proposal regarding modifications to the application of the NCIP.**

A. Public Staff recommends that:

> in the event a new screen, study, or major modification in their application of the NCIP is developed, particularly as it relates to evaluating the technical merits of an application and corresponding interconnection, the Utilities should be required to[46]

file information about the new the new or modification in this docket, publish this information on its website, and present the topic for discussion at the next Technical Standards Review Group.[47]

**Q. How does IREC respond to this proposal?**

A. This proposal represents an incremental step towards increased transparency in the administration of the NCIP. IREC supports the direction that Public Staff is heading with this proposal, but does not believe that it goes far enough in requiring full transparency and independent oversight of the NCIP. Instead, the Commission should convene a technical working group that is open to

[46] Testimony of Tommy C. Williamson, Jr. on Behalf of Public Staff at 24:8-11 ("Williamson Testimony").

[47] Williamson Testimony at 24:11-16.

all stakeholders and administered in a neutral manner. When stakeholders disagree with a technical change proposed by a utility, the Commission should closely examine the change and decide if it is appropriate or not.

There are important benefits to Commission oversight of the technical working group process. When utilities run the technical working group, they can choose who to invite to the meetings and what points of view are allowed time for serious consideration. For example, as discussed by Witness Lydic, IREC was not invited to the Duke-run technical working groups, despite our unique perspective and the depth and breadth of our technical interconnection experience.[48] While IREC may not decide to participate in any working group, we believe this serves as an example of how the process is structured to favor outcomes Duke prefers possibly at the expense of those that are best for the state's consumers. IREC is also concerned that without Commission oversight of the technical working group's agendas, utilities will not allow other perspectives a fair opportunity to present their evidence and ideas.

IREC believes that Commission approval is necessary for any major change to utilities' administration of the Commission's interconnection procedures when a stakeholder contests the change.

**Q. Please provide a description of Public Staff's proposal for an independent review of the NCIP.**

[48] Lydic Rebuttal Testimony at 20.

A. Public Staff Witness Williamson recommends that the Commission order an independent entity to review the NCIP in advance of the next time significant changes are considered.[49] Public Staff recommends that the review take place in 2019, and that the Commission consider changes to the NCIP resulting from the review in 2020.[50]

**Q. Does IREC support an independent review of the NCIP?**

A. Yes, IREC supports Public Staff's proposal. An independent report on inefficiencies in the NCIP, and how utilities' implementation of the NCIP compares to best practices would provide the Commission with useful information. This upcoming review, however, should not result in deferral of changes to the NCIP as a result of today's proceedings. As explained in IREC's testimony there are multiple changes the Commission can make today that will provide immediate and significant improvements and to the interconnection process, and help address the current queue backlog and extant inefficiencies.

Further, IREC supports a regular cadence of updates to the NCIP. Public Staff's proposal for the independent review to occur in 2019, followed by consideration of NCIP revisions in 2020 provides that regular cadence.

**Q. Would any of IREC's proposals facilitate the independent review contemplated by Public Staff?**

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[49] Williamson Testimony at 28:3-30:2.

[50] Williamson Testimony at 30:3-15.

A. Yes. In my direct testimony, I discuss enhanced quarterly reporting requirements.[51] **Exhibit SBA-Direct-4** includes the information IREC proposes to include in the periodic reporting required by the Commission. Significantly, IREC includes reporting of the number of each type of application processed; maximum and average time to process reports, applications, and studies; and the frequency of missed timelines. The quarterly reports proposed by IREC would provide an independent reviewer with detailed information from which to start their investigation before issuing a single data request to utilities. These reports will also facilitate ongoing review of utilities' progress towards resolving these issues by the Commission and stakeholders.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

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[51] Auck Testimony at 32-35.

BY MS. BEATON:

Q Ms. Auck, did you prepare a summary of your direct and rebuttal testimony?

A Yes.

Q And can you please present your summary to the Commission?

A Yes.

Q You can go ahead.

A Thanks. Mr. Chairman and members of the Commission, my name is Sara Baldwin Auck. I am the Vice President for the Interstate Renewable Energy Council's Regulatory Program. My formal -- my former title, as stated in my prefiled direct and rebuttal testimony, was IREC's Regulatory Director. IREC's business mailing address is P.O. Box 1156, Latham, New York, 12110-1156. IREC operates as a virtual organization with employees in numerous states, and I reside and work -- work remotely in Salt Lake City, Utah.

I thank the Commission for the opportunity to participate in this important proceeding. I'm here today to testify on behalf of IREC. In light of North Carolina consumers' demand for interconnection of clean, renewable distributed generation in an efficient and affordable manner and the state's challenges with a heavily burdened interconnection queue, IREC believes North Carolina would benefit greatly from substantial interconnection process reforms and improvements. In my testimony I highlight various mechanisms that the state could adopt to increase transparency and accountability, which are key to ensuring that the state interconnection procedures operate efficiently and effectively. IREC is particularly interested in improving the interconnection process for smaller-scale distributed energy resources, or DERs, for the benefit of today's interconnection customers and in anticipation of future demand for these customer-driven projects. Improving the efficiency of the Utilities' review process for small projects can help free up Utility staff time and resources such that they can focus on those projects that require full study, thereby helping to mitigate and avoid queue backlogs and disputes. Improving the efficiency of the interconnection process will also ensure that North Carolina customers have a fair and efficient path to connect more clean energy to the grid.

As a stakeholder involved in both the 2015 revision of North Carolina's Interconnection Standards and the 2017 Working Group, IREC has observed that interconnection has been a source of contention among

North Carolina customers, developers, and Utilities despite the admirable efforts and collaborative efforts from parties and the Commission. In my testimony and that of IREC's regulatory engineer, Brian Lydic, IREC identifies ways to increase the efficiency of the process by util--- by utilizing well-established screening and grid transparency practices that can focus the Utility's resources on projects that truly require full Section 4 study process, improving the process for all.

Despite the Utilities' efforts since 2015 to clear the substantial backlog of interconnection requests, North Carolina's interconnection queue remains full of projects that are not moving forward in a timely and efficient manner. This has resulted in numerous potentially avoidable disputes between Utilities and interconnection customers, and this proceeding presents an opportunity for the Commission to take a close look at the current procedures and determine what is working, what is not, and ultimately what changes are in the best interest of North Carolina customers.

IREC believes that the Commission's effort -- efforts in this proceeding should focus on ensuring that the Section 3 fast track process works as it should, that only projects with a reasonable likelihood of safety or reliability impacts are sent through the more expensive and time consuming supplemental review and full study processes. The purpose of fast track is to avoid unnecessary study of projects that do not pose a reasonable risk of causing safety or reliability impacts. But the intent of the fast track process is undermined when 98 percent of projects fail fast track, but pass supplemental review, which is the case in Duke's service territory in the Carolinas, revealing that virtually none of those projects would have the kinds of impacts that fast track is intended to screen for. Therefore, IREC encourages the Commission to prioritize our recommendations regarding effective application of the fast track screens as set forth in direct and rebuttal testimony of IREC Witness Lydic.

In addition to modifications to the fast track screening process proposed in Mr. Lydic's testimony, my testimony discusses IREC's support for raising the size limit for fast track eligibility of DERs located on distribution lines that have a voltage of less than -- less than 5 kV from 100 kW to 500 kW, and IREC's proposal that all projects that fail the fast track screens be provided the opportunity to go through a supplemental review process with clearly defined screens.

Next, one of the most impactful changes that the Commission can make to improve the interconnection process is to increase transparency. For example, publishing a distribution system interconnection queue with all of the information that IREC proposes and enhancing quarterly reporting requirements will illuminate why projects are getting stuck in the queue, how often this occurs, and what opportunities there are to improve process efficiencies or revise the procedures going forward.

Another area where the Commission has the opportunity to increase transparency is by requiring the development of hosting capacity maps that describe the current state of the distribution grid. IREC asks the Commission to convene a stakeholder working group to work with the Utilities to inform the development of hosting capacity maps that provide customers the information necessary to propose DERs in areas that are much less likely to require costly upgrades or time consuming system impact studies.

IREC also proposes that the NCIP's dispute resolution provision be improved to provide for a more robust process overseen by a neutral Interconnection Ombudsperson in order to provide for a more streamlined and effective process that is more likely to help disputes going on to a full complaint process before the Commission.

Further, the Commission should consider whether a timeline enforcement mechanism is warranted to ensure the Utilities are meeting their obligations under the procedures.

Finally, IREC suggests the Commission reject proposed large fee increases unless they're supported in the record by data that more clearly demonstrates the associated cost of an activity. This additional cost data will inform whether and to what extent fee increases are warranted, while also ensuring that the Utilities maintain an efficient -- efficient practices and protocols as they process interconnection requests.

In conclusion, I observe that while it is important that the interconnection procedures address disputes in a structured manner, as Duke has requested, it's more important to structure the procedures to result in fewer disputes and to anticipate and prepare for future growth of smaller customer-driven DERs. Clearly defining screens for each level of review, ensuring they're implemented properly, and publishing hosting capacity maps, among other improvements recommended by

IREC, will improve the process for all stakeholders. Thank you.

Q Thank you, Ms. Auck. I have a few questions for you about the recently filed Stipulation between the Duke companies, Dominion, Public Staff, and the Pork Council that was filed on -- last Friday. Have you reviewed the Stipulation that I'm referencing?

A I have skimmed, it, yes.

Q And what is IREC's position regarding Duke's agreement in the recently filed Stipulation to work with EPRI to review its implementation of the fast track and supplemental review processes?

A Well, first, we really appreciate that Duke recognizes that it needs to review and take a closer look at its fast track screens and the implementation of the supplemental review process, particularly the 15 percent of peak load screen.

However, we think this should be done as an independent review overseen by the Commission and/or its staff with the opportunity for IREC and other stakeholders that have been involved in this proceeding to review and comment on any findings of that review. We would certainly be supportive of, as part of that review, there being the opportunity for consultation with EPRI, the National Labs, and/or any other utilities to help inform the process and Duke's review of those screens.

Q Thank you. And do you agree that Duke's implementation of fast track and supplemental review, and specifically the 15 percent of peak load screen, is one of IREC's top issues in this docket?

A Yes. I agree with that.

Q And in testimony today Duke's witness said that after Duke conducts a review of its implementation of fast track and supplemental review with EPRI, it will bring the results back to Duke's TSRG, Technical Standard Review Group, but has IREC been welcome to participate in Duke's TSRG?

A No.

Q And today Duke's Witness Gajda suggested -- actually, yesterday -- excuse me -- Duke's Witness Gajda suggested that this is because the TSRG is only for parties with technical expertise. Does IREC have engineering expertise that it could contribute to the TSRG?

A Yes. IREC's regulatory engineer, Brian Lydic, who submitted testimony in this proceeding, is an engineer and would fit that categorization.

Q Thank you.

MS. BEATON: Mr. Chairman, Ms. Auck is available for cross examination.

CHAIRMAN FINLEY: Public Staff?

MR. DODGE: The Public Staff doesn't have any questions today. Thank you.

CHAIRMAN FINLEY: Companies?

CROSS EXAMINATION BY MR. BREITSCHWERDT:

Q Good afternoon, Ms. Auck. Brett Breitschwerdt on behalf of Duke Energy Carolinas and Duke Energy Progress. How are you?

A I'm doing all right. Thank you. How are you?

Q I'm doing all right. I'd like to start briefly with your resume, if we could, which was Exhibit SBA-1 to your direct testimony.

A Sure.

Q And I don't know, if you want to turn to it, that would be fine. I think you're probably pretty familiar with it. I just have a few questions.

A Sure.

Q Based on the resume it states that from 2004 to 2014 you were the Senior Policy and Regulatory Associate for Utah Clean Energy. Just help the Commission understand what Utah Clean Energy was at that point in time in your career.

A Sure. Utah Clean Energy is a 501(c)(3) nonprofit organization that is active in Utah and also does work in collaboration with other western states on various clean energy issues, energy efficiency, renewable energy, and their mission is to advance clean energy for the state of Utah.

Q All right. So similar to North Carolina Sustainable Energy Association here in this state, based on your knowledge thus far?

A Similar, but I am -- I am much less familiar with the North Carolina Sustainable Energy Association in terms of its mission and its background, having never worked for them.

Q Okay. So let's move to your current position, which congratulations on the promotion.

A Thank you.

Q So you're now the Vice President of the IREC Regulatory Program; is that correct?

A That is correct.

Q And will you describe in a little more detail the strategy of IREC's Regulatory Program?

A Sure. So IREC is a nonprofit, a 501(c)(3) charitable organization, operates to fulfill our mission to expand consumer access to clean energy, and we do that through fact-based policy leadership, quality workforce development, and consumer empowerment. Within IREC's Regulatory Program, my role there is to oversee our active intervention in multiple state proceedings affecting distributed energy resource policies. We also oversee a number of reports and publications and the development of tools and resources to help inform and guide states on these topics that we work on.

Part of our strategy is to work in diverse states and work across multiple states in order to facilitate the information sharing process so that every state does not have to start at ground zero in tackling issues like interconnection standards or hosting capacity analyses or community solar. Much of the work that we do is in collaboration with -- and, actually, I would revise that statement. All the work that we do is in collaboration with local state entities and those that work on the ground in the states in which we're working.

We recognize that our national role makes us somewhat unique in that we are not physically based in any particular state, but we endeavor to collaborate and work very closely with all of the state entities that are at the table in regulatory proceedings.

Q Thank you for that explanation. And it looks like, based on your resume, you prioritize in having this proceeding advancing interconnection for small residential commercial customers and the businesses that provide those interconnection solar services. Energy storage is another area that the Company or -- excuse me -- that IREC has advocated for in this proceeding. So that's kind of the areas of priority, is it fair to say, in terms of advancing the objectives of your organization?

A I think that's a fair assessment. In my last statement I failed to mention that within the regulatory program we're really focused on streamlining and optimizing distributed energy resources on the grid such that we can deploy more of them more quickly, while still maintaining grid safety and reliability, the idea being that consumers are driving a lot of distributed energy resources -- resource investments, and that the rules that govern the grid are really the linchpin to making that process as beneficial and as favorable for those customers as possible. So we really focus on those components.

Q All right. So if you could turn to page 5 of your rebuttal testimony, please.

A Sure. Give me just a second here. Of

rebuttal, you said?

Q Yes, ma'am. And as you're turning there, I -- I think you'll probably be familiar with this, but you generally discuss, starting on page 5, IREC's perspective on this proceeding, and more specifically you discuss your role, and this kind of goes to the strategy that you were just speaking to of IREC compared to other participants in this proceeding, the Utilities, solar advocates such as NCCEBA, NCSEA, and the Public Staff; is that correct?

A That's correct.

Q And starting on line 18 you state that IREC uniquely represents the interests of North Carolina consumers seeking access to renewable energy. Is that a fair statement?

A Yes.

Q All right. And looking to your testimony, then, on page 6, you generally characterize that IREC has asserted itself into this role of representing North Carolina consumers based on your view that the Public Staff is more focused on ensuring reliable service and affordable rates; is that correct?

A That's correct.

Q And it's your understanding, is it not, that the Public Staff is required by North Carolina law to represent consumers in proceedings before the Commission?

A That is my understanding. I am -- I am not a lawyer, so I'm not going to speak to the -- the law, but that is my understanding.

Q Okay. And are you aware the Public Staff actually led the stakeholder process in 2017 for the interconnection review process, along with Advanced Energy?

A I'm aware of that, yes.

Q And while IREC suggests that it's representing the interest of North Carolina consumers, is it accurate that no North Carolina consumers have authorized IREC to represent its interest in this proceeding?

A I would say that we have not gone out and asked North Carolina consumers to -- whether or not we can be here to represent them, but what I would say is that our bylaws as a nonprofit authorize IREC to represent the interest of residential and small commercial customers, and it authorizes us to intervene before governing bodies that are dealing with the rules and regulations that impact those customers, including in North Carolina, but in all states.

Q Okay. So kind of return to the comparison earlier to NCCEBA, NCSEA. IREC is not a trade association. You don't have members in North Carolina who you are specifically advocating on behalf of; is that correct?

A Correct. IREC is not a trade organization and we do not have members.

Q Okay. And so kind of focusing on some of the issues that IREC has raised in this proceeding, no North Carolina consumers have reviewed and approved your testimony representing -- or recommending, excuse me, Utilities invest in hosting capacity maps focused on a distribution system; is that correct?

A I would say that's correct.

Q And the testimony of Duke Witness Riggins suggested that investing in a hosting capacity map would likely cost millions of dollars. Would you agree with that characterization?

A I would agree that that is how Mr. Riggins characterized that. I would disagree with his cost estimate.

Q How much would you suggest that a hosting capacity map for a distribution system of a utility the size of Duke Energy would cost to develop?

A Well, first, I can't speak directly to that, having not gone out and done an RFP for a hosting capacity map or an analysis for Duke, but I can speak to the fact that -- two -- two points I'll make. One, we don't have a lot of publicly available data as to how much hosting capacity maps cost, primarily because those states that have required them or those utilities that are implementing them have not shared that data.

Second to that point, though, is that in California, the state that has been most proactive in leading its development of hosting -- hosting capacity maps, has recently filed some cost data that has shown a range of costs, and the three investor-owned utilities there have filed -- the manner in which they've filed those costs has -- has also really differed across the utilities. Some of them have lumped hosting capacity maps into a much broader category of distribution system planning investments that they are planning to make, thereby making the cost of that distribution map or -- excuse me -- the hosting capacity map potentially very much higher than it would be otherwise, but also hard to discern based on what's in the -- kind of the lump sum figure.

SDG&E, San Diego Gas & Electric, is the one exception to that rule, and they have actually pulled out the hosting capacity map as a line item, and I believe their cost estimate was $400,000.

Q And it's true that the other two utilities said that a hosting capacity map --

COMMISSIONER GRAY: Please speak up or pull the microphone.

MR. BREITSCHWERDT: Yes, sir. Excuse me.

Q And it's also true that the other two California utilities said the hosting capacity map would cost in the range of millions of dollars; is that correct?

A Again, I -- I think it's unfair to characterize their cost estimate as specific to the hosting capacity map itself because they have lumped it into a broader bucket of distribution planning investments that they're planning to make and going to the Commission to get cost recovery for.

Q Okay. Well, let's -- we can move on from the cost and let's talk about the benefits. So whereas IREC's position has been that there would be significant benefits of a hosting capacity map focused on the distribution system, are you aware that Witness Lucas testified that a distribution level hosting capacity map would only provide limited benefits for future projects entering the queue?

A I'm aware that that is Mr. Lucas' position in his testimony, yes.

Q Okay. And are you also aware that IREC and the Public Staff disagree on whether the Commission should impose a timeline enforcement mechanism on the Utilities here in North Carolina?

A I'm sorry. Can you restate your question?

Q Sure. If -- have -- you've reviewed Witness Lucas' testimony, correct?

A I have, yes.

Q And specifically on the issue of a timeline enforcement mechanism he has an opinion on behalf of the Public Staff, correct?

A That is correct.

Q And his opinion on behalf of the Public Staff is that it would not be appropriate to impose a timeline enforcement mechanism on the Utilities in North Carolina; is that correct?

A That is correct, to my recollection.

Q Thank you. And that differs from IREC's advocacy for a timeline enforcement mechanism, correct?

A Yes.

Q Thank you. And -- and are you also familiar with the Public Staff Witness Williamson's testimony, specifically his testimony on the fast track process?

A That one I'm less familiar with, and I have copies of that if you want to refer me to a specific point in that, but...

Q Sure. Well, if you would go to page 13, line 4 through 6, if you would, please.

A Sure. It's going to take me just a second to extract it from my bag here.

Q Not a problem. And specific -- this is specific to IREC's position on the fast track screens and the implementation of the definition of line section.

A Okay. Sorry. You said --

Q Page 15, lines 4 through 6.

A Fifteen. Thank you.

Q Yes, ma'am.

A Sorry. Fifteen, line what?

Q Give me one moment. Sorry. Strike that, if you would. Page 13. Excuse me.

A Okay.

Q Line 4, page 13.

A Okay.

Q And so one of the positions IREC has taken in this proceeding through your testimony and Witness

Lydic's testimony as well is that the Utilities in North Carolina are using an overly conservative approach to the definition of line section in implementing the 15 percent fast track screen; is that correct?

A That is correct, yes.

Q And the implication of that is that is adversely affecting residential customers, small commercial customers that are more likely small commercial to medium commercial customers that are looking to interconnect generating facilities through the Section 3 fast track process; is that correct?

A I'd say that's correct. I would -- I would clarify that it's affecting any and all systems that are below a certain size range that qualified for that fast track under North Carolina's current rules.

Q And that's between 20 kW to 2 MW?

A Correct.

Q And so most residential size projects are probably 10 kW or less; is that fair to say?

A I believe so. I don't know what North Carolina's average size is, but that sounds accurate.

Q All right. So -- and just to kind of close this point out, I mean, if you look at line 4, Witness Williamson on behalf of Public Staff states the Public

Staff's view, in his opinion, is that the Utilities are using -- are reasonable in using a conservative approach that will result a higher degree of grid safety and reliability in terms of implementing the definition of line section and the 15 percent fast track screen. Do you see that?

A I do.

Q And so just -- these are a couple of examples where IREC and the Public Staff --

CHAIRMAN FINLEY: Hold on there, Mr. Breitschwerdt, a minute. It's 5:30. How many more -- how much more time do you have on cross examination?

MR. BREITSCHWERDT: Ten minutes.

CHAIRMAN FINLEY: Ten minutes. Dominion, do you have questions?

MS. KELLS: No questions.

CHAIRMAN FINLEY: Ms. Beaton, have you got -- have you written down some redirect questions there?

MS. BEATON: Not yet.

CHAIRMAN FINLEY: Ms. Auck, what are your travel plans?

THE WITNESS: I am happily available tomorrow as needed. My travel plans are to leave at around -- my flight is at 4:45 p.m., so I would need to leave here around 2:00 to make it on time for my flight, but happy to continue tomorrow morning if that's the preference of the Chairman and the Commission.

CHAIRMAN FINLEY: Well, we will make sure you make your flight, but let's come back tomorrow at 9:30.

MR. BREITSCHWERDT: Thank you, sir.

THE WITNESS: Thank you.

(The hearing was recessed at 5:30 p.m., to be reconvened on January 30, 2019 at 9:30 a.m.)

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STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 101, E-2, Sub 1159, and E-7, Sub 1156, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 13th day of February, 2019.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150

FILED

FEB 13 2019

Clerk's Office

N.C. Utilities Commission