PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, January 28, 2019

TIME: 2:00 p.m. - 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 2

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P R O C E E D I N G S

CHAIRMAN FINLEY: Good afternoon, ladies and gentlemen. Let's come to order and go on the record, please. My name is Edward Finley and with me this afternoon are Commissioners ToNola D. Brown-Bland, James G. Patterson, Jerry C. Dockham, Lyons Gray, Daniel G. Clodfelter, and Charlotte Mitchell.

I now call for hearing Docket Number E-100, Sub 101, In the Matter of Petition for Approval of Generator Interconnection Standards.

On May 15, 2015, in Docket Number E-100, Sub 101, the Commission issued an Order Approving the Revised Interconnection Standard. In Ordering Paragraph 3, the Commission instructed the Public Staff of the North Carolina Utilities Commission to convene a stakeholder process to report such recommendations from the stakeholder group. The Public Staff indicated to the Commission that consensus on changes to the North Carolina Interconnection Procedures could not be reached on all issues.

On August 10, 2018, the Commission issued an Order Scheduling a Hearing on all of the proposed changes to the Interconnection Procedures; (2)

requesting comments; and (3) extending Tranche 1 CPRE RFP solicitation response deadline in Docket Numbers E-100, Sub 101, E-2, Sub 1159 and E-7, Sub 1156, for the purpose of addressing the interim modifications to the Interconnection Standard necessary to accommodate the evaluation and selection of proposals received in response to the Tranche 1 CPRE RFP solicitation. CPRE stands for Competitive Procurement of Renewable Energy.

Oral Argument was held on September 24, 2018 on the interim modifications to the Interconnection Standard necessary to implement the Tranche 1 CPRE RFP solicitation.

Due to scheduling conflicts, the Commission issued an Order on August 30, 2018, Rescheduling the Evidentiary Hearing for all of the proposed changes from October 22, 2018, to this time and date, as well as modifying corresponding filing deadlines.

On August -- on October 5, 2018, the Commission issued an Order Approving Interim Modifications to the North Carolina Interconnection Procedures for Implementation of Tranche 1 of the CPRE RFP.

On November 19, 2018, testimony was filed by

Duke Energy Carolinas, Duke Energy Progress, Dominion Energy North Carolina, the Interstate Renewable Energy Council, the North Carolina Clean Business Alliance -- Energy Business Alliance, the North Carolina Sustainable Energy Association, the North Carolina Pork Council and the Public Staff.

On November 20, 2019, the North Carolina Clean Energy Business Alliance filed the testimony of an additional witness.

On January 4, 2019, rebuttal testimony was filed by most of the parties.

On January 4, 2019, IREC filed a Motion to Bifurcate the Hearing or, in the alternative, a Motion to Continue. Thereafter, on January 14, 2019, IREC filed a subsequent Motion to Excuse Witness Lydic and, if Witness Lydic was not excused to bifurcate the hearing. I think that motion has pretty well been mooted.

On January 8, 2019 (sic), both NCCEBA and the Pork Council filed Motions to Excuse a Witness.

On January 23, 2019, the Commission issued an Order granting all Motions to Excuse the three Witnesses.

On January 25, 2019, DEC and DEP filed an

Agreement and Stipulation of Partial Settlement between those parties - Dominion Energy NC, the NC Pork Council and the Public Staff.

On January 28, 2019, NCSEA filed a Motion for Postponement of Evidentiary Hearing for a period of one week to allow the parties to evaluate the Agreement and Stipulation of Partial Settlement. Also, on January 28, 2019, DEC and DEP filed a Response in Opposition to NCSEA's Motion to Postpone the Hearing.

In compliance with the State Ethics Act, I remind all members of the Commission of their duty to avoid conflicts of interest, and inquire whether any member of the Commission has a known conflict of interest with regard to any matter coming before the Commission this morning -- this afternoon?

(No response)

There appear to be no conflicts, so we will proceed -- so let the record reflect that, and we will proceed to call on the parties to make their appearances known beginning with Duke Energy Progress/Duke Energy Carolinas.

MR. JIRAK: Good afternoon. Jack Jirak from Duke Energy Progress/Duke Energy Carolinas.

MR. BREITSCHWERDT: Brett Breitschwerdt with the Law Firm of McGuireWoods on behalf of Duke Energy Carolinas/Duke Energy Progress.

MS. KELLS: Good afternoon, Mr. Chairman and Commissioners. Andrea Kells with McGuireWoods appearing on behalf of Dominion Energy North Carolina.

MS. KEMERAIT: Good afternoon. I'm Karen Kemerait with the Law Firm of Fox Rothschild in Raleigh. I'm here on behalf of the North Carolina Clean Energy Business Alliance.

MR. LEDFORD: Mr. Chairman, Peter Ledford on behalf of the North Carolina Sustainable Energy Association. With me is my colleague Ben Smith.

MS. BOWEN: Mr. Chairman and Commissioners, Lauren Bowen from the Southern Environmental Law Center here on behalf of the Interstate Renewable Energy Council.

MS. BEATON: Good afternoon, Commissioners. Laura Beaton with the Law Firm of Shute, Mihaly & Weinberger and I'm here on behalf of the Interstate Renewable Energy Council or IREC.

MS. HARROD: Mr. Chairman and Commissioners, Jennifer Harrod, and with me also my colleague Teresa Townsend from the Attorney General's Office. We represent the Using and Consuming Public as well as the State and its Citizens in this matter of public interest.

MR. DODGE: Good afternoon, Commissioners. I'm Tim Dodge with the Public Staff; also appearing with me is Layla Cummings. We represent the Using and Consuming Public.

MR. OLSON: Good afternoon. I'm Kurt Olson here representing the North Carolina Pork Council.

MR. SNOWDEN: Good afternoon. I'm Ben Snowden with the Law Firm of Kilpatrick Townsend representing Cypress Creek Renewables.

CHAIRMAN FINLEY: NCSEA, you have a pending motion. I'll hear from you.

MR. LEDFORD: Yes, Mr. Chairman. Over the weekend we filed a Motion to Postpone the Hearing for a period of one week in response to the late-filed Settlement that only involved a handful of the parties to this proceeding. NCSEA has worked diligently to get through the Settlement and everything that was -- the redline of the Interconnection Agreement that was attached to it, but owing to the Settlement occurring at such a late hour it prejudices our clients to have to move forward with the hearing at this time.

CHAIRMAN FINLEY: Elaborate on that for me, please. How does it prejudice you? Inability to cross examine the witnesses? Are your witnesses unprepared to respond? Help me out there, please.

MR. LEDFORD: Well, there's no opportunity for us to respond to this other than through cross examination. There's no opportunity to present extra evidence, to present extra testimony, so we were asking for an extended period of time to prepare for cross examination.

CHAIRMAN FINLEY: Well, I will be more than happy to let you have your witness respond live from the stand if you would like to do that.

Let me hear from Duke.

MR. JIRAK: I'll just briefly respond and say we don't see that there's been any equitable or legal -- we see no reason to delay the case in this instance. The stipulated modification simply formalized what's already been apparent from hundreds of pages of testimony and pleadings in this case and that is that there's substantial alignment between Dominion, Public Staff and Duke, and for the benefit of the Commission we sought to make that clear to you.

The very, very -- keep in mind there were hundreds of changes in the proposed modifications that have been pending before this Commission for quite some time. We took the step of formalizing the Agreement by agreeing to two changes that the Public Staff had previously entered in the record. We also implemented one change that had been requested by the Pork Council and that was also reflected in their testimony. So there's nothing new substantively here at all. It simply was a formalization of that Agreement so that -- for your benefit and as directed by the Commission we sought to formalize that, put it in front of you to help clarify the issues in this case.

We are more than willing to continue to engage in settlement discussions with other parties. In fact, the one other party that took the initiative to contact us, we have bent over backwards to engage with them, and we've committed to convene in a follow-up with them even after this proceeding to seek to achieve settlement with that party.

So, as you've directed in your prior Orders in this issue, settlement processes by definition can be a fluid process, and it does not require us and it's not always possible to engage every party in settlement discussions. In this case, we didn't have the time to do that due to time constraints but, again, we indicated to the party both in writing and in other context that we are open to discussions wherever possible.

So for those primary reasons we think it's inappropriate to delay the hearing. In addition to this sort of process and the travel arrangements people have made to be here, we just don't think there's enough reason, any reasons really to justify postponing the hearing.

CHAIRMAN FINLEY: Mr. Ledford, what is a new topic, a new issue, other than something that parties have talked about in their prefiled testimony but they just haven't agreed to or conceded on? What's new?

MR. LEDFORD: I don't believe there are any new issues that are in the redline that have not been presented in one way, shape or form under previous testimony.

CHAIRMAN FINLEY: All right. Then here's what we're going to do. We will not continue this hearing. We will proceed. We've got everybody here in place. And you are free to ask your witnesses questions, if they have a disagreement they'd like to express with respect to the Stipulation. And if we finish and you still believe that you have been disadvantaged by proceeding this afternoon you are welcome to be heard again, and we'll see if you need additional time at that point, if that's okay.

MR. LEDFORD: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: And I will say that the Commission by and large does encourage settlements and we have -- sometimes we have settlements after the hearing even closes, and so I would encourage parties to -- if you would all settle that would be fine with me. (Laughter) But, so please continue to talk and if somebody is disadvantaged by some settlement we'll try to help you out.

Anything else?

(Counsel for all parties shake their heads no)

CHAIRMAN FINLEY: All right, Duke.

MR. JIRAK: Thank you, Mr. Chairman. At this time Duke Energy Carolinas and Duke Energy Progress would like to call the panel of Gary R. Freeman, John W. Gajda and Jeffrey W. Riggins.

GARY R. FREEMAN, JOHN W. GAJDA
and JEFFREY W. RIGGINS, as a panel;
having been duly sworn,

testified as follows:

MR. JIRAK: Thank you, Mr. Chairman. With your permission we would like to introduce each witness individually and each witness will then give a summary of their testimony on behalf of the --

CHAIRMAN FINLEY: Very well.

DIRECT EXAMINATION BY MR. JIRAK:

Q I'll begin with you, Mr. Freeman. Would you please state your name and business address for the record?

A Gary R. Freeman. I reside at 410 South Wilmington Street in Raleigh, North Carolina.

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

A Duke Energy Corporation and I'm the General Manager of Distributed Energy Resource Compliance Origination and Operations.

Q And did you cause to be prefiled in this docket on November 19, 2018, 34 pages of direct testimony in question and answer format?

A I did, yes.

Q Do you have any changes or corrections to be made to that direct testimony at this time?

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 And did you also cause to be prefiled in this docket on January 8, 2019, 35 pages of rebuttal testimony in question and answer format?

A Yes, I did.

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

A No.

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

A Yes.

MR. JIRAK: Mr. Chairman, at this time I would move that the prefiled direct and rebuttal testimonies of Mr. Gary Freeman be copied into the record as if given orally today?

CHAIRMAN FINLEY: Mr. Freeman's direct testimony consisting of 34 pages and his rebuttal testimony consisting of 35 pages is copied into the record as though given orally from the stand.

MR. JIRAK: Thank you.

(WHEREUPON, the prefiled direct testimony of GARY R. FREEMAN is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**DIRECT TESTIMONY OF**
Petition for Approval of Generator	)	**GARY R. FREEMAN**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gary R. Freeman, and my business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?

A. I am the General Manager of Distributed Energy Resources Compliance & Origination for Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from Clemson University and a Master of Business Administration degree from UNC-Chapel Hill.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I have over 38 years of experience in the electric and gas utility industry. In 1999, I joined Progress Energy Corporation, which later merged with Duke Energy. I have worked in various management roles within the Company, including overseeing the energy efficiency and demand response programs and supervising the wholesale power trading/generation optimization functions. Before joining what is now Duke Energy in 1999, I spent 19 years with South Carolina Electric and Gas, where I held various engineering and management roles in transmission, distribution, customer service, wholesale power trading, and human resources.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current role, I oversee the power purchasing and generation interconnection activities for renewable energy resources as well as traditional energy supply resources. I also oversee the development and execution of strategies and compliance plans related to the Renewable Energy Portfolio Standard ("REPS") for Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke" or the "Companies"), as well as renewable energy compliance for Duke Energy Ohio, Inc.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I most recently provided testimony in Docket E-100, Sub 148, regarding certain aspects of the Companies' standard offer avoided cost rates and tariffs under North Carolina's implementation of the Public Utility Regulatory Policies Act ("PURPA"). I have also provided testimony in Docket No. E-7, Sub 1074 on DEC's 2014 REPS compliance report and application for approval of its annual REPS cost recovery rider.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the Commission with an overview of the Companies' nation-leading efforts to interconnect utility-scale solar projects as well as to interconnect smaller generating facilities at the request of our retail customers under the currently-approved North

Carolina Interconnection Procedures ("NC Procedures"). My testimony will also describe the Companies' continued reasonable efforts to comply with the timeframes in the NC Procedures, while balancing the processing of the unparalleled volume of solar Interconnection Customers requesting interconnection with the need to ensure that the surging number of renewable generators requesting interconnection are safely and reliably interconnected to the Companies' distribution and transmission system in a manner that does not adversely impact the Companies' retail and wholesale electric service customers. I will also describe both how the interconnection process becomes more challenging as the amount of interconnected renewable generation increases and the fact that the current serial study process will need to be reformed in order to more effectively address the current and future interconnection queue.

I will also introduce the Companies' other witnesses, Jeffrey W. Riggins and John W. Gajda. Witness Riggins and Gajda address the Companies' participation in the 2017 Advanced Energy-led stakeholder process and provide support for the Companies' more significant revisions to the NC Procedures. These revisions include changes needed to ensure that the Companies are adequately recovering from Interconnection Customers the costs to manage the interconnection process and to ensure that reliability and service quality of the grid is maintained.

Q. PLEASE DESCRIBE THE COMPANIES' OVERALL APPROACH TO THE INTERCONNECTION PROCESS.

A. In the 2015 proceeding to revise the NC Procedures, the Commission recognized North Carolina's unique interconnection landscape and the ongoing challenges that the Companies were facing to manage the unparalleled volumes of utility-scale solar Interconnection Customers. Since 2015, the Companies have invested significant resources in continuing to fulfill their regulatory responsibility to manage the processing of new Interconnection Customers while continuing to meet their critically important public service responsibilities under North Carolina's Public Utilities Act to deliver safe and reliable electric service to our customers. The Companies are continually balancing their dual responsibilities of supporting the growing numbers of new generating facility Interconnection Requests to interconnect to the distribution and transmission system, while also ensuring that service to existing and future retail customers in North Carolina is not degraded due to the operation of these new interconnected generating facilities.

The Companies continue to make reasonable efforts to process all Interconnection Customer generating facilities requesting interconnection to the DEC and DEP distribution and transmission systems in North Carolina. The challenge of meeting these dual responsibilities has grown significantly over the past few years as the number of utility-scale[1] "PURPA sell all" solar facilities under development in North Carolina and proposing to interconnect and sell power to the Companies has grown exponentially.

Q. PLEASE COMMENT ON THE COMPANIES' OVERALL EFFORTS TO ADMINISTER THE INTERCONNECTION PROCESS.

A. I am proud of the Companies' efforts to support both our retail customers' growing interest in installing generating facilities at their homes or businesses and the hundreds of developer-sponsored utility-scale solar facilities that have requested to interconnect to the Companies' systems in North Carolina while also ensuring the continued safe and reliable delivery of electric service to all of our retail and wholesale customers.

As Witness Riggins discusses in more detail, the Companies' have invested in new technology and significantly increased the resources dedicated to supporting the North Carolina interconnection process since 2015. These investments have been necessary to meet the challenges of processing both customer-sited generating facilities, such as rooftop solar, as well as the surging number of utility-scale Interconnection Requests seeking to interconnect to DEC's and DEP's distribution and transmission systems in North Carolina. As a result of these ongoing efforts, since the Commission approved the NC Procedures in May 2015, the Companies

[1] The term "utility-scale" refers to generating facilities one megawatt ("MW") or greater.

have supported approximately 4,600 retail customer interconnections of small solar and other customer-site generating facilities up to 20 kW and entered into over 350 Interconnection Agreements with larger generating facilities above 20 kW during this timeframe.

Witness Gajda provides a technical perspective on the steps the Companies have undertaken to support growing numbers of small customer-sited and larger generating facility interconnections while maintaining safety, reliability, and power quality for the power system as these growing numbers of independently owned and operated generating facilities interconnect and operate in parallel with the Companies' system as a whole. Mr. Gajda also explains how the Companies have proactively implemented new policies, guidelines, and process improvements to ensure that these projects are efficiently interconnected without adversely impacting reliability on the grid for all customers.

Q. HAVE THE COMPANIES CONTINUED TO MAKE REASONABLE EFFORTS TO ADMINISTER THE NC PROCEDURES SINCE THE COMMISSION LAST REVIEWED THE INTERCONNECTION PROCESS IN 2015?

A. Yes. The Commission recognized in the *May 2015 NCIP Order* that the Companies were making reasonable efforts to manage their interconnection queues even as the significant volume of new Interconnection Requests was causing DEP and DEC to fall short of the study timeframes for larger

Section 4 Interconnection Customers.[2] Section 6.1 of the NC Procedures recognizes that compliance with the mandated study timeframes may not be achievable, and, to that end, provides that the utility shall make "reasonable efforts" to meet the timeframes.

Due to continued surging utility-scale solar development in North Carolina since 2015, the Companies have continued to be challenged to meet the designated timeframes for completing System Impact Studies and Facilities Studies for larger interconnection customers under the NC Procedures. I would note, however, that the Companies are more consistently meeting the timeframes for studying and processing the less complex Section 2 and Section 3 Fast Track interconnection customers, which are generally retail customers seeking to install small generating facilities at their home or business. Overall, the Companies continue to fully meet their obligations under the NC Procedures by making "reasonable efforts" to process and study all Interconnection Customers.

Q. HOW WOULD YOU CHARACTERIZE DUKE'S ACHIEVEMENT IN INTERCONNECTING LARGE SOLAR GENERATING FACILITIES?

A. The facts undeniably show that the Companies have continued their nation-leading track record of interconnecting larger utility-scale solar projects. Data from the U.S. Energy Information Administration ("EIA") tracking

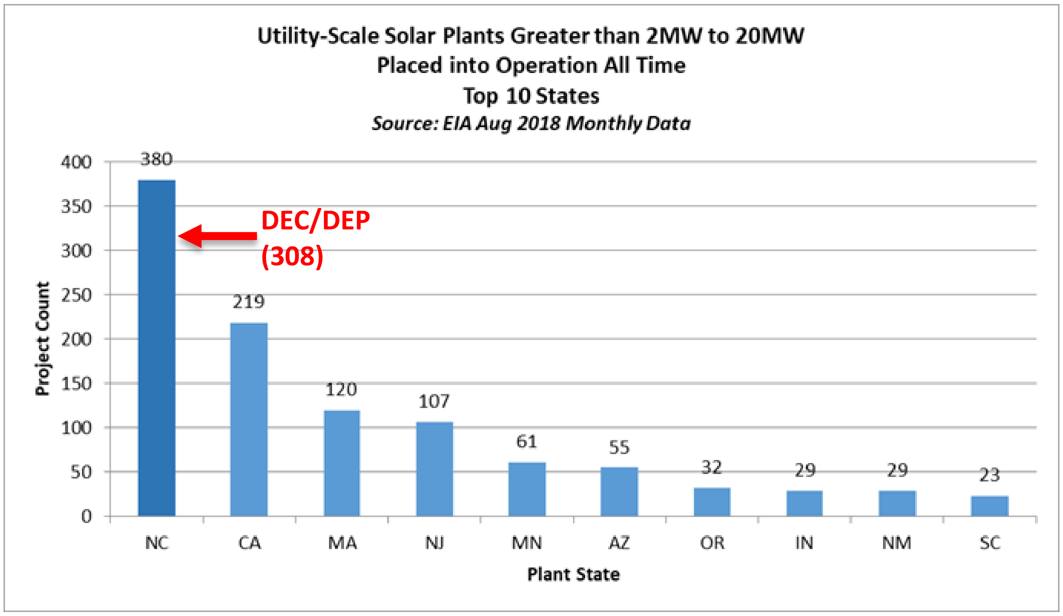
[2] *Order Approving Revised Interconnection Standard*, Docket No. E-100, Sub 101 (May 15, 2015) ("May 2015 NCIP Order").

state-by-state growth in installed utility-scale solar shows North Carolina as a state, and the Companies by themselves, as national leaders in interconnecting utility-scale solar to the grid. No matter how the data is sliced, the Companies have, by any measure, achieved remarkable success at interconnecting utility-scale solar generating facilities.

Q. PLEASE PROVIDE SOME EXAMPLES.

A. Figure 1 presents EIA data through August 2018 (the most current available) identifying the top 10 states for "all time" interconnection of utility-scale solar projects sized between 2 MW and 20 MW. The EIA data shows that North Carolina as a state, and even the Companies by themselves, have interconnected more than twice the total amount of solar projects in this size range than the next closest state of California. The Companies' success is even more stark when compared to other leading states. For instance, Texas has interconnected the tenth largest amount of 2 MW to 20 MW projects. And yet, DEC and DEP together have interconnected 17 times more utility-scale solar PV projects in this size range than Texas even though Texas has nearly 3 times the population of North Carolina. Notably, no other neighboring southeastern States are in the top ten states in this size range.

Figure 1



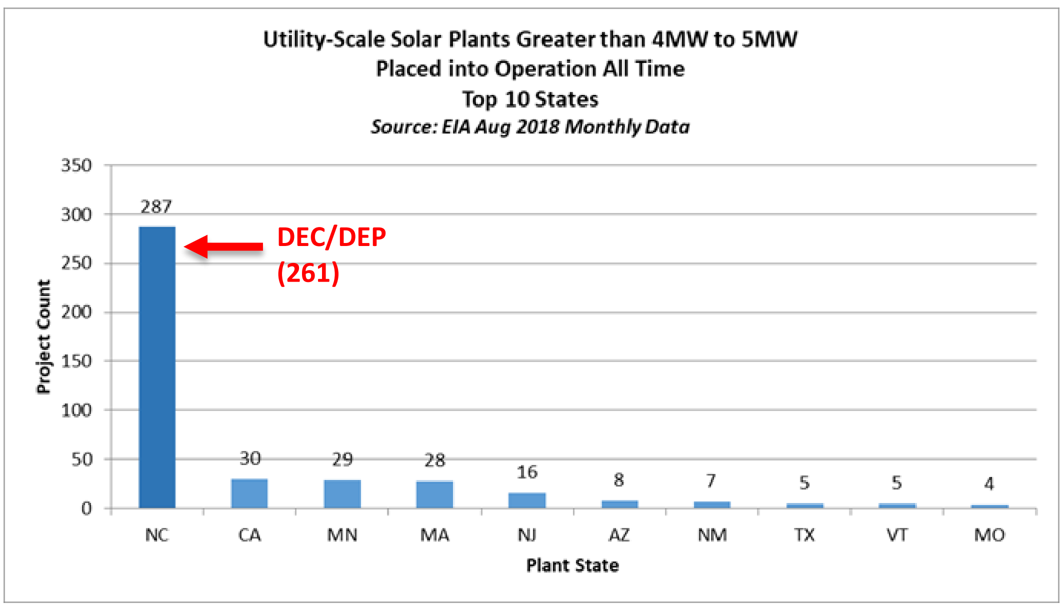
Q. WHAT MAKES NORTH CAROLINA'S SOLAR INTERCONNECTION LANDSCAPE UNIQUE?

A. A number of factors including the state's REPS policy enacted in 2007, the state's 35% Renewable Energy Tax Credit in effect until 2015 as well as the state's implementation of PURPA, which granted 15-year contracts for projects up to 5 MW, combined to foster a truly unparalleled marketplace for the development of 5 MW solar generating facilities. Today, the Companies have a combined 2,647 MW of solar generating facilities already interconnected, including 1,672 MW of distribution-connected solar, with hundreds of projects and thousands of MW more in the queue.

Q. HOW DOES THE NUMBER OF SOLAR INTERCONNECTIONS BETWEEN 4 MW AND 5 MW IN NORTH CAROLINA COMPARE TO THE REST OF THE NATION?

A. As shown in Figure 2 below, the amount of 4-5 MW solar generating facilities interconnected in North Carolina simply dwarves all other states. North Carolina has nearly 10 times more 4-5 MW solar projects interconnected than California, the next closest state. Missouri is ranked tenth nationally with respect to 4-5 MW projects. The Companies alone have interconnected 65 times more 4-5 MW projects than Missouri. Once again, no other southeastern states are even in the top ten in this size range.

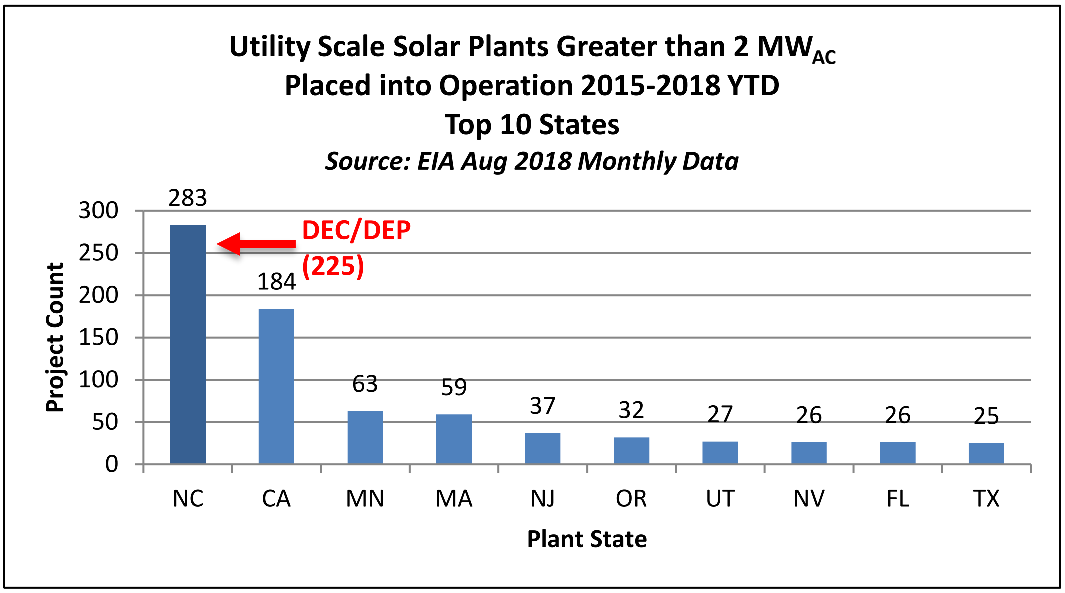
<u>Figure 2</u>



Q. SINCE 2015, HAVE THE COMPANIES INTERCONNECTED MORE UTILITY-SCALE SOLAR PV GENERATING FACILITIES THAN ANY OTHER STATE IN THE COUNTRY?

A. Yes. As shown in Figure 3 below, over the period of 2015-2018, the Companies have interconnected significantly more solar projects greater than 2 MW than any other state. Every one of these projects has required significant time to study, engineer, and construct the interconnection facilities and upgrades necessary to interconnect the generating facility and to enable energy delivery to the grid.

Figure 3



Q. ARE THE SMALLER UTILITY-SCALE SOLAR PROJECTS CONNECTING TO THE COMPANIES' DISTRIBUTION NETWORK EASIER TO STUDY THAN THE LARGER, TRANSMISSION-CONNECTED PROJECTS?

A. No. While there are some limited differences in the study process, smaller utility-scale solar projects require the same in-depth technical review and analysis as is required for larger utility-scale projects. Distribution-connected utility-scale solar interconnections have also created additional complexities not previously seen for larger transmission-connected generating facilities. As further discussed by Witness Gajda, the Companies have invested significant resources since 2015 to proactively evaluate whether pre-existing study methods and assumptions appropriately recognized the potential power quality and reliability impacts of smaller utility-scale solar projects interconnecting to the distribution system, especially when located near a sensitive load customer. The significant and unparalleled growth of utility-scale QF solar facilities interconnecting to the Companies' distribution systems in North Carolina has required DEC and DEP to continually reassess what constitutes "Good Utility Practice" and to develop new technical standards applicable to these generating facility interconnections in order to mitigate the potential for localized power quality impacts and distribution system reliability risks.

Q. ARE YOU AWARE OF ANY OTHER STATE THAT HAS COMPARABLE LEVELS OF DISTRIBUTION-CONNECTED UTILITY-SCALE SOLAR PROJECTS?

A. No. As is reported by the EIA, the amount of utility-scale solar projects connecting to the distribution system is not "normal" outside of North Carolina and, therefore, the Companies are essentially operating in a unique "living laboratory" of utility-scale solar deployment operating in parallel with their general distribution systems.

Q. WHAT ARE THE PRIMARY ECONOMIC FACTORS NOW DRIVING THE GROWTH OF SOLAR IN NORTH CAROLINA?

A. North Carolina has attracted the attention of developers from all over the world seeking to develop solar generating facilities in the state. As discussed above, the growth was first driven by a combination of factors, including the PURPA standard offer framework that offered fixed contracts to projects up to 5 MW. In order to minimize interconnection costs, these smaller utility-scale projects sought interconnection at the general distribution system level at an unprecedented and unparalleled level.

More recently, Session Law 2017-192 ("HB 589") shifted the state's renewable procurement strategies away from standard offer contracts and towards a competitive procurement process. In total, the legacy PURPA projects combined with the HB589 procurement directives will equate to approximately 7,000 MW of renewable generation that either has been or will be interconnected to the Companies' distribution system and transmission network. I would also highlight the HB 589 has created new opportunities through the Commission-approved solar rebates program and third-party leasing of small solar facilities for our retail customers to promote interconnecting solar "behind-the-meter" at their homes or businesses.

Q. AS SOLAR PENETRATION LEVELS INCREASE, ARE INTERCONNECTIONS BECOMING MORE CHALLENGING?

A. Yes, interconnecting additional utility-scale solar generating facilities is becoming increasingly difficult. Many areas across the Companies' distribution systems, especially in DEP, are already heavily saturated with utility-scale solar generating facilities. In such areas, the only functional and feasible solution for interconnection of additional utility-scale projects will involve either major infrastructure "Upgrades," such as additions to local substations and distribution systems, and/or massive redesign of the distribution system as a whole.

This is because there are simply functional limits to the amount of generating capacity of any type, including solar, that can connect to the current distribution system, short of changing the nature of the distribution system itself. Therefore, the solutions to connect additional utility-scale solar generating facilities to the Companies' distribution system are increasingly complex and costly, generally involving a significant amount of new distribution line construction over new rights-of-way, which often can be difficult to procure within the required timeframes.

And as will be discussed in more detail later, the cumulative impact of both transmission- and distribution-connected projects mostly located in the eastern part of the state is overloading several critical transmission facilities and is triggering the need to spend several hundred million dollars on transmission network upgrades to continue to interconnect additional solar generating facilities. In other words, interconnection studies are now identifying that the cumulative impact of interconnecting the unparalleled level of utility-scale solar to the distribution and transmission system is now causing grid constraints to interconnect the next generating facility to increasingly-large areas of the system. These grid constraints were not observed at lower penetration levels, thus increasing the breadth and depth of studies needed to ensure power quality remains acceptable.

Q. PLEASE DISCUSS FURTHER HOW THE CONSTRUCTION CHALLENGES OF INTERCONNECTION INCREASES AS SOLAR PENETRATION LEVELS INCREASE.

A. The increasing solar penetration levels not only give rise to more complex study requirements, but also lead to more challenging construction projects. The Company has successfully completed numerous such construction projects, but the complexity of these undertakings illustrates the challenges and time-consuming nature of interconnecting so many solar generating facilities.

Q. HOW DOES THE PRESENCE OF SUBSTANTIAL AMOUNTS OF UTILITY-SCALE SOLAR PROJECTS CONNECTED TO THE DISTRIBUTION SYSTEM IMPACT THE COMPANIES' ABILITY TO MODIFY THE DISTRIBUTION SYSTEM TO MEET GROWING LOAD AND ENSURE RELIABILITY?

A. The Companies actively manage and plan for load as they fulfill their obligation to serve current and future retail customers throughout the state. As load patterns change, the distribution system often must be altered over time to serve this load, but utility-scale solar generating facilities interconnected with the distribution system constrain the Companies' technical options and may, in some cases, require more costly solutions.

Interconnection studies of solar generating facilities connected to the distribution network, by their nature, study the facility on its native radial circuit, and, once connected, the facility and "its substation" are now "married" in a sense. The option to transfer some of the distribution circuit to another source of feed (substation)—an option that was historically routinely used to accommodate growing load—will be severely limited in the case of circuits with interconnected utility-scale solar generation. However, without the solar generating facility, that section of circuit can easily be transferred to another feed.

Since solar generating facilities on distribution operate unscheduled and their output has no specific relation in time to the local load, the section of distribution circuit between the solar farm and its substation has essentially become a transmission line, responsible for delivering the solar generating facility's energy to the substation and transmission system. The distribution system is becoming inundated with such sections, and configuration changes to accommodate changes in load patterns in these areas will, by definition, be more expensive than had the solar farm not been there.

Q. IN ADDITION TO CONGESTION AT THE DISTRIBUTION LEVEL, ARE THE COMPANIES BEGINNING TO EXPERIENCE CONGESTION AT THE TRANSMISSION LEVEL?

A. Yes. As penetration levels have increased, areas of the Companies' transmission networks have reached or are close to reaching the limits of current transmission capacity availability and capability to interconnect additional generating facilities and transmit the energy from these generators to the Companies' customer load centers that are far away. As with the distribution system, the transmission network was initially designed in an integrated and least cost manner to provide transmission capability to deliver power from the Companies' generating facilities to reliably serve load customers throughout DEC's and DEP's system. Existing transmission assets have a finite amount of capacity and once the transmission network capacity is fully consumed, network upgrades are required to accommodate additional generating facilities.

Q. DO THE GROWING AMOUNTS OF GENERATING CAPACITY INTERCONNECTED TO THE COMPANIES' TRANSMISSION AND DISTRIBUTION SYSTEM AFFECT THE AVAILABILITY OF TRANSMISSION CAPACITY AND THE NEED TO UPGRADE THE TRANSMISSION NETWORK?

A. Yes. It is important to recognize that both transmission and distribution connected generating facilities have contributed to the transmission congestion issues.

Q. PLEASE PROVIDE AN EXAMPLE OF A TRANSMISSION NETWORK UPGRADE THAT HAS BEEN IDENTIFIED.

A. Through the interconnection study process, DEP has determined that significant transmission network upgrades will be needed to interconnect additional generation in the southeastern North Carolina area of DEP East. These upgrades have been triggered by the cumulative amount of generation located in southeastern North Carolina, where the need for the increased generation to flow northwest toward the large load centers, such as Wake County, has caused several transmission line segments to now reach their power flow limits. This congested area in DEP East has over 100 in-service or under construction solar generating facilities totaling 1,347 MW. This includes 16 transmission-connected projects totaling 898 MW and 99 distribution-connected solar projects totaling 449 MW. Notably, there are over 3,500 of MW of additional generating facilities in the queue that are seeking to interconnect in this congested area.

Q. WHAT ACTIONS IS DEP TAKING TO ADDRESS THIS CONGESTION ISSUE?

A. As required by the NC Procedures and the Federal Energy Regulatory Commission ("FERC") Joint Open Access Transmission Tariff ("OATT"), the identified upgrades have been assigned to specific Interconnection Customers. The total cost of the upgrades is approximately $200M and, assuming that identified Interconnection Customers commit to the projects in the near term, the current projected completion date for the projects is the end of 2022 (though this date is subject to change).

Q. PLEASE DESCRIBE THE WORK THAT IS REQUIRED.

A. The identified Network Upgrades to support interconnection of additional solar resources in this particular area consist primarily of re-conductoring transmission lines to increase capacity. Over 63 miles of transmission reconductoring will be required:

- Cape Fear – West End 230kV line (~26.6 miles) and 4.4 miles to uprate
- Erwin-Fayetteville East 230kV line (~23 miles)
- Erwin-Fayetteville 115kV line (~8.7 miles)
- Fayetteville – Faye DuPont 115kV line (~3.2 miles)
- Rockingham – West End 230kV West line (uprate ~8 miles of line)

Q. PLEASE DESCRIBE WHY SUCH UPGRADES WILL TAKE SEVERAL YEARS TO COMPLETE.

A. Reconductoring this amount of transmission line is an enormous undertaking. Rebuilding a transmission line requires the line to be removed from service. These transmission line segments are part of DEP's critical transmission network, and, in order to maintain grid stability, can only be taken out of service for approximately 12 weeks during the spring and fall shoulder months when transmission flows are manageable. To expedite completion, multiple line crews will potentially be involved in each of the 12-week seasonal (spring & fall) intervals.

Q. HOW MANY OTHER PROJECTS ARE DEPENDENT ON THESE UPGRADES?

A. Until the identified Network Upgrades are placed in service, the other projects in the congested area remain interdependent with these Upgrades and cannot be interconnected in a safe and reliable manner in accordance with Good Utility Practice. The need for these upgrades are impacting more than 500 MW of distribution projects and 3,000 MW of transmission projects, none of which can be interconnected until these upgrades are constructed.

Q. WHAT ARE THE COMPANIES' PLANS FOR SUCH IMPACTED PROJECTS UNTIL THE UPDGRADES CAN BE BUILT AND PLACED INTO SERVICE?

A. Under Section 1.8 of the NC Procedures, the impacted projects are deemed interdependent. However, the Companies have met with a number of developer stakeholder groups as well as the Public Staff to discuss next steps and to receive feedback on the best plan to manage the projects located in these congested areas. The Companies expect that such conversations will continue.

Q. ARE THERE OTHER MAJOR NETWORK UPGRADES THAT WILL BE NEEDED TO CONTINUE TO INTERCONNECT PROJECTS?

A. Yes, as the penetration levels of solar generating facilities continue to increase, there will be additional areas of congestion in both DEP and DEC service territory that will necessitate further transmission network upgrades.

Q. PLEASE DESCRIBE THE CONCEPT OF INTERDEPENDENCY.

A. In the context of the interconnection process, interdependency means that one or more interconnection requests are impacted or dependent on the decisions and study results of a project that entered the interconnection queue ahead of the interdependent projects. Under the NC Procedures, a project B is interdependent on a project A, and an "on hold" project is interdependent on both project A and project B. When solar penetration levels were more limited and there were fewer projects connected to the system, interdependency constraints were both less frequent and less complex, where for example two projects on the same circuit were interdependent to each other. As penetration levels increased, interdependencies started to arise between two projects on adjacent circuits or connected to the same substation. Now, with the high penetration levels, especially in DEP, interdependency is occurring at the transmission network level, which results in a much larger number of projects being impacted.

Q. HOW DOES INTERDEPENDENCY RESULT IN DELAYS IN THE INTERCONNECTION OF SOLAR PROJECTS?

A. The interdependency concept in NC Procedures was designed to recognize or identify the serial order in which interconnection studies are to be completed. By designating projects as As, and Bs, and all other projects as "on hold," the intent was to focus study times on the project As and Bs.

As the amounts of solar generation seeking to interconnect to the same distribution circuit or substation has increased, more projects have been deemed Project Cs and placed on hold in accordance with the NC Procedures pending resolution of the Project A and Project B. Following these interdependency provisions has necessarily caused delays in the Section 4 study process for some Interconnection Customers, as numerous utility-scale solar QF projects are continuing to submit requests to interconnect on the same distribution circuits and behind the same substations as both installed solar QFs and other projects in the queue. And as discussed above, interdependency will have an even more widespread impact as interdependency has "extended up" to the transmission network level and the number of projects identified as interdependent on earlier projects has risen sharply.

Q. HOW ARE DISPUTES FURTHER CHALLENGING THE COMPANIES' ABILITY TO PROCESS INTERCONNECTION REQUESTS IN A TIMELY MANNER?

A. Once again, as available grid capacity has been consumed by earlier queued projects, informal and formal disputes by developers challenging distribution and network upgrade cost estimates, construction timeframes, and other aspects of the study process have become more common. These disputes in turn consume resources and have delayed the study of other projects. Witness Riggins provides additional information on the Companies' experience under the dispute resolution process and the Companies' proposed changes to Section 6.2.

Q. PLEASE DESCRIBE THE COMPANIES EFFORTS TO IMPROVE THE EFFICIENCY OF THE INTERCONNECTION PROCESS?

A. Duke has exerted extraordinary efforts to respond to this continued surge of utility-scale solar growth and the increased complexity of North Carolina's interconnection landscape. As further discussed by Witness Gajda, the Companies have made continuous improvements to the study process and sought to increase transparency for customers. Witness Riggins also addresses how the Companies' Distributed Energy Technologies' organization and other departments within Duke Energy have increased project management, study engineering, construction, and technological resources assigned to support the interconnection process.

Q. DESPITE THE FACT THAT THE COMPANIES HAVE ACHIEVED AN INDUSTRY-LEADING NUMBER OF INTERCONNECTIONS, IS THE INTERCONNECTION QUEUE ANY SMALLER?

A. No. Despite the Companies' efforts, the interconnection queue continues to grow. In January 2017, there was a combined 4,879 MW of solar generation in the Companies' North Carolina queues and, as of September 2018, that figure has increased to 7,798 MW. In addition to these projects, the South Carolina interconnection queue has grown significantly from 1,679 MW of solar generation in January 2017 to 6,518 MW as of September 2018. This is important since the DEC and DEP systems electrically do not recognize the state boundaries, and projects located in either state have impacts on the grid in the other state.

The charts presented in Figures 4-5 below also illustrate the continued growth in the Companies' queues for North Carolina and South Carolina, respectively. Figure 4 also illustrates that the smaller utility-scale interconnection requests have declined significantly (as would be expected given the policy shift in North Carolina) while larger, transmission-connected interconnection requests have grown.

Figure 4

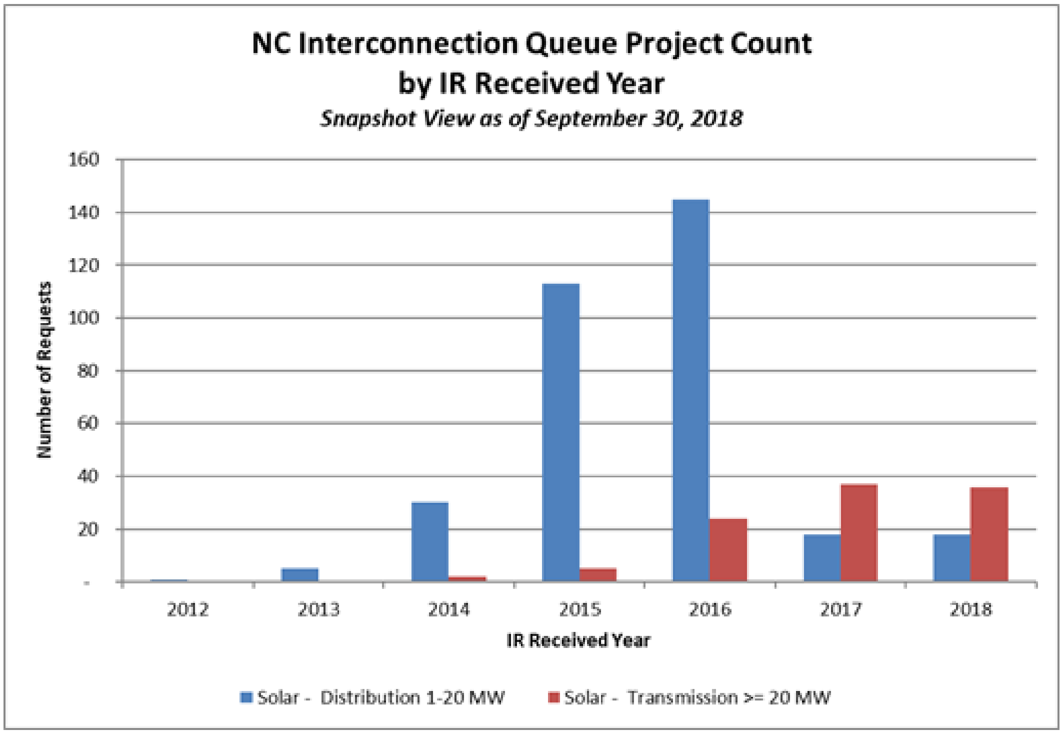
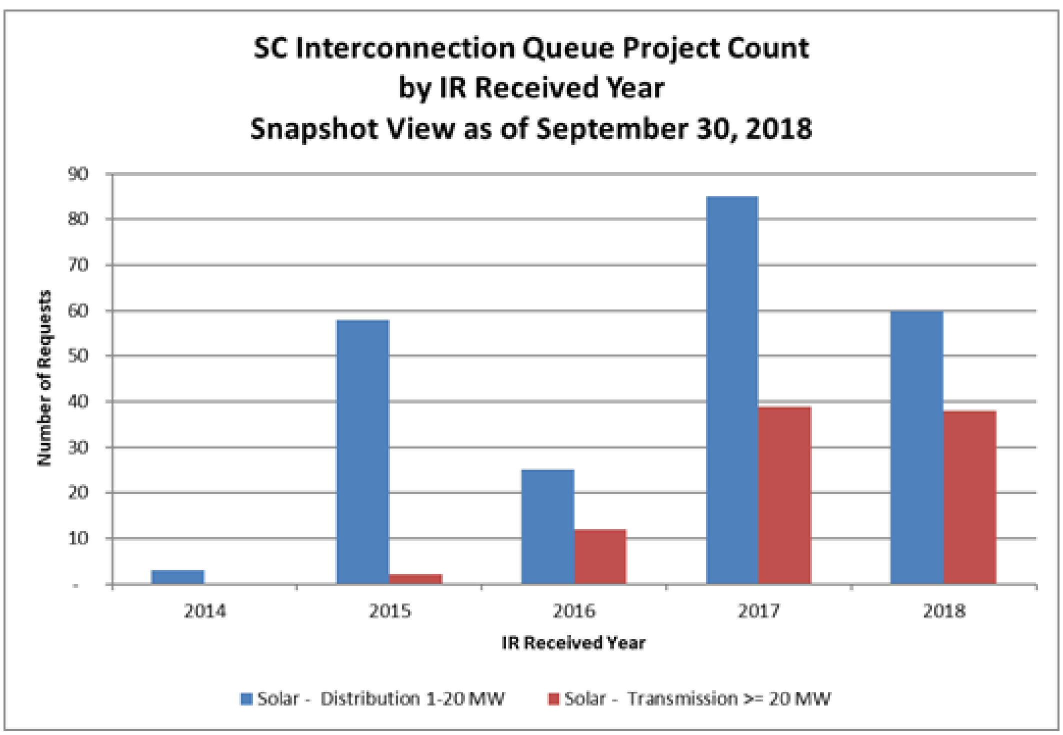


Figure 5

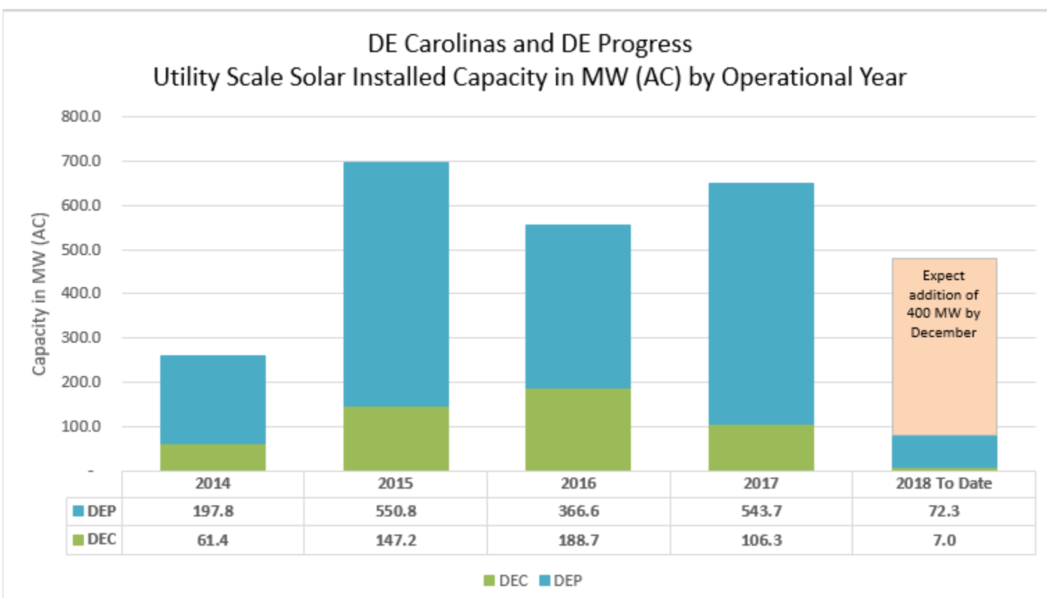


On a total system basis between DEC and DEP and North Carolina and South Carolina, the queue has grown to over 14,000 MW of solar and also includes an additional 10,000 MW of non-renewable facilities.

Q. ARE THE COMPANIES MAINTAINING THE SAME LEVEL OF COMPLETED INTERCONNECTIONS EACH YEAR FOR UTILITY SCALE PROJECTS?

A. Yes, at a high level DEC and DEP are maintaining the same level of completed interconnections in each year for utility-scale projects. Figure 6 illustrates that in each year since 2015, DEC and DEP have achieved a generally consistent amount of interconnections, averaging approximatley 600 MW per year.

<u>Figure 6</u>

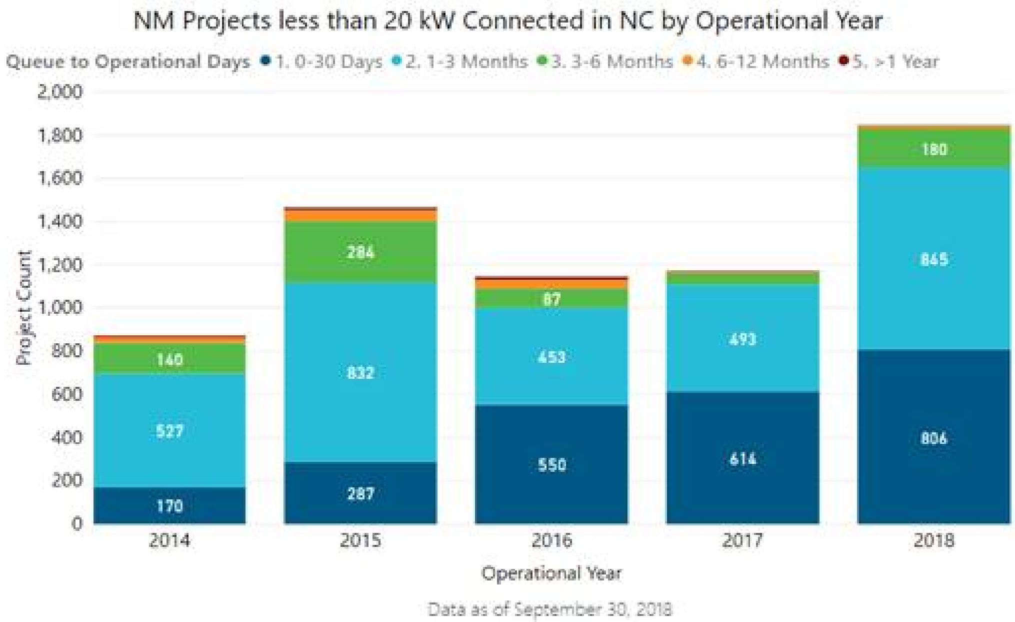


To further put that into perspective, based on EIA data, New Jersey is the ninth leading state in the nation all time in terms of interconnected solar projects greater than 2 MW. The Companies' 634 MW annual average exceeds the total cumulative amount connected by New Jersey all time.

Q. ARE THE COMPANIES EFFECTIVELY MANAGING THE INTERCONNECTION PROCESS FOR SMALLER PROJECTS SUCH AS NET METERING PROJECTS UNDER THE NC PROCEDURES?

A. Yes. As presented in Figure 7 below, the Companies have been much more successful in complying with processing timeframes in the NC Procedures for small Section 2 generating facilities, which are typically residential net metering customers. Including North Carolina and South Carolina, growth of these size facilities is increasing dramatically year over year. As shown in Figure 7, most facilities are able to connect to the grid within 0-30 days or within 1-3 months. Any delays in this process typically involve the completion of installation and local inspections and the ability to quickly replace metering and establish billing.

Figure 7



Q. WHY ARE THE COMPANIES SUPPORTING TARGETED REVISIONS TO THE NC PROCEDURES AT THIS TIME?

A. Duke worked collaboratively with the Public Staff and other stakeholders during the 2017 Advanced Energy stakeholder process, and, in January 2018, proposed limited revisions to the NC Procedures designed to improve the interconnection study process. The key issues being addressed in these proposed changes to the NC Procedures are supported by Witnesses Gajda and Riggins and include: Affected System coordination, expedited study process changes to support HB 589, material modification definition, and energy storage.

Q. DO THE COMPANIES BELIEVE THAT FURTHER CHANGES ARE STILL NEEDED TO ADDRESS THE CLOGGED QUEUE AND THE SIGNIFICANT FUTURE DEVELOPMENT REQUIRED TO MEET THE HB 589 PROCUREMENT OBLIGATIONS?

A. Yes. As stated above, the current proposed changes focused on small, but needed changes to the interconnection process. However, the queue and study complexities continue to increase with no end in sight. The Companies are requesting Commission approval of the current proposed changes presented in the Redline to the NC Procedures sponsored by Witness Gajda but also note that more comprehensive reform will be needed in the near term to address the interconnection queue.

Q. IS THE CURRENT SERIAL STUDY PROCESS SUSTAINABLE?

A. No, the current serial study process is not sustainable as it would likely require decades to serially study and potentially connect the 14,000 MW of renewable generating facilities that are in the current North and South Carolina DEP and DEC queues. The Companies believe that it is now necessary to transition from a serial study process to a cluster study process, which is a process used by an increasing number of regional transmission organizations ("RTO") and utilities in other areas of the country to more efficiently study and allocate the costs of transmission network upgrades. To that end, the Companies are closely following a Public Service Company of Colorado ("PSCO") stakeholder process designed to address PSCO's clogged queue of approximately 23,000 MW on a 8,500 MW system. The

Companies are also reviewing a related process undertaken by the Public Service Company of New Mexico ("PNM") that ultimately reduced PNM's queue from 10,000 MW to 1,000 MW on a 2,500 MW system. Many RTOs across the country are also continuing to refine and modify their interconnection processes, and all of these entities have evolved to a cluster study type of process for larger size projects.

Q. PLEASE EXPLAIN THE FUNDAMENTAL FLAWS OF THE SERIAL STUDY PROCESS.

A. Generally, when the interconnection queue was small and no major transmission network upgrades were being triggered, the serial study process was workable. However, as larger transmission network upgrades are now increasingly being triggered, the serial study process is untenable and could result in further paralysis of the queue due to the large upgrade costs being assigned to one project and developers being unable to achieve funding of these particular network upgrades.

Q. WHAT SPECIFIC NEXT PLANS ARE THE COMPANIES PLANNING TO TAKE TO SEEK TO TRANSITION TO A FULL CLUSTER STUDY APPROACH?

A. The Companies hosted an initial stakeholder meeting in June to receive feedback regarding transitioning to a cluster study approach. Stakeholders seemed to agree that queue reform is needed and that a cluster study approach may be more workable to process the hundreds of projects and thousands of megawatts of generation in the Companies' queues. However, the "devil is in the detail" on how to transition from the current serial "first in/first out" approach to a clustered study approach. Issues that will need to be addressed include: defining the clusters, study timing, cost allocation and early funding commitments to remain in the study, and grandfathering.

In parallel with supporting the modifications to the NC Procedures presented to the Commission for approval now, the Companies are also working on a queue reform proposal to share with the Public Staff and other stakeholders to develop a more sustainable approach to studying projects, assigning upgrades and collecting the costs of those upgrades. The Companies anticipate requesting Commission approval of additional revisions to the NC Procedure to accomplish these changes, which changes would need to be aligned with FERC OATT.

Q. WHAT FACTS DETERMINE WHETHER A PARTICULAR INTERCONNECTION REQUEST IS STATE JURISDICTIONAL OR FERC JURISDICTIONAL?

A. Although I am not an attorney, I have been advised that the appropriate jurisdiction is a matter of law. If a project is a QF that intends to sell all output to Duke and will directly connect to Duke's system, then it must be interconnected under the NC Procedures. If not, then it must be interconnected under the FERC OATT (with one minor exception).

Q. HOW MANY PROJECTS ARE CURRENTLY SEEKING TO INTERCONNECT UNDER THE FERC-JURISDICTIONAL PROCESS AS OPPOSED TO THE APPLICABLE STATE PROCEDURES?

A. In DEC, approximately one quarter of the currently pending Interconnection Requests are FERC-jurisdictional. In DEP, approximately one third of the currently pending Interconnection Requests are FERC-jurisdictional.

Q. WHAT ARE THE PRIMARY CHALLENGES OF ADMINISTERING TWO DISTINCT INTERCONNECTION PROCESSES?

A. While there is a single, unified queue for both state and FERC-jurisdictional projects, there are some substantial differences between the FERC and state processes. Most notably, under the FERC process, (1) the concept of interdependency is not applicable (2) interconnection customers can suspend the FERC interconnection agreements for up to three years; (3) full prepayment of identified upgrades is not required; and (4) full repayment to Interconnection Customer of amounts advanced for identified upgrades is required.

Q. HOW WILL THE SEPARATE FERC- AND STATE-JURISDICTIONAL PROCESSES INFORM THE QUEUE REFORM EFFORTS?

A. Any future queue reform efforts will need to ensure alignment between the two processes, which may necessitate parallel approval efforts not only in both North and South Carolina but also at FERC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(WHEREUPON, the prefiled rebuttal testimony of GARY R. FREEMAN is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**REBUTTAL TESTIMONY OF**
Petition for Approval of Generator	)	**GARY R. FREEMAN**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Gary R. Freeman, and I am the General Manager of Distributed Energy Resources Compliance & Origination for Duke Energy Corporation ("Duke Energy"). My business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies").

Q. ARE YOU THE SAME GARY R. FREEMAN WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony provides a high-level response to certain issues raised by Public Staff and other intervenor witnesses in direct testimony pre-filed in this docket. Rebuttal testimony concurrently filed in this docket by the Companies' witnesses John W. Gajda and Jeffrey R. Riggins will respond in more detail to certain other issues and will support the Companies' proposed modifications to the North Carolina Interconnection Procedures ("NC Procedures").

My rebuttal testimony first highlights the Companies and the Public Staff's general alignment on a number of proposed modifications to the NC

Procedures, as well as the Public Staff's support of the Companies' approach to applying Good Utility Practice under the NC Procedures.

I then address criticisms lodged by certain parties in this docket and in other forums regarding the amount of time that is often required for the Companies to interconnect utility-scale solar generation projects. First and foremost, these criticisms fail to take into account the extensive evidence demonstrating the Companies' national leading successes in interconnecting distributed generation, as described extensively in my direct testimony. Secondly, such criticisms simplistically assess an incredibly complex undertaking—the study, engineering and construction required to interconnect utility-scale distributed generation—based solely on the amount of time particular projects have been in the queue, while failing to recognize the many complex factors contributing to developers' experienced "delays" in the interconnection process. I then explain that, in many cases, the amount of time that projects remain in the queue is primarily driven by factors outside the Companies' control, including the interdependency provisions of the NC Procedures and developer actions.

The Companies have and will continue to exert significant efforts to expedite the interconnection process and have invested substantial resources in doing so, which resources have led directly to the Companies' nation-leading interconnection efforts. And the Companies understand the financial impact that long interconnection wait times can have on Interconnection Customers. But those that view the long interconnection wait times as simply a product of lack of effort or administrative efficiency on the part of the Companies simply do not understand the complexity of the interconnection process or the many factors influencing the interconnection process timeline outside the Companies' control.

Finally, my testimony further describes the Companies' plans to move to full grouping studies and also responds to certain recommendations made by the Public Staff in its pre-filed direct testimony.

Q. WHAT ACTUAL CHANGES TO THE NC PROCEDURES HAVE THE COMPANIES PROPOSED IN THIS PROCEEDING?

A. The Companies' proposed changes to the NC Procedures are attached to the pre-filed rebuttal testimony of DEC/DEP witness Gajda. The proposed modifications are discussed in more detail by DEC/DEP witnesses Gajda and Riggins and are substantially similar to those modifications jointly filed by the Companies and Dominion Energy North Carolina ("DENC") in this docket on March 12, 2018. In addition, a handful of additional modifications have been identified in the interim period, as further addressed in these other witnesses' testimony.

Q. IN YOUR OPINION, IS THERE SUBSTANTIAL ALIGNMENT BETWEEN DUKE AND PUBLIC STAFF WITH RESPECT TO SUCH PROPOSED MODIFICATIONS?

A. Yes, the Companies have proposed a substantial amount of modifications to the NC Procedures. Public Staff and Duke are aligned on nearly all modifications, with a few exceptions and the Companies are committed to engage with Public Staff (as well as other intervenors) regarding potential resolution of the remaining outstanding issues.

Q. PLEASE BRIEFLY ADDRESS THE PUBLIC STAFF'S TESTIMONY REGARDING THE COMPANIES' EFFORTS TO ADMINISTER THE INTERCONNECTION PROCESS AND THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE.

A. Public Staff Witness Lucas testifies that North Carolina's "unprecedented growth of solar could only have been brought about by cooperation of the Utilities" and he notes that, despite facing significant challenges, "the Utilities appear to have made good faith efforts to interconnect DG."[1] Similar to my direct testimony, Public Staff witness Williamson highlights that North Carolina is in a unique position nationally due to the amount of utility-scale, grid-tied, intermittent, and non-dispatchable Qualified Facility ("QF") generation on its distribution system, and increasingly on its transmission system. As discussed further by DEC/DEP witness Gajda, witness Williamson expresses the Public Staff's support for the manner in which the Companies have administered the interconnection process and applied "Good Utility Practice" to safely and reliably interconnect additional generation to the Companies' systems.

[1] Public Staff Lucas Direct Testimony, at 32.

Q. PLEASE REITERATE THE COMPANIES' POSITION REGARDING ITS SUCCESS IN INTERCONNECTING PROJECTS.

A. As was discussed at length in my direct testimony, the Companies are a national leader in North Carolina with respect to the interconnection of distributed generation. By any measure, the Companies' efforts have been remarkable and at the very forefront of the nation.

And the Companies have achieved this success while continuing to ensure that system safety, reliability and power quality is maintained for all customers through the consistent implementation of non-discriminatory technical standards that have been identified as being necessary in North Carolina's "living laboratory" of utility-scale, distribution-connected solar resources. In addition, the Companies have sought, where possible within the existing construct, to allocate the costs arising from the interconnection process to Interconnection Customers.

Public Staff witness Lucas acknowledged the track record of the Companies in observing that "[e]leven years ago, North Carolina had less than one megawatt of interconnected solar capacity but now has over 3,000 megawatts."[2] As noted above, witness Lucas highlights the Companies' "good faith efforts" to interconnect third-party generation projects and to support North Carolina's unprecedented solar growth. In 2018, Duke interconnected over 450 MW of solar PV, continuing its "good faith efforts"

[2] *Id.*

to interconnect third-party solar even as the increasing penetration has made interconnection solutions more complex. Almost 400 MW of these projects were completed in the last couple of months, requiring a huge commitment from the Companies' employees needed to achieve such success under tight timelines.

Q. A NUMBER OF PARTIES CRITICIZED THE LENGTH OF TIME THAT IT TAKES DUKE TO STUDY AND INTERCONNECT PROJECTS. PLEASE RESPOND TO SUCH CRITICISM.

A. The Companies' success at interconnecting projects speaks for itself. However, it is important to also note that summarily asserting that the total amount of time a project has been in the queue is evidence that the Companies are somehow failing its obligations under the NC Procedures is almost absurdly simplistic and ignores the myriad of factors that impact an Interconnection Customer's study and processing priority and the amount of time a project will remain in the queue.

Duke has previously discussed such factors and they include but are not limited to the following: interdependency, delay in provision of information from developers, developer-requested extensions, cure periods, informal and formal disputes, developer requests for additional information, and complex engineering and construction requirements. To assist the Commission in understanding the complexity of the process, I will provide a general description of the System Impact Study ("SIS") process for distribution-connected projects. In doing so, I will also describe the fact that a substantial portion of the time required to complete the SIS is outside of the control of the Company and, furthermore, that it is the actions of the developers themselves that, in many cases, contribute to a lengthy study process for projects, which, in turn, impacts other projects in the queue.

Q. WHAT IS THE SIS AND WHAT IS ITS SIGNIFICANCE?

A. Under the NC Procedures Section 4 full study process as further discussed by DEC/DEP witness Gajda, the SIS is the initial modeling and engineering study designed to assess the impact of interconnecting the generating facility with the Companies' distribution or transmission system. The SIS process is detailed in Section 4.3 of the NC Procedures. The SIS process is then followed by the more detailed Facilities Study evaluation, which provides the Interconnection Customer a more detailed cost estimate prior to the Companies undertaking initial construction planning and drafting and delivering an Interconnection Agreement to the Interconnection Customer under Section 5.

Q. ARE THERE ASPECTS OF THE SIS TIMELINE THAT ARE OUTSIDE OF THE COMPANIES' CONTROL?

A. Yes. In fact, when considering a generic SIS study timeline, much of the timeline is comprised of discrete steps where the Companies are required to wait on developer action or response. In other words, the timeline for completion of SIS is often more influenced by the actions of the developer than by the actions of the Companies.

Furthermore, this assessment does not even consider the impact of extensions, cure periods, and formal and informal developer challenges. When a developer requests extensions, is granted cure periods or formally or informally challenges the Companies' conclusions, the portion of the SIS timeline that is outside of the Companies' control increases even further.

Q. PLEASE PROVIDE SOME EXAMPLES OF THE PORTIONS OF THE DISTRIBUTION SIS TIMELINE THAT ARE OUTSIDE OF THE COMPANIES' CONTROL.

A. The SIS process for distribution projects is comprised of a number of decisions or actions steps, and for each step, I have identified below the portion of the timeline that is outside of the Companies' control and, for purposes of this analysis, highlighted commonly requested extension periods:

[Chart on the following page]

Step	Developer Action	Time Added to SIS Process Timeline by Developer Action
Line Voltage Regulator("LVR") Review	• No developer action needed	N/A
Obtain Right of Way (if LVR impact is determined)	• Developer is required to select an LVR option and is given 15 business days. It is very common for developer to request one or more additional 15 business day extensions, leading to a total possible delay of 45 business days or more. • In those cases where a developer elects to pursue its own Right of Way, the developer is provided 30 business days. It is very common for a developer to request one or more extensions, leading to a total possible delay of 90 business days or more.	**+45 business days** (or more) **+90 business days** (or more)
Mitigation Options	• Once the volt/var study is complete, mitigation options are provided and the developer is given 15 business days to select a mitigation option. It is very common for developers to request one more extensions, leading to a total possible delay of 45 business days or more. • Once a developer selects a mitigation option, it is also necessary for the developer to provide updated documents since the project now to be studied differs from what was reflected in the Interconnection Request. Developer is given 10 business days but it is very common for a developer to request one or more extensions, leading to a total possible delay of 30 business days or more	**+45 business days** (or more) **+30 business days** (or more)
Transformer Inrush	• Developer is given 15 business days to select the type of inrush study	**+15 business days** (or more)

Step	Developer Action	Time Added to SIS Process Timeline by Developer Action
	• Developer is given 30 business days to provide transformer data. Often, corrections are needed and the developer is given 10 business days for each correct. • Developer is given 30 business days to select the inrush option.	**+30 business days** (or more) **+30 business days**
Protection Study	• No developer action needed	N/A
SIS Report Preparation	• Often developers are required to correct missing documentation and are given 10 business days to do so, with 10 business days given where a correction is needed	**+20 business days** (or more)
<u>Total Time in SIS Process Timeline Outside of the Companies' Control</u>		• **+305 business days** (for projects with LVR) which equates to **438 calendar days** • **+170 business days** (for projects without LVR impact) which equates to **237 calendar days**

Q. PLEASE SUMMARIZE THE DISTRIBUTION-CONNECTED SIS TIMELINE ABOVE.

A. As can be seen, the actions that are outside of the Companies' control for projects with LVR impacts (including common extension periods) can total as many as 305 business days, which is equivalent to approximately 445 calendar days. The actions that are outside of the Companies' control for projects without LVR impacts (including common extension periods) can total as many as 170 business days, which is equivalent to 245 calendar days.

These examples highlight how overly simplistic it is to assert that the Companies are solely at fault for developers' business challenges associated with delays in the interconnection process. In fact, in some cases, the Companies may be meeting the SIS target timeline when waiting times for Interconnection Customer decisions, for example, are excluded from the completion time requirements in. (*See* NC Procedures, Att. 7, ¶ 18) As described above, the extensive time periods that relate to developer actions can often constitute a majority of the SIS timeline for many projects.

Once again, the timeline dates specified above are generic and every project will differ. There are developers that are more timely in providing information than others and, in those cases, the portion of the timeline within developer's control is reduced. But it is also true that there are developers that are more egregious in requesting extensions, requiring cure periods and challenging the Companies' technical conclusions. Other developers may also have less technical expertise or understanding of the Companies' requirements and therefore, require more guidance from the Companies in providing appropriate documentation, etc.

Finally, as the Companies have previously described, the available capacity of the distribution and transmission system (capacity that was paid for by retail customers) is increasingly being consumed due to the high penetration levels of installed utility-scale solar across the Companies' systems, especially in DEP-East. As a result, it will become increasingly common for projects to require significant distribution or transmission system Upgrades to interconnect, the cost of which may render projects financially infeasible. DEC/DEP witness Gajda addresses this issue in greater detail in his rebuttal testimony.

The Companies' expectation (which has been borne out anecdotally by recent experience) is that developers will more frequently seek to challenge the Companies' technical conclusions and delay decisions where they perceive the available interconnection options may render their development project uneconomic. Simply put, where a developer's only viable option is withdrawal, many developers will exhaust every conceivable avenue of challenge (whether expressly provided for under the NC Procedures or not) before accepting withdrawal.

Q. HOW DOES THE ABOVE TIMELINE IMPACT THE INTERCONNECTION QUEUE?

A. Given all of the factors discussed above that are outside of the Companies' control, the timeline for completing a SIS for a distribution-connected project can easily approach a year in duration or more. Given the unparalleled volume of utility-scale solar generating facilities requesting to interconnect to the Companies distribution systems and the practical impact of the interdependency queuing process, uniquely long interconnection processing times are unsurprising. To put it in simple terms, if there are 10 projects seeking to interconnect to the same substation, the 10th project will not be studied until the Company has processed the first 8 projects. If the SIS process for a single project takes a year or more, the unavoidable reality is that the 10th project will likely remain un-studied in the queue for an extensive period of time.

Q. PLEASE DISCUSS THE INTERSECTION OF THIS SIS TIMELINE AND THE UNPARALLELED AMOUNT OF DISTRIBUTION-CONNECTED SOLAR FACILITIES IN NORTH CAROLINA.

A. Since 2011, over 1,100 utility-scale solar projects (greater than 1 MW) have sought interconnection to the Companies' distribution system, of which over 750 were between 4 and 5 MW. Of these 1,100 projects, about 400 have been connected, over 500 have either withdrawn or were canceled and over 200 are currently in the interconnection process. This amount of utility-scale distribution-connected projects is simply unparalleled in the entire country.

In many cases, these projects sought to interconnect to the same substations and distribution feeders in certain rural areas of the state. This results in many projects being designated as "interdependent" and therefore, placed "on hold" until earlier-queued projects seeking to interconnect to the same substation or distribution feeder complete the interconnection process.

As discussed above, when a later-queued project is placed on hold behind two other earlier-queued Interconnection Customers due to interdependency, such project cannot, under the terms of the NC Procedures, proceed to SIS until the earlier-queued projects are processed.

However, given that the SIS timeline can take up to a year and often longer—a substantial portion of which is not in the Companies' control—it is unsurprising that many projects would remain on hold for extended periods of time.

This outcome is not due to any failure on the part of the Companies, but, instead, has primarily resulted from the unprecedented amount of utility-scale solar projects seeking to interconnect to the Companies' distribution system. Short of eliminating significant portions of the distribution study process (which would not be in accordance with Good Utility Practice), there is simply no "silver bullet" solution to expediting the distribution study process, particularly where many such projects have sought to interconnect to the same substations and feeders.

Q. PLEASE DISCUSS HOW THE SIS PROCESS HAS EVOLVED OVER TIME.

A. As the SIS process has evolved over time, many practices have developed that have lengthened the study process. These practices include mitigation options, developer-requested extensions, cure periods, and informal information requests and challenges.

Q. PLEASE DESCRIBE THE IMPACT THAT THE MITIGATION OPTION PROCESS HAS ON THE SIS TIMELINE.

A. The mitigation option process is not contemplated by the NC Procedures, but was introduced by the Companies in late 2016 as a concession to provide alternative project size options for developers to select where the system impact of the generating facility reflected in the Interconnection Request was likely uneconomic due to the limited availability of distribution or network capacity. Rather than simply studying an Interconnection Request as submitted (which is all that is required under the NC Procedures), the Companies conduct additional analysis to provide a preliminary cost assessment of alternative project configurations. Providing such alternative options necessitates additional studies and therefore lengthens the study process and delays the study of later-queued projects. As shown above, the mitigation option evaluation and Interconnection Customer decision making process has the potential to increase the SIS timeline by 75 business days (approximately 109 calendar days), even without accounting for the impact of formal and informal disputes and information requests.

The Companies do not necessarily oppose the mitigation option process (and, in fact, have committed to provide mitigation option to certain QF standard offer projects covered under the Nameplate Settlement, as filed with the Commission on February 2, 2018), but the unavoidable result is that each additional component or practice that is layered into the SIS process will necessarily lengthen the study period and impact other projects.

Q. PLEASE DESCRIBE THE IMPACT THAT DEVELOPER-REQUESTED EXTENSIONS HAVE ON THE SIS TIMELINE.

A. As is described above, it is very common for developers to request and be granted extensions in connection with LVR options, mitigation options, transformer data provision and document correction. Such extensions prolongs the study period and can often impact other projects.

Q. PLEASE DISCUSS THE IMPACT THAT CURE PERIODS HAVE ON THE STUDY PROCESS TIMELINE.

A. The Companies have historically informally provided Interconnection Customers "cure periods" for missed deadlines in a number of circumstances during the SIS process, even though not expressly required under the NC Procedures. For example, where an Interconnection Customer fails to respond to a mitigation options communication within the timeframe specified, the Companies' assigned account manager will send a follow up communication in writing to provide the Interconnection Customer a cure opportunity before completing the SIS based upon the originally-requested size of the generating facility. These cure periods delay the interconnection process for projects and, in many cases, have an adverse impact on later-queued projects.

In the interest of expediting the overall study process, the Companies could seek to eliminate cure periods where not expressly required under the terms of the NC Procedures. However, such a practice would undoubtedly be met with strong opposition by Interconnection Customer who would object to being withdrawn for failure to adhere to the specified deadlines. Accordingly, the Companies' modifications to the NC Procedures propose to memorialize a single 10 Business Day cure period during both the Facilities Study and the System Impact study processes in the event that an Interconnection Customer fails to respond to a request of the Utility.

Q. PLEASE DISCUSS THE IMPACT OF INFORMATION REQUESTS AND INFORMAL DISPUTES ON THE SIS TIMELINE?

A. In many cases, developers seek to engage in protracted dialogue and informal discovery concerning the Companies' technical analysis or cost estimates where the developers disagree with the Companies' conclusions. While the Companies are committed to making reasonable efforts to provide information to developers concerning the Companies' study methodologies and the particular factors impacting the results of interconnection studies, the reality is that protracted engagement beyond that which is contemplated in the NC Procedures diverts substantial resources from the study efforts for other projects. In short, this type of engagement inevitably delays the interconnection process.

Q. PLEASE DESCRIBE THE IMPACT OF NOTICES OF DISPUTE.

A. Similar to the extensions and cure periods discussed above, formal notices of dispute pursuant to the NC Procedures impacts other projects and siphon resources away from the study process. The Companies are certainly not arguing that the right to file notices of dispute should be eliminated but are observing that such disputes will inevitably and unavoidably impact other projects and are yet another factor outside of the Companies' control that contribute to long queue periods. For instance, witness Riggins described in his direct testimony a particular project that refused to select a mitigation option. That same Interconnection Customer also filed a notice of dispute, which further extended the SIS process, and then was ultimately withdrawn after failing to comply with the NC Procedures. In total, the actions of the developer delayed the interconnection process at the SIS step for more than a year from the point in time that the mitigation options were delivered until the project was withdrawn.

Importantly, there were also several later-queued projects that were interdependent on the project described above, and such projects remained "on hold" throughout the entire year+ process described above. Those interdependent projects were undoubtedly frustrated that they have remained on hold for an extensive period of time. And yet, the reality is that this year+ delay was completely outside of the Companies' control.

Q. PLEASE DESCRIBE THE "CATCH-22" THE COMPANIES OFTEN FIND THEMSELVES IN WITH RESPECT TO ENGAGEMENT WITH DEVELOPERS IN THE INTERCONNECTION PROCESS.

A. When dissatisfied with the interconnection options made available by the Companies in accordance with Good Utility Practice, many developers will take every conceivable action to obtain a different outcome, which will necessarily prolong the process. While the Companies certainly understand the financial factors driving developers to take such actions, the reality is that such strategies consume utility management and engineering resources and invariably delay other projects seeking to complete the interconnection process.

The "catch-22" arises because where the Companies seeks to require particular developers to adhere to rigid timelines, it is often challenged by the particular developer. But where the Company does not strictly enforce rigid timelines, it impacts other developers who, in turn, complain about the general delays in the interconnection process.

A good example of this "catch-22" is the mitigation option process timeline. As described above, the mitigation option process prolongs the SIS timeline. Moreover, in many cases, developers have refused to select mitigation options in a timely manner. Therefore, the Companies have sought to impose reasonable deadlines for developers to respond to mitigation options. In one case, a particular developer filed a notice of dispute challenging the Companies' ability to impose a reasonable deadline on the Interconnection Customer's selection of a mitigation option. Separately, that same developer also informally complained to DEP regarding delays in studying another project owned by that developer but such delay was driven largely by an earlier-queued project owned by a separate developer that similarly refused to select a mitigation option within the prescribed timeline. In other words, developers pursue strategies to maximize opportunities for their projects but then complain when those same strategies have an adverse impact on their own projects.

Q. DISCUSS THE CHALLENGES OF CONSIDERING ONE-OFF TECHNICAL SOLUTIONS

A. In many cases, developers have requested that the Companies consider particular one-off, non-standard technical solutions in evaluating the system impacts of their proposed generating facility Interconnection Request. As discussed in greater detail by DEC/DEP witness Gajda, accommodating utility-scale generating facilities with non-standard methods shifts cost and reliability risk to the Companies' retail load customers and can become unsustainable and incompatible with the Companies' obligation to plan and operate the system in a safe and reliable manner for all customers. In general, engaging in "one-off" solutions is simply not a sustainable practice in light of the volume of pending Interconnection Requests. For the reasons I discus above, even engaging in the often-protracted discussions regarding an Interconnection Customer's desire for the Companies to restudy a custom non-standard solution to reduce the developer's Upgrade cost or to increase the capacity that can interconnect to the Companies' system at a given location can add additional significant extensions to the interconnection process.

Q. PLEASE SUMMARIZE THE COMPANIES' COMMENTS ON THE DISTRIBUTION STUDY PROCESS.

A. In summary, the distribution study process of utility-scale solar projects in North Carolina is a complex undertaking and the timeline for such process is significantly impacted by factors outside of the Companies' control.

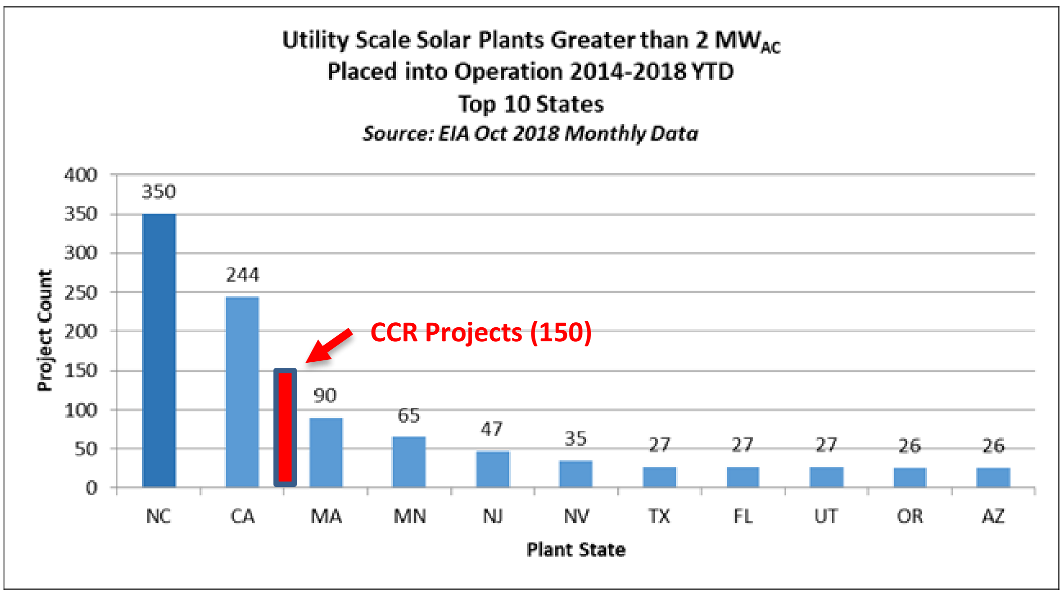
As described in the testimony of DEC/DEP witness Riggins, the Companies have exerted tremendous efforts to increase resources and improve processes to expedite the study of projects and has achieved nation-leading successes. And the Companies are not asserting that no extensions should be granted or cure periods allowed or informal exchanges of information permitted. Nor are the Companies asserting that they have, in every instance, processed every Interconnection Request in the most efficient way possible or that there are no instances in which administrative inefficiencies have contributed to delayed study processes. But it is critical that the Commission understand the extent to which current study delays and long queue wait times are substantially impacted by factors outside of the Companies' control.

Q. NCCEBA WITNESS NORQUAL SPECIFICALLY CRITICIZES THE DELAYS IN THE INTERCONNECTION PROCESS. PLEASE RESPOND.

A. An examination of some data related to CCR's development activities and the Companies' processing CCR Interconnection Requests provides a good case study of both the dramatic successes of the Companies as well as the complexities of the interconnection process.

Based on a combination of data provided by CCR and the Companies' records, the Companies have interconnected over 150 CCR- and affiliate-developed projects totaling more than 1,250 MW since 2014. To put this into perspective, this means that the Companies have processed, studied, engineered, constructed, and completed more utility-scale solar generator interconnections for a single developer—CCR—over the last 5 years ***than has been interconnected in total for every other state in the country with the exception of California***. Below, I have updated Figure 3 from my direct testimony to illustrate how the CCR projects interconnected in North Carolina compares to the top 10 utility-scale solar states in the country during the period 2014-2018.

Updated Figure 3



These facts undeniably demonstrate the Companies' significant good faith efforts to support CCR's solar generator Interconnection Request processing.

Q. DOES WITNESS NORQUAL ACKNOWLEDGE THE ASPECTS OF THE INTERCONNECTION PROCESS THAT ARE OUTSIDE OF THE CONTROL OF THE COMPANIES AS DESCRIBED ABOVE?

A. No. CCR witness Norqual fails to acknowledge the many factors impacting the interconnection process that are outside of the Companies' control. These factors have had a direct impact on the timeline for every CCR Interconnection Request.

Q. EARLIER IN YOUR TESTIMONY YOU DISCUSSED THE IMPACT OF INTERDEPENDENCY ON INTERCONNECTION TIMELINES. CAN YOU SPECIFICALLY DESCRIBE A CCR PROJECT THAT HAS EXPERIENCED INTERCONNECTION DELAYS DUE TO INTERDEPENDENCY?

A. Yes, one CCR project in DEP has been designated interdependent and "on hold" for approximately 1,450 days, or almost four years. However, the reason for this significant time in queue is that the project sought interconnection on DEP's Weatherspoon 230 kV substation behind 13 other utility-scale solar projects already in the Companies' queue. DEP has diligently sought to interconnect the earlier queued projects and as of today, six of these earlier-queued solar projects totaling approximately 26 MW have now been interconnected. But given the SIS study timeline described above (not to mention the time required to complete FSA, execute an FSA and receive payment), it is no surprise that such project has remained in the queue for an extended period. This "delay" does not reflect any fundamental flaw in the Companies' interconnection process but instead is an inevitable product of the interdependency of projects all locating in the same area and on the same circuit or substation.

Q. WHY HAVE YOU FOCUSED ON THE SIS TIMELINE FOR DISTRIBUTION-CONNECTED PROJECTS?

A. Distribution-connected projects constitute the vast majority of the utility-scale solar projects that have been interconnected (approximately 93%) and the vast majority of the utility-scale solar projects that remain in the queue (approximately 71%). Therefore, understanding the SIS timeline for distribution-connected project is critical to assessing the factors driving the current interconnection wait times.

Q. PLEASE COMMENT ON THE SIS TIMELINE FOR TRANSMISSION-CONNECTED PROJECTS.

A. As the Companies have previously explained, the amount of distribution-connected solar in North Carolina is unparalleled and these penetration levels give rise to a wide range of technical considerations and costs in connection with the interconnection. In contrast, there tends to be fewer factors impacting transmission-connected generation and where transmission network constraints arise, they tend to involve substantial expense that result in voluntary withdrawal within the established timelines. Nevertheless, there have been many instances in which developer actions have delayed the study process for transmission-connected projects and, once again, the Companies expect delays to increase as more substantial upgrades are triggered.

Q. ASIDE FROM THE SIS PROCESS, WHAT ARE THE OTHER MAJOR COMPONENTS OF THE INTERCONNECTION PROCESS?

A. The other major components of the interconnection process are the Facilities Study including the field engineering design work, the construction process, the inspection and commissioning process.

Q. PLEASE DESCRIBE HOW THOSE PROCESSES CAN ALSO BE TIME-CONSUMING.

A. The Facilities Study includes any final modeling requirements, but most importantly for distribution projects, includes the field engineering design work and development of the construction work order and more detailed cost estimates. So, for example an engineer might require several weeks to confirm existing right of way easements, obtain property owner approval for any pole line changes, obtain any new right of way, submit highway and in many cases rail road encroachment permits in addition to normal design, construction drawings, and work order estimates. For transmission projects these functions can take many months.

The construction process can be very complex, particularly in the increasingly common scenarios where projects are triggering large distribution upgrades or transmission network upgrades. For example, distribution upgrade costs in many cases have exceeded $1M and require a half year or more to complete. Transmission network upgrade costs are now being seen in the $10-$40M, and in one case will exceed $100M. The construction process can be delayed by challenges ranging from complex line outage restrictions to more mundane weather conditions. For examples, one recent distribution-connected project was delayed for months where a pole line crossing a land-owner's property could not be accessed because of rainy weather and the land-owner would not allow construction equipment on their property until his land dried out.

Q. HOW WILL HB 589 IMPACT THE INTERCONNECTION PROCESS.

A. HB 589 marked an important transition in the state's renewable procurement strategies away from standard offer contracts that incented a surging and unparalleled growth of 5 MW distribution-connected projects and towards a competitive procurement process that is expected to result in the selection of larger, transmission-connected projects.

In the long-term, from an interconnection process perspective, this transition is expected to result in more efficient interconnection practices and will tend to minimize upgrade costs by selecting projects that are located in favorable grid locations.

In simple terms, it is much easier to study and interconnect a single cost-effective 80 MW transmission-connected project identified through CPRE than it would be to study and interconnect 16 distribution-connected 5 MW projects, each of which must be carefully studied to ensure neighboring customers also interconnected to the same distribution circuits are not impacted by this large generator cycling on and off regularly.

Q. ARE THERE REMAINING CHALLENGES IN THE SHORT TERM?

A. Undoubtedly, yes. That is because there are currently approximately 224 projects greater than 1 MW seeking distribution interconnection that must be studied to support their safe and reliable interconnection. In addition, as was described in my pre-filed direct testimony, the currently interconnected generation has consumed substantial amounts of the available distribution and transmission capacity and, as a result, projects currently seeking to interconnect are increasingly triggering the need to make substantial Upgrades, including the need for major transmission network upgrades. These more significant Upgrades often require substantial engineering and construction resources, further delaying interconnection. In my direct testimony, I specifically identified a major transmission upgrade that has already been triggered and will take 3-4 years to construct and will delay the interconnection of numerous other projects located in that specific geographic area.

Once again, the delays that projects may experience due to the substantial construction projects required to further expand the Companies' network are not a product of any administrative or processing inefficiencies on the part of the Companies but instead are simply a result of the unparalleled growth of interconnected solar generation on the Companies' systems.

Given the amount of remaining distribution-connected projects that must complete the SIS timeline described above, combined with the growing congestion issues and associated construction challenges, there remain significant hurdles to the completion of the transition from North Carolina's legacy PURPA implementation to the new policy direction reflected in HB 589.

Q. WHAT IS A GROUPING STUDY?

A. A grouping study gathers multiple interconnection requests that are submitted within a defined request window into a single group or cluster. Unlike the current serial process, where interconnection requests are generally studied in sequence based on the time the interconnection request is submitted, a grouping study allows projects to be studied at the same time. To be effective, the grouping study needs to allocate upgrade costs to all projects that contribute to the need for the upgrade, and will require early financial commitments to fund these upgrades. Grouping studies are successfully being used in other parts of the country to manage high volumes of interconnection requests.

Q. PLEASE DESCRIBE THE GROUPING STUDY THAT WAS APPROVED FOR PURPOSES OF CPRE.

A. In the October 5, 2018 *Order Approving Interim Modifications to North Carolina Connection Procedures for Tranche 1 of CPRE RFP*, the

Commission approved modifications to Section 4.3.4 of the NC Procedures, amongst others, to facilitate a grouping study for the limited purposes of implementing CPRE. In this case, grouping studies will be used to establish a study "base line" for non-participating projects and then competitive participating projects are grouped to form a study "change case" to assign upgrade costs and further evaluate bids to determine the least total cost of a portfolio of projects.

Q. WHY DOES THE COMPANY BELIEVE THAT GROUPING STUDIES FOR THE ENTIRE INTERCONNECTION QUEUE WOULD BE BENEFICIAL?

A. Grouping studies will make the interconnection process more efficient from a transmission-level perspective and will allow costly transmission network upgrades to be allocated to multiple projects rather than burdening individual projects with the entire upgrade costs. Distribution-connected projects would also be included in these grouping studies, where the studies would more quickly or efficiently determine their impact on the transmission network. Network upgrade costs would also be allocated to these projects if needed, but studies to determine distribution upgrade costs most likely would remain in a sequential process, or limited/local grouping studies.

Q. WHAT OTHER UTILITIES UTILIZE GROUPING STUDIES IN THIS WAY?

A. Public Service Company of New Mexico, Midcontinent Independent System Operator, Inc. ("MISO"), Southwest Power Pool, Inc. ("SPP") and California Independent System Operator Corp. (CAISO") and other FERC jurisdictional RTOs have implemented grouping studies. On November 19, 2019, Public Service Company of Colorado ("PSCO") filed a proposal to move from a "…first-come, first served model…to a first-ready, first-served model. PSCO proposed to move to grouping studies in response to "[s]urges in the volume of new generation development" that were making it difficult to process Interconnection Requests in a timely manner. PSCO has a queue containing 23,000MW where their peak load is only 8,500MW. In its 2008 Technical Conference Order regarding Interconnection Queuing Practices, FERC suggested that grouping studies or first-ready, first-served interconnection process could speed up queue processing.

Q. PLEASE DISCUSS THE COMPANIES' SPECIFIC PLANS TO MOVE TOWARDS A FULL GROUPING STUDY, INCLUDING TARGET DATES FOR ITS ACTIONS?

A. The Companies are committed to an extensive stakeholder engagement process beginning in the first quarter of 2019 and are in the process of developing a strawman proposal that will be used as a starting point for the stakeholder process. The Companies envision an iterative process that allows for multiple meetings with stakeholders with a goal to complete the stakeholder process by late June 2019 which would result in redline changes to the State and Federal interconnection procedures. The Companies would then make a filing of the proposed changes in July 2019 to both the FERC and the NCUC. This process will also need to include South Carolina stakeholders and will likely include a filing with the South Carolina Public Service Commission since the transmission network is agnostic to state lines.

Q. IS THE GROUPING STUDY A PANACEA FOR THE CURRENT INTERCONNECTION QUEUE?

A. No. As currently contemplated, the grouping study will only assess the transmission impacts of both distribution- and transmission-connected projects, and will not assess the distribution level impacts of distribution-connected projects. As discussed above, the current interconnection queue still contains a backlog of proposed utility-scale distribution-connected projects, and there is no "quick fix" for processing such projects. Each project must undergo the distribution-level study process described above to ensure a safe and reliable interconnection

. However, assuming that the state policy reflected in HB 589 is carried forward into the future, the Companies expectation is that the majority of future procurement efforts will occur via competitive RFP processes that will most likely encourage the development of larger, transmission connected projects that can be more efficiently studied through a grouping study process.

Q. PUBLIC STAFF WITNESS LUCAS RECOMMENDS THE COMPANIES INITIATE A "STAKEHOLDER DISCUSSION FOCUSED SOLELY ON REVISITING THE PROJECT A/B PROCESS AND THE OPTIONAL GROUPING STUDY PROCESS TO DETERMINE HOW THEY MIGHT BE USED TOGETHER TO MORE EFFICIENTLY MANAGE THE LARGE NUMBER OF PROJECTS IN THE QUEUE." PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION.

A. As discussed above, the Companies believe that a grouping study will be a useful tool for expediting certain portions of the interconnection study process. The Commission should allow the Companies to implement the steps described above rather than adopting Public Staff's recommended stakeholder and reporting requirements at this time.

Q. PUBLIC STAFF WITNESS LUCAS ALSO IDENTIFIES "CONCERNS THAT RAISE SERIOUS QUESTIONS ABOUT THE FAIRNESS AND EQUITY REGARDING COST RESPONSIBILITY FOR USERS OF THE GRID, WHETHER THEY ARE DGS INJECTING ENERGY OR CONSUMERS EXTRACTING ENERGY." PLEASE RESPOND TO THESE CONCERNS.

A. The Company shares these concerns and agrees that care should be taken to assign costs to the "cost causer" and minimize the risk of cost shifting. However, the Companies also recognize that there are challenges to preventing all cost shifting and that it is nearly impossible to recover all interconnection processing costs that vary over time through fixed fees applied to a number of projects that can also vary over time. Also, post-interconnection, the Companies are seeing a growing number of customer calls dealing with, for example, net metering billing questions and questions about their solar facility performance for which there is no cost recovery mechanism for these costs other than to include in retail base rates.

Q. PUBLIC STAFF WITNESS WILLIAMSON RECOMMENDS AN INDEPENDENT REVIEW OF THE ENTIRE NORTH CAROLINA INTERCONNECTION PROCESS. PLEASE RESPOND TO SUCH RECOMMENDATION.

A. Public Staff witness Williamson is correct that the Companies remain willing to consider an "EPRI or a similar third-party to assist in studying and further developing North Carolina's Fast Track and other technical interconnection screens." Witness Gajda provides additional explanation on this proposal in his rebuttal testimony, recommending that the Companies' Technical Standards Review Group would provide an appropriate forum for such discussions with EPRI or a similar third-party. However, a third-party audit of the entire interconnection process would be an undertaking on an entirely different scale and the Companies do not believe such an enormous effort would be an appropriate or efficient use of the Companies' resources at this time, particularly as the Companies direct their efforts to implementation of a stakeholder process recommending a transition to a full grouping study. Also, many of these same resources need to remain focused on processing interconnection requests.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BY MR. JIRAK:

Q Mr. Freeman, do you have a summary of your testimony?

A I do.

Q Would you please proceed with that?

(WHEREUPON, the summary of GARY R. FREEMAN is copied into the record as read from the witness stand.)

Testimony Summary - Gary Freeman

Docket No. E-100, Sub 101

January 28, 2019

Thank you, Mr. Chairman, Commissioners for allowing me to provide a summary of my testimony in this docket.

My direct testimony provides the commission with an overview of the companies' nation-leading efforts to interconnect utility-scale and smaller generating facilities to the grid. Data from the United States Government's Energy Information Administration demonstrates the remarkable and national-leading interconnection success of Duke.

For instance, the Companies' have connected more utility-scale solar facilities to the general distribution system than any other state in the country—including even California. And this success is even more stark when compared to other states in the top ten. For instance, the Companies have interconnected more than twice the number of projects as the third-leading state—Massachusetts—and more than thirteen times the highest ranking state in the south east. What is even more compelling is that, since 2015, the Companies have connected the highest number of greater than 2 MW solar plants in the entire country—with 225 successful interconnections, compared to 184 in California—the second leading state—and 59 in Massachusetts—the third leading state. During this period Duke has connected nine times more projects than the tenth leading state—Texas.

And these comparisons I have just described are even more remarkable when you take into account the relative size of the respective states and other factors. California is four times the size of NC in terms of population with 3 large utilities, Texas has three times the amount of population and Massachusetts is served by 4 different ~~IOUs~~ utilities. Viewed from a per-capita perspective, North Carolina's success is staggering.

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Both in this proceeding and in other public forums, Duke is often criticized for delays in the interconnection process. But the results that I have described completely contradict such criticisms. And the Companies' successes continued in 2018. In my direct testimony, I had projected 400-500 additional MW to be connected in 2018. I can now confirm that the companies successfully connected 537MW in 2018. And such significant amounts of interconnection were achieved despite the significant headwinds resulting from the diversion of construction and support resources for weeks at a time to support the historic hurricane damage caused by Florence and Michael. The Companies' also connected over 2900 net metering projects in 2018 compared to just over 1100 projects in 2017.

All of this success is a result of the tremendous efforts of a large team of dedicated and talented Duke personnel involving technical experts, account managers, study teams, engineering and construction personnel and more. My colleague Jeff Riggins will describe in more detail the substantial increase in personnel that the Companies have implemented to achieve this success. I am extremely proud of Duke's efforts in this respect and particularly proud of the ways in which we have continued to balance our dual obligations of achieving safe interconnections while also continuing to ensure consistent, reliable and quality power service to all customers, as is detailed in the testimony of my colleague John Gajda. The state of North Carolina is a "living laboratory" in that no other state has attempted to interconnect so much utility-scale solar projects to its distribution system. As the Companies have grappled with the long-term implications of this "first of its kind" issue, we have sought to implement reasonable, non-discriminatory policies to limit any adverse impacts on all of the Companies' customers and to ensure long-term sustainability.

Nevertheless, despite the Companies' successes, the interconnection queue remains high and now stands at over 13,000 of solar across NC and SC. We include SC in our queue numbers since the grid crosses state boundaries.

Furthermore, the amount of successfully interconnected solar generation is leading to congestion on the transmission system primarily caused by the large amount of solar generation proposing to connect in the SE portion of DEP and in the southern portion of DEC. As described in my testimony, as penetration levels increase, interconnecting additional generation located in remote areas of the grid and in increasing amounts in the same general area is becoming more challenging. As System Impact studies are now showing, there is a need to spend hundreds of millions of dollars to upgrade the transmission network to accommodate higher amounts of generation. The Companies are committed to working with solar developers to support these needed grid upgrades, but must do so within the guidelines and policies set forth by the state and the FERC.

In light of the continued growth in the interconnection queue, it has become clear that a more comprehensive change in the interconnection process is needed to address the queue, allocate increasing upgrade costs across many projects, and ensure that projects in the queue are truly ready to be connected to the grid. Duke is working to identify the needed changes and my testimony discussed some of the key next steps.

In my rebuttal testimony, I have also provided some additional background to help the Commission understand the complexity and challenges of the interconnection process. Many of these complexities and challenges contribute to long interconnection wait times and are outside of the control of Duke. Examples include growing interdependencies, awaiting decisions and information from projects, and the growing number of technical disputes challenging the companies Study conclusions. Therefore, general critiques of the interconnection queue wait times that fail to recognize the complexity of the process are misinformed at best and disingenuous at worst.

In this proceeding, the Companies are specifically seeking the Commission's approval of a number of modifications to the NC Procedures as are identified in the testimony of my colleague John Gajda. These changes should improve certain aspects of the study process and ensure that the Companies are, to the greatest extent possible, recovering its costs from the cost causers. As was reflected in our filing on Friday, the Public Staff, Dominion Energy North Carolina and Duke executed a stipulation that identified a full set of modifications that such parties support for adoption by the Commission. The stipulation also included certain specific modifications requested by the North Carolina Pork Council that are supported by the stipulating parties. To be clear, the stipulation simply formalizes for the benefit of the Commission what was already self-evident from the hundreds of pages of filings made in this proceeding—the fact that the Public Staff, DENC, and the Companies' were nearly fully aligned with respect to the modifications to the NC Procedures. In light of this stipulation and the record in this proceeding, we respectfully request the Commission's approval of the modifications identified in the stipulation.

In summary, Commissioners, I am proud of our nation leading success in interconnecting solar generation and I am confident that we will continue to tackle future challenges with the same level of determination and energy that has brought us this far. Duke is fully committed to the efficient study and processing of interconnection requests to its system while continuing to ensure that such interconnections do not adversely impact other customers and that future potential cost impacts of such interconnections are limited.

Commissioners, thank you for this opportunity to provide this summary.

MR. JIRAK: Thank you, Mr. Chairman.

DIRECT EXAMINATION BY MR. JIRAK:

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

A Yes. John W. Gajda. My business address is 3401 Hillsborough Street, Raleigh, North Carolina.

Q Mr. Gajda, by whom are you employed and in what capacity?

A Yes. I work in the System Operation Services Department of Duke Energy.

Q And did you cause to be prefiled in this docket on November 19, 2018, 65 pages of direct testimony in question and answer form along with one exhibit?

A Yes.

Q And do you have any changes or corrections that need to be made to that direct testimony at this time?

A Yes, I have one. Give me a moment.

Q Yes.

A The only change is stipulated in -- is located in my direct testimony on page 8, lines 5 and 6. And the text to be struck begins 2.2.1 and it says -- I'll just read the text to be stricken.

2.2.1 (clarifying when a Section 2 project will require Fast Track screening).

Q Thank you, Mr. Gajda. Aside from that correction, if I were to ask you the same questions that appear in your direct testimony today, subject to the correction you just described, would your answers be the same?

A Yes.

Q Mr. Gajda, did you also cause to be prefiled in this docket on January 8, 2019, 52 pages of rebuttal testimony in question and answer form, along with four exhibits?

A Yes.

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

A No.

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

A Yes.

MR. JIRAK: Mr. Chairman, at this time I would move that the prefiled direct and rebuttal testimonies of Mr. Gajda be copied into the record as if given orally from the stand, and that his direct and rebuttal exhibits be marked for identification as prefiled.

CHAIRMAN FINLEY: Mr. Gajda's direct prefiled testimony of 65 pages is 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. His rebuttal testimony of 52 pages is copied into the record as though given orally from the stand, and his four rebuttal exhibits are marked for identification as premarked in the filing.

MR. JIRAK: Thank you.

(WHEREUPON, Gajda Exhibit 1 is marked for identification as prefiled.)

(WHEREUPON, the prefiled direct testimony of JOHN W. GAJDA as corrected is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**DIRECT TESTIMONY OF**
Petition for Approval of Generator	)	**JOHN W. GAJDA**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Gajda, and my business address is 3401 Hillsborough Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?

A. I am on a Developmental Assignment for Duke Energy Corporation ("Duke Energy"), which is a type of "Special Projects" designation, working in the System Operations Services group.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I attained a Bachelor of Science degree in Electrical Engineering from the University of Arkansas in 1990, and a Master of Science degree in Electrical Engineering from North Carolina State University in 1994. From 2010 to 2014, I taught full or partial courses at North Carolina State University in Power Systems Analysis, System Protection, and Smart Power Distribution Systems, and since then offer occasional guest lectures in the Electrical and Computer Engineering Department. I have been a licensed Professional Engineer in North Carolina since 1996, and am also licensed in South Carolina and Florida. I am also a Senior Member of the Institute of Electrical and Electronics Engineers.

Q. PLEASE DESCRIBE YOUR ENGINEERING AND TECHNICAL BACKGROUND AND EXPERIENCE.

A. During the first eleven years of my career (1990-2001), I held several positions: as oilfield automation engineer for Conoco Oil Company (2 years); medium voltage motor control specification engineer for Siemens (1 year); Electric Systems Engineer for North Carolina Electrical Membership Cooperation ("NCEMC") (5 years), Project Manager/Engineer for Electrical Engineering Consulting & Testing, P.C. (2 years), and Utilities Engineer for the Public Staff of the North Carolina Utilities Commission (1 year). During my time at NCEMC, I was responsible for the design and implementation of several distribution & sub-transmission system protection and control projects related to the 15 MW Buxton Generating Station and the 3 MW Ocracoke Generating Station.

Since 2001, I have been employed by Duke Energy (and predecessor company Progress Energy), where I arrived as a mid-career entrant bringing experience primarily in system protection and generator interconnection and controls. I served in various roles in the Distribution Department from 2001 through 2013, where I have been increasingly responsible for providing technical direction and consultation within the Distribution Planning group, the Power Quality & Reliability group, and Distribution Standards. Significant projects I have worked on include: (1) in 2003, I designed and project managed the interconnection of a 3 MW landfill gas Generating Facility to a 12 kV distribution circuit in Progress Energy Florida (now Duke Energy Florida); (2) in 2005, I led a Progress Energy-wide training effort for field engineers focused on protective device coordination and distribution system protection; (3) in 2006, I authored a complete re-write of Progress Energy's Distribution Protective Coordination Manual; (4) during the period 2006 through 2009, I performed multiple interconnection studies, and completed project management and distribution interconnection for a 4 MW hydroelectric facility, a 3 MW landfill gas facility, and a 10 MW landfill gas facility to the Progress Energy Carolinas system; (5) from the period 2003 through 2012, I served as the primary technical resource to oversee all Progress Energy Carolinas' distribution interconnection requests, whether small net-metered facilities or multi-megawatt generators; (6) in 2008, I co-authored a paper titled "Distributed Generation Intertie With Advanced Recloser Control," which I presented at the 2008 Georgia Tech Relay Conference and which additionally formed the basis for Progress Energy's standard interconnection design; (7) in 2012, I performed an analysis of the planning limits for the Progress Energy Carolinas' standard distribution circuit design, and designed alternative construction methods to increase circuit capacity by over 50%.

During 2013-2014, I served as Lead Engineer in the Protection & Controls Engineering group within the Transmission department, where I was responsible for engineer oversight and re-design of relay settings philosophies for DEP's mobile substation fleet.

From 2014 through 2018, I served as Manager/Director of Distributed Energy Resources ("DER") Technical Standards within the

Distribution Energy Resources department, where I was responsible for development and refinement of new technical standards related to interconnection and integration of DER into the Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC" and, together with DEP, the "Companies" or the "Duke Utilities") systems in North Carolina and South Carolina. Since mid-July 2018, I have served in a technical consultation role within the System Operations Services department.

During my time at Duke Energy, I have been an active member in the development of IEEE 1547.7-2013 (IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection), and of IEEE 1547-2018 (IEEE Standard for Interconnection and Interoperability of DER with Associated Electric Power Systems Interfaces).

In 2018 I led the initiation of the Duke Energy DER Technical Standards Review Group ("TSRG"), designed as a forum for Duke Energy engineers and DER facility engineers to discuss Duke Energy technical policies surrounding interconnection, as well as technical and technology developments in DER interconnection. This group has now met three times for all-day sessions on the following dates: April 11, 2018; July 19, 2018; and on October 23-24, 2018.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current role, I provide internal technical consultation related to FERC Order 845 compliance, and lead Duke Energy's involvement in the new

IEEE P2800 Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems. I secondarily also remain an internal consultant on technical matters related to generator interconnection to the transmission and/or distribution system.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes, although only in my prior capacity as an engineer working in the Electric Division of the Public Staff. As I recall I had brief testimonies on three occasions: January 8, 2001, in Dockets E-43, Sub 2, and E-48, Sub 4; May 7, 2001, in Docket E-2, Sub 780; and May 9, 2001, in Docket E-43, Sub 2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the Companies' proposed modifications to the currently-approved North Carolina Interconnection Procedures ("NC Procedures"). I begin by providing a technical perspective on Duke Energy's interconnection efforts and challenges faced over the past few years. I next discuss my and the Duke Energy team's participation in the recent Advanced Energy ("AE")-led interconnection stakeholder process that was held during the summer and fall of 2017 ("2017 Stakeholder Process"). I also support the Companies' proposed limited modifications to the currently-approved Section 3 Fast Track and Supplemental Review process, and explain why the Companies do not support the major overhaul to this Section advocated for by the Interstate Renewable Energy Council ("IREC") and certain other parties during the recent AE-led stakeholder process. Overall, the Companies see limited structural issues within the technical evaluation portions of the NC Procedures, and do not believe that extensive revisions are necessary at this time. Last, I discuss the Companies' ongoing efforts to foster greater transparency and improved technical understanding of the Companies' evolving interconnection standards and technical requirements, including through the recent formation of the Duke Energy-led TSRG.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes, DEC/DEP Exhibit JWG-1 to my testimony is an updated version of the "Joint Utilities Redline" of the NC Procedures previously filed on March 12, 2018, by the Companies as well as Dominion Energy North Carolina ("Dominion"). This updated NC Procedures Redline tracks changes to the "current" NC Procedures, which includes the Interim Modifications to the NC Procedures approved by the Commission in its October 5, 2018 order filed in this docket.

Q. ARE THE COMPANIES PROPOSING ANY "NEW" MODIFICATIONS TO THE NC PROCEDURES OTHER THAN THOSE INCLUDED IN THE MARCH 12, 2018 JOINT UTILITIES REDLINE?

A. Yes. The Companies' redline to the NC Procedures contains several additional modifications to the NC Procedures that largely clarify existing provisions. Specifically, these modifications are to NC Procedures Sections 1.8.3.2 (clarifying timing of scoping meetings for interdependent Interconnection Customers), 2.2.1 (clarifying when a Section 2 project will require Fast Track screening), 3.1 (allowing utility and Interconnection Customer to mutually agree to Fast Track evaluation); 3.2 (clarifying that interdependency applies to Section 3 Interconnection Requests), 3.4.1.3 (clarifying that a Facility Study may be required for projects approved in Supplemental Review), 6.2 (establishing timeframes for concluding informal dispute resolution process), and 6.5 (establishing post-commissioning inspections). The Companies are also adding detail in the Interconnection Request forms included in the NC Procedures as Attachment 2 and Attachment 6 to allow Interconnection Customers to designate whether the Generating Facility is either customer-owned or leased from an electric generator lessor.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR DIRECT TESTIMONY.

A. I have divided my Direct Testimony into the following sections:

SECTION I: NORTH CAROLINA'S INTERCONNECTION LANDSCAPE AND THE 2017 STAKEHOLDER PROCESS

Q. BEFORE TURNING TO DUKE ENERGY'S PROPOSED MODIFICATIONS TO THE NC PROCEDURES, PLEASE PROVIDE THE COMMISSION YOUR TECHNICAL PERSPECTIVE ON NORTH CAROLINA'S UNIQUE INTERCONNECTION LANDSCAPE SINCE THE COMMISSION LAST CONSIDERED REVISIONS TO THE NC PROCEDURES IN THE SPRING OF 2015.

A. Witnesses Gary R. Freeman and Jeffrey R. Riggins provide a more general overview of North Carolina's unique interconnection landscape as well as Duke Energy's efforts to manage the interconnection process in response to the recent unparalleled development of utility-scale solar Generating Facilities proposing to interconnect to the Companies' distribution system and, increasingly, transmission system in North Carolina. My perspective is more technical in nature and reflects the engineering philosophy the Companies have applied in implementing Duke Energy's technical standards related to interconnection of DER.

North Carolina continues to experience unparalleled growth in utility-scale solar facilities seeking to interconnect to the Companies' systems that exceeds the pace of growth in nearly every other state in the country. Beginning before the May 2015 revisions to the NC Procedures, independent power producers developing qualifying facility ("QF") multi-megawatt Generating Facilities began to enter the Companies' interconnection queues in historic and unparalleled numbers. As of October 2018, there are 1,878 MW of distribution-connected DER operating in DEP and DEC. Specifically, over 94% of this capacity (1,772 MW) is represented by QF power-purchase type (non-net metered) Generating Facilities greater than 1 MW in size. Most of these multi-megawatt DER facilities are distribution-connected and 5 MW_{AC} in size. In DEP alone, as of October 2018, there are over 290 Generating Facilities greater than 1 MW (totaling over 1300 MW), interconnected to the DEP distribution system.

Nearly all of these QF generators are interconnecting to rural distribution circuits and substations. At the circuit level, a single 5 MW facility can consume anywhere between 25% to 70% of the capacity of a distribution circuit. At the substation level, a growing number of rural substations, especially in DEP, are hosting unprecedented levels of unplanned QF solar. For example, DEP substations such as the Henderson East 230 kV substation located in Vance County and the Fairmont 115 kV substation located in Robeson County are now completely "stacked" with utility-scale QF solar that has been interconnected over the past few years. These substations are now at or quickly approaching their capability to safely and reliably interconnect additional Generating Facilities.

Figure 1: Installed Utility-Scale QF Solar on Henderson East 230 kV Substation

DEP Substation	**Solar QF Installed kW**	**Date Installed**	**Aggregate Installed kW**
Henderson East 230 kV	4975	8/12/2013	4975
Henderson East 230 kV	3000	3/19/2014	7975
Henderson East 230 kV	4990	12/12/2014	12965
Henderson East 230 kV	5000	5/14/2015	17965
Henderson East 230 kV	5000	8/20/2015	22965
Henderson East 230 kV	4998	1/5/2016	27963
Henderson East 230 kV	5000	11/22/2016	**32963**

Figure 2: Installed Utility-Scale QF Solar on Fairmont 115 kV Substation

DEP Substation	**Solar QF Installed kW**	**Date Installed**	**Aggregate Installed kW**
Fairmont 115 kV	3500	11/13/2012	3500
Fairmont 115 kV	4320	12/10/2013	7820
Fairmont 115 kV	5000	8/6/2014	12820
Fairmont 115 kV	4999	8/22/2015	17819
Fairmont 115 kV	4999	8/3/2016	22818
Fairmont 115 kV	4999	10/12/2017	**27817**

Even more significantly, each of these substations also has additional utility-scale solar QFs in the DEP study queue requesting to interconnect. This unplanned and uncontrolled growth of new utility-scale QF Generating Facilities connected to the distribution system has resulted in a new power system phenomenon in North Carolina in which significant, variable, and intermittent reverse power flows are occurring on these and other circuits and substations across the DEP and DEC distribution systems. With solar Generating Facilities on distribution operating unscheduled and their output having no specific relation in time to the local load, the section of distribution circuit between the solar Generating Facility and its substation is increasingly operating similar to a transmission line, responsible for delivering the solar Generating Facility's energy to the substation and transmission system. This raises many questions about the future of utility distribution systems in North Carolina.

Q. IS NORTH CAROLINA'S INTERCONNECTION LANDSCAPE SIMILAR TO OTHER STATES'?

A. No, in my view, North Carolina's DER interconnection and distribution system landscape is significantly more complex than other states. In contrast to the Companies' experience, many utilities are just now starting to encounter small increments of utility-scale distributed generation (generally facilities above 1 MW_{AC}) being added to their distribution systems.

When PURPA was initially enacted in the late 1970s, and continuing until around 2010, interconnecting facilities of this large size—above 1 MW_{AC}—occurred rarely, with such projects being considered "special" and "unique" due to their large size. Today, these increasingly large, mostly 5 MW, Generating Facilities have become the "norm" in North Carolina, but not without difficulties. As I discuss later in my testimony, interconnecting these vast quantities of large, uncontrolled power export QF Generating Facilities to the distribution system has required new and evolving technical standards to mitigate the potential for localized power quality impacts and distribution system reliability risks, and to proactively manage potential future challenges in planning and operating the distribution and transmission system.

Q. PLEASE BRIEFLY PROVIDE AN OVERVIEW OF DUKE ENERGY'S PARTICIPATION IN THE 2017 STAKEHOLDER PROCESS, AND HIGHLIGHT YOUR ROLE IN THE PROCESS.

Advanced Energy facilitated the 2017 stakeholder process to review and discuss potential revisions to the NC Procedures. At the outset, AE organized four Working Groups, all of which the Companies actively participated in, along with other parties such as the Public Staff, Dominion, renewable energy developers, and numerous other stakeholders. These Working Groups were organized into four functional groups: (1) Interconnection Procedures, (2) New Technologies, (3) Studies & Screens, and (4) Queue Management, Certification of Generating Facilities.

Specifically, I led and facilitated Working Group meetings for two of the four working groups (Working Groups #3 and #4). In addition to AE's Working Groups, the Companies attended and sometimes arranged general stakeholder meetings over a period spanning more than six months. The groups covered a number of issues at varying levels of depth, including: (1) utility construction and design standards; (2) power quality monitoring and communications equipment; (3) the Fast Track and Supplemental Review process; (4) the potential reinsertion of an initial feasibility study into the Section 4 study process; (5) enhancements to the scoping meeting process; (6) interconnection study reporting; and, (7) optional cluster studies.

Q. IN YOUR VIEW, WAS THE 2017 STAKEHOLDER PROCESS BENEFICIAL?

A. Yes. This process was beneficial in providing a platform for constructive technical and policy discussions on necessary revisions to the NC Procedures. The 2017 Stakeholder Process also facilitated full or partial-consensus on a number of modifications to the NC Procedures.

SECTION II: OVERVIEW OF THE NORTH CAROLINA INTERCONNECTION STUDY PROCESS

Q. PLEASE PROVIDE AN OVERVIEW OF THE NORTH CAROLINA STUDY PROCESS FOR INTERCONNECTION PROJECTS, AND HOW PROJECTS OF DIFFERENT SIZES ARE HANDLED DIFFERENTLY.

A. The nature of DER interconnections can vary greatly based on facility size. The potential for system reliability or power quality impacts to the local distribution system or to other customers from interconnecting a 5 kW residential rooftop photovoltaic ("PV) installation will be inherently different than a 50 kW commercial rooftop PV installation, which will differ even further from that of a 5 MW solar Generating Facility. Correspondingly, the need for and appropriate level of review of each of these DER's resulting impacts on the distribution system differ greatly. Accordingly, the NC Procedures are designed to allow the utility to expend time and resources evaluating an Interconnection Request that are appropriate given to the interconnection's likely impact to the distribution system, which can and often does correlate directly to facility size. Through the NC Procedures, the utility is to determine how to interconnect the proposed Generating Facility while maintaining operational safety, reliability, and power quality, for the power system in the area of interconnection and the Companies' system as a whole. In order to make this determination, the NC Procedures contains several study processes that are, initially based on project size due to the reasons I mentioned earlier.

Q. PLEASE DESCRIBE THE SECTION 2 STUDY PROCESS CONTAINED IN THE NC PROCEDURES.

A. Section 2 of the NC Procedures provides an expedited process for Generating Facilities 20 kW or less, which are generally residential or small commercial facilities. This process is specifically called the "Optional 20 kW Inverter Process for Certified Inverter-Based Generating Facilities No Larger than 20 kW." Individually these installations often resemble the installation of a large appliance, and typically do not require specialized design by the utility to accommodate the interconnection. Therefore, this study process generally allows these small projects to proceed to interconnection relatively quickly.

Q. PLEASE EXPLAIN WHY THIS PROCESS IS LIMITED TO CERTIFIED INVERTER-BASED TECHNOLOGIES.

A. The NC Procedures recognize that certified inverter-based technology can be safely and reliably interconnected to the utility's system through a more expedited process. To be certified, the inverters are equipped with some industry-standard technical specifications such as Underwriters Laboratories' UL1741, which provide some assurance to the utility industry of proper grid interactive operation (like automatic shutdown when there is a loss of utility source).

Q. HOW ARE IMPACTS TO THE DISTRIBUTION SYSTEM FOR PROJECTS STUDIED UNDER THE SECTION 2 STUDY PROCESS DETERMINED?

A. Individually, Section 2 facilities are expected in many cases to have little impact to the distribution system, although when aggregated (*e.g.*, all homeowners on one service transformer installing solar), there is the potential for greater impact. The Companies undertake a technical screening process to evaluate these facilities for potential impacts to the distribution system. When a facility fails a technical screen and is determined to potentially impact the distribution system, the NC Procedures allows for these projects to be scrutinized further, under the Section 3 or Section 4 study process.

Q. YOU MENTIONED THE SECTION 3 STUDY PROCESS, CAN YOU EXPAND ON THIS STUDY PROCESS FOR THESE SMALLER SIZED FACILITIES?

A. Section 3 of the NC Procedures similarly provides for a more expedited study process for slightly larger projects, specifically called the "Optional Fast Track Process for Certified Generating Facilities." This process recognizes that projects between 20 kW and 2 MW in size may, depending upon their attributes, have few impacts to the surrounding utility system, and therefore should have an opportunity to move to interconnection with relative speed if lack of impact can be determined. However, if a facility proceeding through this study process is determined to possibly have some amount of impact, the Section 3.4 Supplemental Review process allows the facility to be studied further. Importantly, however, the Supplemental Review process allows these smaller facilities' impacts to undergo slight additional review without expending significant amounts of time in study, thereby allowing these facilities, which potentially require only interconnection facilities or minor modifications to the utility's system, to proceed to interconnection quickly.

Q. PREVIOUSLY YOU ALSO MENTIONED THE SECTION 4 STUDY PROCESS. CAN YOU BRIEFLY ELABORATE ON THIS PROCESS AND ITS APPLICATION TO SMALLER FACILITIES AS WELL?

A. Yes. Section 4 of the NC Procedures recognizes that when a finding of no significant impact cannot be well determined for "Section 2" or "Section 3" projects, a conventional or "full" interconnection study should be performed in order to determine potential system impacts and the need for system upgrades required to mitigate impacts identified through study. This type of study relies on further modeling, somewhat similar to the type of modeling a distribution planning engineer might do for a planning study, short circuit modeling and protective coordination analysis, along with voltage and thermal/loading modeling and analysis. I elaborate on this process further below.

Q. WHAT SIZE GENERATING FACILITIES ARE STUDIED FOR INTERCONNECTION UNDER THE SECTION 4 FULL STUDY PROCESS?

A. This process is applicable to Generating Facilities that are greater than 2 MW in size and planning to sell their full output to the utility to which it is interconnecting. However, facilities of any size that are not certified are also studied under this process, as well as facilities of any size that are certified but did not pass the Fast Track Process or the 20 kW Inverter Process.

SECTION III: FAST TRACK AND SUPPLEMENTAL REVIEW

Q. PLEASE EXPLAIN FURTHER HOW THE "FAST TRACK" AND "SUPPLEMENTAL REVIEW" SECTIONS OF THE NC PROCEDURES ARE DESIGNED AND HOW THEY WORK IN PRACTICE.

A. Section 3 of the NC Procedures provides the structure for studying certified Generating Facilities greater than 20 kW up to 2 MW in size, known as the "Fast Track" process, which can encompass anything from small commercial rooftop solar to smaller ground-mounted utility-scale solar. Facilities of this size may be expected to have potential impacts either individually, or in aggregate with other Generating Facilities in a concentrated area. The NC Procedures facilitate expedited study of Fast Track eligible Interconnection Requests through evaluation of technical screens (known as the "Fast Track screens") to determine whether or not impacts of the proposed facility require further review. "Failure" of technical screens is not a negative moniker; rather this is a "flag" to assure that potential impacts to the system caused by the proposed facility are either (1) further checked and confirmed to be *de minimis*, or (2) resolved through some kind of engineering solution, such as a facility Upgrade to the utility's system. When possible this additional review is completed within the "Supplemental Review" process briefly discussed above, which again simply provides time for the utility to directly evaluate potential system impacts, beyond just indicative screening criteria. For example, under

Supplemental Review, the most important additional evaluation includes circuit modeling under a minimum load scenario to check for the possibility of overvoltage impacts. When additional review time appears necessary to expand review to something closer to a full "study," and the extent of such additional review is difficult to determine ahead of time, the project proceeds to the full Section 4 Study Process.

Q. PLEASE DISCUSS THE COMPANIES' PROPOSED MODIFICATIONS TO THIS SECTION 3 PROCESS, AS DETAILED IN THE NC PROCEDURES REDLINE.

A. The Companies ultimately proposed very few changes to the Fast Track and Supplemental Review Processes. The most significant change proposed by the Companies is to offer Fast Track Interconnection Customers 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.

Q. PLEASE DESCRIBE THE SPECIFIC NC PROCEDURES SECTIONS AND MODIFICATIONS PROPOSED BY THE COMPANIES RELATING TO FAST TRACK.

A. The Companies propose the following substantive changes to the NC Procedures Fast Track process:

Section 3.1: The Companies are proposing to allow a utility and Interconnection Customer to mutually agree that an Interconnection

Request can be studied pursuant to the Section 3 process even if the Interconnection Customer otherwise would not be eligible for Fast Track.

Section 3.1.1: In order to provide greater efficiency in the Fast Track and Supplemental Review process, the Companies propose the addition of a Section 3.1.1, to allow the Interconnection Customer the option to elect to proceed directly to Supplemental Review. This new Section 3.1.3 benefits Interconnection Customers by allowing them the option to proceed directly to Supplemental Review and avoid the natural delays involved when having to transition from Fast Track to Supplemental Review.

Section 3.2.1.4: The Companies propose the deletion of a provision related to synchronous and induction generators, since the Fast Track section is generally restricted to inverter-based generation only.

Section 3.3: The Companies in this updated section clarify that when the Fast Track process is insufficient and further evaluation is necessary, the Companies will provide data and analyses underlying this conclusion *upon request* by the Interconnection Customer. Based on the Companies' experience, the majority of Interconnection Customers have not previously requested this information. Additionally, requiring this information to be given to each Interconnection Customer, even when unneeded, can lead to increased costs and the consumption of engineering resources that could otherwise be spent processing additional Interconnection Requests. Thus, the Companies propose to provide the information outlined in Section 3.3 upon request by an Interconnection Customer.

Section 3.3.2: The Companies clarify that an Interconnection Customer must accept the offer of Supplemental Review *in writing*. This update is simply to assure clear documentation and communication between the utility and the customer.

Section 3.4.1.2: The Companies propose to add language to this section preventing the utility from preparing an unnecessary Interconnection Agreement, in the event an Interconnection Customer is not agreeable to making changes to their facility design to accommodate an interconnection.

Additionally, the Companies propose the below changes that are more clerical nature as follows:

Section 3.1: The Companies propose deletion of a redundant phrase referencing "inverters."

Section 3.2.2.4: The Companies propose to add language to this section to make it consistent with Section 3.2.2.2.

Section 3.4: The Companies propose to change the timeline outlined in this section from 15 to 10 Business Days, to correct an inconsistency between Sections 3.3.2 and 3.4.

Q. WHY HAVE THE COMPANIES PROPOSED TO ALLOW INTERCONNECTION CUSTOMERS TO PRE-DESIGNATE THEIR INTENT TO PROCEED DIRECTLY TO SUPPLEMENTAL REVIEW?

A. Currently under Fast Track, screen failure requires a pause in the process to allow for a back-and-forth communication between the utility and

Interconnection Customer. This particular communication is required to (1) inform the Interconnection Customer of the screen failure; (2) request authorization to proceed the facility to additional study through Supplemental Review; and (3) request an additional deposit to continue the evaluation under the Supplemental Review process. Under the Companies' proposal, if an Interconnection Customer (after consultation with the Companies or based on their own experience) believes they may fail the Fast Track technical screens, they can simply go straight to Supplemental Review without spending time under the Fast Track study process. This modification would allow projects to be processed more quickly and to more efficiently proceed to Supplemental Review if and when they fail one or more Fast Track screens.

Q. DURING THE RECENT AE-LED STAKEHOLDER PROCESS, DID OTHER PARTIES RECOMMEND MORE SIGNIFICANT CHANGES TO THE FAST TRACK AND SUPPLEMENTAL REVIEW PROCESS?

A. Yes. IREC proposed significant changes to the Section 3 Fast Track and Supplemental Review process, including: (1) expanding Fast Track eligibility under NC Procedures Section 3.1; (2) modifying the 15% peak load Fast Track screen in Section 3.2.1.2; and, (3) recommending an overall redrafting of Supplemental Review Section 3.4, to replace the current process with a number of additional supplemental screens.

Q. PLEASE EXPLAIN WHY THE COMPANIES DO NOT SUPPORT SIGNIFICANTLY CHANGING FAST TRACK ELIGIBILITY.

A. During the AE-led stakeholder process, IREC proposed to increase the Fast Track eligibility limit for ~ 25 kV and 34.5 kV class circuits (≥ 15 kV and < 35 kV) from 2 MW to 3 MW, for locations within 2.5 miles of the substation. This change provides no benefit to Interconnection Customers, and the Companies therefore do not support the proposal. Specifically, no benefit is provided by this change because multi-MW facilities, whether 1 MW or above, generally require a system protection study be performed in order to assure proper series overcurrent element coordination between all distribution protection devices. However, as noted above, the Companies support a minor change to Section 3.1 to allow an Interconnection Customer and the utility to mutually agree to evaluate an Interconnection Request through the Section 3 process even if the Interconnection Customer otherwise would not qualify for Fast Track. The Companies believe this flexibility is reasonable and allows DEC and DEP to assess potential unique situations where larger or unique Generating Facility interconnections may be appropriately studied through Fast Track.

Q. DID IREC PROPOSE ANY ADDITIONAL CHANGES TO THE FAST TRACK ELIGIBILITY LIMITS?

A. Yes. IREC also proposed increasing the Fast Track eligibility limit for 5 kV class circuits in any location on a circuit from 100 kW to 500 kW. For DEC, DEP, and even Dominion, 5 kV class circuits (also known as 4160 volt circuits) are of a legacy design and configuration, often dating back to the early to mid-20th century. This existing distribution infrastructure design is still appropriate to reliably serve small areas of dense customer load, but due to it being older, with the potential for designs and type of components which work fine but are no longer used elsewhere, the Companies assert that the potential risk for system impacts occurring to the system from larger generator interconnections above 100 kW is significant. Furthermore, these circuits are in the extreme minority in North Carolina – only about 6% of Duke Energy's distribution circuits in North Carolina are 5 kV class (~195 out of a total of ~3,170 distribution circuits in North Carolina, mostly located in urban districts). Therefore, due to the small number of circuits involved, and increased possibility of reliability and operational risks resulting from the proposal, the Companies believe that increasing Section 3.1 Fast Track eligibility to include Interconnection Requests between the existing 100 kW limit and IREC's proposed 500 kW is inappropriate. Additionally, the Companies note that IREC's increased Fast Track eligibility proposals seemingly mirror the equivalent table in the FERC-approved Small Generator Interconnection Procedures ("SGIP"). However, the Companies assert that adherence to the SGIP is not "one size fits all" and, in this case, is not in North Carolina's best interests; rather, a serious and functional consideration of North Carolina's infrastructure and unique circumstances should be considered in establishing the NC Procedures.

Q. PLEASE EXPLAIN WHY THE COMPANIES DO NOT SUPPORT IREC'S PROPOSALS TO MODIFY THE FAST TRACK SCREENS.

A. During the 2017 Stakeholder Process, IREC proposed a change to the 15% peak load screen in Section 3.2.1.2. The Companies do not support IREC's proposed changes to the 15% load screen because modifying application of this screen as IREC suggests removes an extremely important "flagging step" in the interconnection process. This "flagging step" is important as DER penetration grows behind individual service transformers. This is because in North Carolina, customer-sited residential and commercial rooftop solar is primarily "net-metered" in nature versus being designed solely for "power export." As this customer-sited roof top solar continues to grow, the risk of uncontrolled high voltage [defined as voltage in excess of 105% of nominal value, as specified in NCUC Rule 8-17 (b) (1)] for other retail load customers served off a common transformer will grow. Thus, the 15% screen is a valuable "flagging step" in identifying the potential for uncontrolled high voltage occurrences. Therefore, the 15% screen is necessary to mitigate this problem before it occurs, rather than waiting for negative consequences to result.

Q. DOES THE FACT THAT MANY FAST TRACK-ELIGIBLE PROJECTS ARE NOT PASSING THE FAST TRACK SCREENS SIGNIFY THAT THE FAST TRACK PROCESS IS NOT WORKING EFFECTIVELY?

A. No, the fact that many Fast Track-eligible projects are not passing Fast Track screens does not signify that the Fast Track process is not working effectively. During the 2017 Stakeholder Process, the Companies shared how the majority of Interconnection Requests proposing to interconnect to the Duke Utilities under Fast Track initially fail the Fast Track screens, but are then successfully evaluated for interconnection through Supplemental Review. IREC suggested these screen failures are evidence that the Companies are not applying the Fast Track screens appropriately. However, similar logic would lead one to conclude that since the vast majority of college students fail to attain a grade point average in excess of 3.75, university professors must be designing their tests to be too difficult.

Q. WOULD AN INTERCONNECTION CUSTOMER THAT FAILS A FAST TRACK SCREEN BE PROHIBITED FROM INTERCONNECTING AS A RESULT?

A. No. Just as many college students that obtain a grade point average below 3.75 still successfully navigate college and graduate, Interconnection Customers that fail one or more section 3.2 Fast Track "Initial Review" screens can similarly still proceed efficiently through Supplemental Review or, if needed, the Section 4 full study process to support the interconnection. Although the Companies do not dispute that a significant number of projects "fail" the Section 3.2.1.2 screen, a screen failure is not a "bad grade," rather, these screens are designed to be "flagging mechanisms" and simply represent a step in the project's continued movement through the interconnection process. Failure of a screen simply indicates to the utility's engineers that closer scrutiny of the proposed generator interconnection is needed to ensure the interconnection can be accomplished safely and reliably, in accordance with the NC Procedures. A screen failure gives the utility the opportunity to identify through Supplemental Review local pockets of high solar penetration as they begin to occur, which is valuable information for the utility as it continues to assess the increasing impacts of distributed generation.

In conclusion, the Fast Track screens should be viewed as an alert mechanism for identifying any potential impacts from proposed interconnections, which if undetected, can potentially create an unsafe customer-sited generator interconnection and, potentially, future costs to both the utility and its customers.

Q. PLEASE SUMMARIZE THE COMPANIES' POSITION ON IREC'S PROPOSED REVISIONS RELATING TO THE FAST TRACK SCREENS.

A. For the reasons discussed above, the Companies do not support modifications to the 15% of peak load screen and the other Fast Track screens. The Companies also do not support changes to the current approach to sectionalizing a "line section" in applying the 15% screen, as the current approach is reasonable and continues to represent Good Utility Practice at this time to ensure safe and reliable interconnection of new Generating Facilities under the Fast Track process. The Companies also commit to continue to monitor evolving utility industry standards related to interconnecting small generators, in addition to monitoring actual performance on their systems and at customers' facilities, in order to better determine whether evolving the Fast Track screens under the NC Procedures may be warranted at any point in the future.

Q. LOOKING AHEAD, ARE THE COMPANIES CONTINUING TO EVALUATE WAYS TO IMPROVE THE EFFICIENCY OF THE FAST TRACK AND SUPPLEMENTAL REVIEW PROCESS?

A. Yes. The Companies recognize the importance of providing Interconnection Customers an efficient Fast Track and Supplemental Review process that is protective of system safety and reliability, while additionally ensuring that power quality is maintained for all customers. The Companies are more than willing to discuss further ways to improve the Fast Track process, and recommend doing so through the newly formed and operating TSRG.

Q. TURNING TO SUPPLEMENTAL REVIEW, WHAT MODIFICATIONS HAVE THE COMPANIES PROPOSED TO THIS SECTION?

A. The Companies propose only two minor changes to the Supplemental Review process:

Section 3.4: The Companies propose to change the timeline in Section 3.4 from 15 to 10 Business Days, to correct an inconsistency between Sections 3.3.2 and 3.4.

Section 3.4.1.2: The Companies propose to add language that prevents the Utility from unnecessarily preparing an Interconnection Agreement, in the event an Interconnection Customer is not agreeable to making changes to their facility design to accommodate an interconnection where the Companies determine that potentially costly interconnection facilities or Upgrades are required.

Q. PLEASE EXPLAIN WHY THE COMPANIES BELIEVE THAT NORTH CAROLINA'S SUPPLEMENTAL REVIEW PROCESS NEEDS ONLY LIMITED MODIFICATIONS AT THIS TIME.

A. The current Supplemental Review process provides valuable flexibility for both the Utility and the Interconnection Customer. Additionally, the Companies have utilized the Supplemental Review process with much success; when a project fails to pass one or more Fast Track screens, the project most often proceeds to Supplemental Review where it is then successfully evaluated. In some cases, Fast Track-eligible projects require additional technical evaluation but do not need to undergo the Section 4 study process to ensure they can be safely and reliably interconnected. This happens, for example, when the Companies evaluate a moderately-sized commercial PV system greater than 20 kW in size, like a 50 kW sized project. Although this project may not pass the 15% load screen, either at the transformer zone or line section zone, and the screen failure may be solely from its own capacity or caused in part by local aggregate PV close by, the facility's location on or very near a circuit backbone with no complicating factors (like voltage regulators) may keep its impact minimal and not require the engineering labor involved in extensive circuit modeling. In these cases the Supplemental Review process offers flexibility for some small amount of "study" (e.g., further investigation in circuit topology) that cannot occur through simple screen evaluations. However, larger projects or locations with more complexity may be referred to the Section 4 study process to assure that circuit impacts of interconnecting the proposed Generating Facility are well-understood before proceeding to an Interconnection Agreement.

Q. PLEASE EXPLAIN WHY THE COMPANIES SPECIFICALLY REJECT THE ADDITION OF SCREENS TO THE SUPPLEMENTAL REVIEW PROCESS.

A. The addition of standardized screens to the Supplemental Review process implies that there is a complete and uniform understanding of every possible future design of DER and how it might connect to the distribution system, and, moreover, that distribution systems in North Carolina are 100% equivalent to distribution systems elsewhere. Neither premise is correct. Rather than adopting new screens within the Supplemental Review process, the Companies would support a process of continual evaluation of the Fast Track process screens, taking into account the specifics of the distribution systems involved, along with industry developments. The Companies' recently formed TSRG will provide a forum to evaluate whether a more well-defined Supplemental Review process would create benefits over the current flexible Supplemental Review process that exists today.

Q. PLEASE EXPLAIN DUKE ENERGY'S SPECIFIC CONCERNS WITH ADOPTING IREC'S PROPOSED 100% MINIMUM LOAD SCREEN AS AN "EFFECTIVE" SUPPLEMENTAL REVIEW.

A. The Companies do not support "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.

The 90% minimum load screen is designed to make the important determination of whether a proposed Generating Facility may cause "backfeed" or reverse flow to occur at the critical circuit and substation zones. Backfeed occurs where, at any one instant in time, the load in a particular distribution system zone is exceeded by interconnected generation operating in that same zone. While this issue has not been well-addressed in utility industry standards, it is a critical item and should not be assumed to be permitted when passing all Fast Track screens. This is because a known potential for backfeed raises additional technical issues that must be addressed. For example, voltage regulator controls for substation bus regulators and/or circuit exit voltage regulators must be of a specific type and programmed a specific way in order to allow backfeed. Once it is known that backfeed may occur, this issue must be addressed or the utility risks creating improper voltage levels for retail load customers. The use of 90% instead of 100% allows for some margin to account for the normal and very real shifting of load patterns that occur across circuits and across substations. In addition, the 90% screen is a more practical analysis due to the metering equipment and associated data often available at critical circuit and substation zones that can be used for the analysis.

Q. ARE THERE ADDITIONAL REASONS IREC'S 100% MINIMUM LOAD SUPPLEMENTAL REVIEW SCREEN SHOULD BE REJECTED?

A. Yes. The Companies understand IREC's proposed 100% minimum load Supplemental Review screen to apply to all line sections, similar to the 15% peak load screen contained at Section 3.2.1.2. This approach is inappropriate for several reasons. First, downstream zones will not always be equipped with metering under DEP's and DEC's standard distribution system design. 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. Further, 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. While the Companies do not support IREC's proposal with regard to the 15% Fast Track screen, the Companies do commit to continue to monitor industry standards, practices, and trends, as well as engage in further dialogue about these issues through the now-operating TSRG.

Q. PLEASE EXPLAIN WHY DUKE ENERGY REJECTED IREC'S PROPOSED VOLTAGE AND POWER QUALITY AND SAFETY AND RELIABILITY SCREENS.

A. As the Companies asserted in an earlier answer, simply desiring to match provisions in the FERC-approved SGIP is not sufficient justification for change.

The Companies already consider and utilize the bulk of the items specified in the voltage and power quality and safety and reliability screens recommended by IREC, in different ways across the Fast Track, Supplemental Review, and System Impact Study process, although not in exactly the same way. For example, in the Supplemental Review process, the minimum amount of modeling necessary is already performed to assure that service to retail customers would not be adversely impacted due to the proposed interconnection and will remain with proper service voltages per the Commission's regulations, specifically NCUC Rule 8-17(b)(1). The Companies' focus is on continuous improvement of interconnection evaluations, performed accurately and expediently, to assure compliance with NCUC rules and maintenance of reliability and power quality. These additional proposed screens instead, act to over-prescribe to the utility how to get to the end result.

Additionally, IREC's proposed screens are not necessary to effectively process Interconnection Requests, but, to the contrary, reduce flexibility and impose additional administrative burdens upon utilities administering the process, diverting resources that are better spent performing full studies and processing the queue. To administer the IREC-supported screens, the study engineer would have to specifically address and document each of these criteria, when in some cases some of these screens are not necessary to spend time on, and in other cases the subjectivity of some of the screens have high potential to cause more confusion for the study engineer and Interconnection Customer alike, with no associated value for the Interconnection Customer, the utility, or the utility's nearby retail customers. Rather, the Companies assert that they can and have effectively managed many Fast Track and Supplemental Review interconnection process and do not support these changes at this time.

The purpose of Supplemental Review is to avoid full System Impact Study and increase efficiency in processing the queue where practical. In my view, implementing these unnecessary screens would only further clog the queue. Finally, the Commission has already declined to adopt this more defined Supplemental Review Process advocated by IREC in 2015, based on the reasoning that to do so would not support the goal of clearing the queue.

Q. IN CONCLUSION, AND BASED UPON YOUR KNOWLEDGE OF DUKE ENERGY'S IMPLEMENTATION OF THE FAST TRACK PROCESS IN NORTH CAROLINA, IS THE CURRENTLY-APPROVED SECTION 3 FAST TRACK AND SUPPLEMENTAL REVIEW PROCESS BEING SUCCESSFULLY AND

EFFECTIVELY IMPLEMENTED FOR THE BENEFIT OF THE COMPANIES' CUSTOMERS?

A. Yes. The Companies believe that Interconnection Customers are most interested in safely and efficiently completing the installation of their DER project, and the Companies are interested in the same, with the additional interest of maintaining and continually enhancing a safe, reliable, and economic power system. The Companies have never had any interest, nor do they today, in not attempting to continually minimize the time it takes for DER facilities to interconnect to the system.

Premature changes to the Fast Track and Supplemental Review process would make sweeping assumptions about North Carolina's distribution systems and will increase the complexities of managing the interconnection process, which has the potential to slow down, rather than speed up, interconnection requests progressing in this process.

The Companies support maintaining flexibility in the current Fast Track and Supplemental Review process so as to allow the Companies to build on their increasing success with moving these projects through the Section 3 interconnection process, and maintaining an open technical dialogue within the TSRG to assure that North Carolina's approach to processing smaller DER interconnections meets our customers' needs while ensuring that North Carolina is not out of touch with developing technical standards and industry trends.

SECTION IV: MATERIAL MODIFICATION & NEW TECHNOLOGIES

Q. PLEASE EXPLAIN THE MEANING OF THE TERM "MATERIAL MODIFICATION" UNDER THE NC PROCEDURES.

A. Material Modification is defined in Section 1.5 of the existing NC Procedures as "a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades." Additional guidance as to the "indicia" of what constitutes a material modification are also provided in Section 1.5.1 of the NC Procedures.

Q. WERE REVISIONS TO THE DEFINITION OF "MATERIAL MODIFICATIONS" DISCUSSED DURING THE 2017 STAKEHOLDER PROCESS?

A. Yes. During Working Group 2 of the stakeholder process, developer stakeholders expressed an interest in reviewing the Material Modification definition to address concerns over equipment changes during the Interconnection Request process as well as the use of energy storage technology.

At least some consensus was reached on proposed changes to Section 1.5 of the NC Procedures. The Companies and Working Group 2 agreed on a restructuring of Section 1.5 to detail what may constitute a change as "material." The revisions now specify changes that are expressly disallowed before a System Impact Study begins, versus including a greater scope of changes that are disallowed after a System Impact Study begins.

Q. PLEASE EXPLAIN WHY THE COMPANIES' REVISIONS TO THE MATERIAL MODIFICATION STANDARD SHOULD BE ADOPTED.

A. The bulk of the Companies' proposed revisions to the material modification provisions reflect significant stakeholder consensus. The Companies note, however, that the importance of certain details, which may not have been consensus points, cannot be overstated and are key to effective implementation. This includes utilization of the System Impact Study agreement execution date as a decision point for certain modification considerations, and the importance of only allowing changes to the DC portion of a facility if all elements of the production profile are considered.

Specifically, the Companies propose in the NC Procedures Redline in sections 1.5.1(a) and 1.51(b) to use the date of the "execution of the System Impact Study agreement" as the determining point of fact on when a study has or has not started. The date of agreement is a documented step in the process and allows Utility and Interconnection Customer alike to be clear on whether 1.5.1(a) and 1.5.1(b) are applicable.

While changes to the DC portion of a facility indeed do not impact several components of a System Impact Study, failure to account for the production profile of a facility could produce grossly incorrect study results. The production profile of a Generating Facility has become a more crucial component going forward as independent generators seek more flexibility on how the operate their facilities. For example, failing to account for generation export at 6 AM or at 8 PM, which might occur where battery storage has been added to a solar facility, would produce incorrect study results since interconnection studies for solar facilities typically do not account for operation at those times. Interconnection studies also typically do not account for large loads (such as battery charging).

Q. PLEASE DESCRIBE THE COMPANIES' PROPOSED LANGUAGE AROUND THE DEFINITION OF THE CAPACITY OF A GENERATING FACILITY TO ACCOMMODATE NEW TECHNOLOGIES.

A. Similar to the Material Modification provisions of the NC Procedures, the Companies and other stakeholders were able to reach at least partial consensus regarding modifications to the definition of Capacity of a Generating Facility throughout the Stakeholder Process.

Specifically, the Companies support modifying the proposed "capacity" of a Generating Facility for purposes of study from the current standard of Maximum Physical Export Capability Requested. The Companies agreed that for power flow (thermal and steady-state voltage) studies, the capacity of the facility to be studied does not necessarily have to be the maximum physical export capability of the equipment (i.e., the "full nameplate") and may be limited by the Interconnection Customer to a requested (lower) level of export service, where the export capability is physically limited through technical means such as control systems or settings. For short circuit studies, the capacity of the facility is more generally connected to the full nameplate rating of the facility, regardless of control systems, settings, and other programmable or configurable equipment. Therefore, the Companies agreed with proposals made through Working Group 2 to modify the definition of the Capacity of a Generating Facility, as long as the System Impact Study Agreement provisions 6.1 and 6.2 were accepted to specify that short circuit analysis under section 6.1 considers the Nameplate Capacity of the Generating Facility, while the thermal/voltage analysis considers the new definition of Maximum Capacity of a Generating Facility.

Q. WHAT ISSUES WERE RAISED RELATED TO ENERGY STORAGE TECHNOLOGY THROUGH THE WORKING GROUP 2 PROCESS?

A. The 2015 revisions to the NC Procedures already recognized that a "Generating Facility" requesting interconnection to the Companies' systems could include both a device "for the production ... of electricity" "and/or storage for later injection of electricity." Because the NC Procedures already recognize energy storage devices as eligible for interconnection study and an Interconnection Agreement, the bulk of the Working Group 2 discussion focused on when and how energy storage devices may be added to an existing Interconnection Request without triggering the material modification standard.

Q. WHAT WAS THE RESULT OF THE WORKING GROUP 2 IN RELATION TO ENERGY STORAGE TECHNOLOGIES AND REVISIONS TO THE NC PROCEDURES?

A. Through discussions in the Working Group 2 meetings, the Companies agreed to allowing the addition of equipment on the direct current ("DC") portion of a facility, such as energy storage, without this necessarily being considered a Material Modification; however, this proposed exemption from the Material Modification standard can only be functionally accommodated if key elements of the original Generating Facility remain unchanged, such as a facility's daily production profile.

The Companies are supportive of accommodating new technologies such as storage. However, for any Interconnection Requests that have already begun System Impact Study, the utility must have assurance that the Companies' study assumptions related to the production profile of the Generating Facility are not invalidated through modifications to the generating facility. Importantly, the Companies' acceptance of battery storage additions to pre-existing IRs is conditioned upon proposed modifications to the Interconnection Request form that require an Interconnection Customer to provide a detailed generation production profile along with other related information to account for the newer technologies as part of the study process. If an Interconnection Customer elects to add battery storage to an already-submitted Interconnection Request, any change to the production profile—shifting the output of the

Generating Facility earlier or later—would still constitute a Material Modification for any Interconnection Request that has begun System Impact Study.

The Companies' proposed changes within the Interconnection Request Form and the Material Modifications section 1.5 are designed to better accommodate energy storage technologies, while ensuring future safe and reliable interconnected operation of such facilities with the Companies' systems.

SECTION V: INSPECTION OF INTERCONNECTED GENERATING FACILITIES

Q. PLEASE DESCRIBE THE CHANGES THAT THE COMPANIES ARE PROPOSING TO SECTION 6.5 OF THE NC PROCEDURES.

A. The Companies are proposing to modify Section 6.5 of the NC Procedures to enable a more robust ongoing inspection procedure to ensure continued safe and reliable operations of Generating Facilities interconnected with DEP and DEC. While Section 6.5 of the current NC Procedures already permits the Companies to inspect an interconnected Generating Facility as a general matter, the new provisions expressly identify the right of the Companies to inspect the medium voltage AC side of each interconnected Generating Facility under certain identified circumstances, as discussed further below.

Q. WITH RESPECT TO SECTION 6.5.2, WHY HAVE THE COMPANIES NOT PREVIOUSLY INSPECTED CERTAIN GENERATING FACILITIES?

A. Beginning in 2016, the Companies began working with Advanced Energy to establish a comprehensive inspection and commissioning program for all new utility-scale solar Interconnection Customers prior to the utility authorizing energization and officially certifying the Interconnection Customer's "permission to operate" the Generating Facility. The Companies established this more robust inspection and commissioning process as a result of experienced power quality events that originated on particular Interconnection Customers' medium voltage facilities located on the Interconnection Customer's side of the point of interconnection with the Companies' systems.

Prior to 2016, the Companies' inspection process did not include a robust inspection of the medium voltage AC side of an interconnected Generating Facility. As the Companies have gained more experience through interconnection of hundreds of utility-scale solar projects, it has become apparent that a rigorous inspection process is needed to ensure that each Generating Facility's Interconnection Facilities have been constructed consistent with the Companies' generally-applicable construction and design standards. This process is designed to better ensure that Interconnection Customers' Interconnection Facilities will operate in a safe and reliable manner in compliance with terms of the Interconnection Agreement.

Q. UNDER WHAT CIRCUMSTANCES WOULD INSPECTION BE REQUIRED AFTER COMMENCEMENT OF PARALLEL OPERATION?

A. As described in more detail in the newly proposed Section 6.5.3, it is reasonable for the Companies to periodically inspect the medium voltage AC side of each Generating Facility on a schedule that is similar to the inspection cycles that are applied to the Companies' own distribution facilities. In addition, and as is described in more detail in the newly proposed Section 6.5.4, it is reasonable for the Companies to be able to inspect the medium voltage AC side of each Generating Facility where certain adverse system safety and/or reliability events occur. Specifically, this section expressly provides DEC or DEP the right inspect the Interconnection Customer's medium voltage facilities should the Companies discover that the interconnected Generating Facility has the potential to cause disruption or deterioration of service to retail electric customers, to cause damage to the Utility's System or Affected Systems, or is otherwise is imminently likely to endanger life or property or cause a material adverse effect on the security of, or damage to the grid.

Q. WHY IS IT NECESSARY TO INCLUDE THESE PROVISIONS?

A. As stated above, these inspections are likely already permitted under the NC Procedures. However, the changes are being proposed both to expressly establish a process for potential ongoing inspection of Generating Facilities operating in parallel with the Companies' grids as well as to ensure cost recovery of the inspection costs. Currently, there is no express mechanism under the NC Procedures by which the Companies can recover the costs of inspections required after commencement of parallel operation. The inspection costs will consist primarily of Advanced Energy's costs to perform such inspections.

SECTION VI: GOOD UTILITY PRACTICE

Q. CAN YOU PLEASE DISCUSS THE CONCEPT OF "GOOD UTILITY PRACTICE" UNDER THE NC PROCEDURES?

A. Good Utility Practice is defined in the NC Procedures as

> "Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region."

Good Utility Practice is a very important concept under the NC Procedures, as the Companies are completely and solely responsible for the safety, reliability, and power quality of the power system which they have built and maintained over decades to cost-effectively serve customers' electricity needs in North Carolina. In carrying out this responsibility, related to interconnections or otherwise, the Companies must continually evaluate what constitutes Good Utility Practice. The Companies do this in a number of ways, including (in no particular order) through: involvement in standards bodies like IEEE (Institute of Electrical and Electronics Engineers) and NESC (National Electrical Safety Code), formal and informal sharing of technical information with other utilities, and careful application of power system theory and responsible engineering practices developed over time through its own engineering expertise.

Due to the Companies' accountability and responsibility for safety, reliability, and power quality across the power system, the Companies continuously and seriously consider what technical standards to put into place, and why, how, and when to change these standards. The Companies are fully committed to the long-term safety and reliability of the power system and are proud of the role they play in being careful stewards of the power system on behalf of the customers we serve.

Q. PLEASE EXPLAIN HOW THE COMPANIES HAVE APPLIED "GOOD UTILITY PRACTICE" UNDER THE NC PROCEDURES SINCE 2015.

A. The Companies have always applied the concept of Good Utility Practice in serving both retail customers and Interconnection Customers, even before the term was implemented under the NC Procedures in the context of interconnections. With the recent, significant uncontrolled growth of new generator interconnections and especially utility-scale solar on the distribution system, the Companies began the process of considering what provisions of then-applied Good Utility Practice might need to be altered, since multi-MW DER interconnections were clearly starting to move from a rare and unique occurrence to the current "living laboratory" of unparalleled utility-scale generator interconnections that the Companies are managing today.

Beginning in 2016, DEP and DEC applied significant distribution engineering resources to evaluate whether Good Utility Practice required additional study criteria to be applied during System Impact Study to evaluate the impact of utility-scale solar generators on electric system safety, reliability, and power quality As described in the Companies' September 2016, filing with the Commission[1], DEC and DEP have increasingly began to experience power quality impacts and to recognize potential operational reliability risks associated with the growing levels of utility-scale solar generators interconnecting to the distribution system in North Carolina. Specific to applying Good Utility Practice, I and other engineers within the Companies were increasingly recognizing that historically valid "steady state" engineering studies were inadequate to properly predict power quality issues associated with utility-scale solar projects connected to the distribution system and, as such, more robust and

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[1] *In the Matter of Generator Interconnection Standard, Tariffs and Contract Forms*, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to September 8, 2016 Order Requiring Response and Requesting Comments, Docket No. E-100, Sub 101 (filed Sept. 22, 2016).

dynamic models and standards were needed to properly study this growing level of DER. Since that time, the Companies have established a number of reasonable and technically justified policies and standards applicable to studying all utility-scale Interconnection Requests, including both solar and non-solar, and third-party and Duke Energy-owned Generating Facilities.

It is worth stating that any change to Good Utility Practice is not taken lightly; rather, changes are weighed (like any engineering decision) in terms of the benefits and advantages of changing Company practices, versus the costs, impacts, and disadvantages that may also be incurred due to the change by retail customers, interconnection customers, or the Company. It is also worth mentioning that the vast majority of engineers within Duke Energy at the Senior Engineer, Lead Engineer, or Principal Engineer levels that are involved in these decisions are licensed professional engineers with deep understanding of DEC's and DEP's systems.

Q. PLEASE PROVIDE AN EXAMPLE OF THE COMPANIES' EVOLVING GOOD UTILITY PRACTICE.

A. Most recently, the DER Method of Service Guidelines, which took effect October 1, 2017, illustrates the Companies' adaptation of Good Utility Practice to the evolving interconnection landscape in North Carolina. The Method of Service Guidelines provide guidance on methods of interconnection for distributed energy resources, which allow for sustainable methods of interconnection for all sizes of DER while maintaining the Companies' ability to provide reliable retail electric service for current and future retail customers.

The Method of Service Guidelines provide guidance in several areas: (1) selection of the appropriate method of interconnection and point of interconnection on the utility system (transmission, substation, distribution) based upon individual generator project size; (2) configuration options for line design and construction on the distribution system to allow for changes in future load patterns alongside interconnections; (3) appropriate voltage regulation zones for interconnection on the distribution circuit backbone[2]; (4) sustainable and non-discriminatory practices for construction of line extensions for DER; (5) appropriate methods for screening and assessing the potential for power quality impacts to nearby retail customers[3].

Importantly, Interconnection Customers proposing new projects that are now impacted by the Method of Service Guidelines are presented an alternative point of interconnection or method of service during System Impact Study, such as a direct-to-substation connection or a transmission-level interconnection, that more appropriately reflects the ability of the System to accommodate the Interconnection Customer's Generating Facility.

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[2] Also known as the "LVR" (Line Voltage Regulator) policy
[3] Also known as the "CSR" (Circuit Stiffness Review) policy

Q. PLEASE EXPLAIN WHY THE COMPANIES BELIEVE THAT THEY HAVE APPROPRIATELY APPLIED GOOD UTILITY PRACTICE AND NOT TAKEN UNREASONABLE OR UNJUSTIFIED "UNILATERAL" ACTION IN IMPLEMENTING THE POLICIES YOU JUST DESCRIBED.

A. As an initial matter, due to the Companies' sole and complete accountability and responsibility for the safety, reliability, and power quality of the grid, any action the Companies take to maintain these expectations may always be construed by some to be "unilateral" in nature. Nevertheless, the Companies are sensitive to, and recognize when, continuing certain practices begin to accommodate one type of customer at the expense of another. As generator interconnections moved from an exception and occasional project to an unparalleled quantity, this dynamic became evident. Accommodating utility-scale projects with non-standard methods, on a quantity basis, when a growing number of technical parameters may not yet be well-understood, shifts cost and reliability risk to the Companies' retail load customers and can become unsustainable and incompatible with the Companies' obligation to plan and operate the power system in a safe and reliable manner for all customers.

Based upon the recently-experienced surging growth of utility-scale DER in North Carolina, the Companies began to assess how to ensure electric service to existing retail load customers is not adversely impacted by the surging growth of third party generator interconnections. Early determinations, such as the need to standardize on unity power factor, were among some of the technical "Good Utility Practice" standards that the Companies adopted (after consultation with the Public Staff) going back to the Fall of 2014. Technical complexities began to grow further, and when in early 2016 the Companies experienced a handful of physical events that, although small in number, represented technical factors that had not yet been considered, the Companies began to also communicate to the solar industry as well. Although the TSRG had not yet been established, the Companies held a number of technical presentations with the solar industry to discuss these growing concerns and the need to evolve Good Utility Practice, as follows:

Figure 3: Duke Energy Technical Discussions with Solar Industry

Meeting Date	**Issues Discussed**
June 24, 2016	Addressing construction quality deficiencies on installed solar plants and describing power quality events supporting circuit stiffness evaluation
Sept. 8, 2016	Providing interconnection process update including focus on commissioning and inspections, and describing how CSR will be used as a screen requiring more "advanced study" analysis
Dec. 5, 2016	Addressing line voltage regulator policy, DEP's Distribution System Demand Reduction policy and advanced study development update
April 7, 2017	Addressing line voltage regulator policy applicable to utility-scale DER above 250 kW and discussing inverter functionality
Sept. 15, 2017	Meeting with Public Staff, NCCEBA, and NCSEA to discuss Method of Service Guidelines to become effective October 1, 2017

Sept. 25, 2017	Addressing Method of Service planning guidelines, evolving “flicker criteria,” and providing update on commissioning process

Q. PLEASE EXPLAIN HOW THE COMPANIES’ PROPOSALS SUPPORT THE CONTINUATION OF “GOOD UTILITY PRACTICE.”

A. The Companies’ public service mission in assuring safety, reliability, and power quality requires that it plan, manage, and operate the power system on every time horizon, from electrical cycles out to decades in the future. Recognizing this continuing responsibility to the Commission and citizens we serve in North Carolina, the Companies have developed and adopted sustainable policies and practices that seek to optimize the long-term cost of electric service for all customers, including an assurance of safe and reliable service for decades to come. In creating the Method of Service Guidelines, the Companies proactively took action to explain and codify the Good Utility Practices for DER interconnection in North Carolina. Importantly, the Method of Service Guidelines present sustainable practices that can continue into the future, thereby providing more predictability to Interconnection Customers while also ensuring the Companies can carry out their public service obligations to the Commission and our retail customers in North Carolina.

Q. WILL THE COMPANIES CONTINUE TO EVALUATE AND EVOLVE THEIR GOOD UTILITY PRACTICE?

A. Yes. As explained above, the Companies are committed to continuing to refine Good Utility Practice and to ensure that adequate system safety, power quality and reliability are maintained for all customers. The recent formation of the TSRG further demonstrates the Companies' intentions to promote transparency and increased technical understanding in managing its interconnection queue and the reliability of the power system in North Carolina.

SECTION VII: PROMOTING TRANSPARENCY AND TECHNICAL UNDERSTANDING

Q. PLEASE DESCRIBE THE COMPANIES' ONGOING EFFORTS TO INFORM INTERCONNECTION CUSTOMERS AND OTHER STAKEHOLDERS REGARDING NEW TECHNICAL STANDARDS AND REQUIREMENTS AS GOOD UTILITY PRACTICE EVOLVES OVER TIME.

A. In an effort to improve transparency and reduce the potential for future interconnection-related disputes, the Duke Utilities announced in February 2018 plans to form a North Carolina/South Carolina DER TSRG. Since that announcement, the TSRG has met three times, per its intended quarterly meeting frequency, on April 11, July 19, and October 23/24, 2018. The TSRG is designed to provide a forum for open engineering-focused dialogue and technical discussion among the Companies, the Regulatory Staffs of both the North Carolina and South Carolinas utility commissions, and the renewable energy industry. These discussions have and will continue to focus on new interconnection-related developments or planned revisions to the Companies' existing technical standards in North Carolina and/or South Carolina. The group's structure allows for the Companies and the renewable energy industry to each bring agenda items forward at each meeting.

The TSRG is additionally the intended forum to specifically address new IEEE 1547 standards, discuss issues related to new technologies (such as energy storage and smart inverters), and provide a forum to share the Companies' future consideration of enhanced technical requirements that may be incorporated into the interconnection study process over time. The Duke Utilities have also established a publicly-available webpage[4] that will maintain TSRG-related information and provide advanced notices of regularly scheduled TSRG meetings.

Q. PLEASE EXPLAIN THE COMPANIES' CONCERNS WITH STAKEHOLDER RECOMMENDATIONS THAT "CONSENSUS" OR COMMISSION APPROVAL BE REQUIRED BEFORE THE COMPANIES MAY ADOPT CHANGES TO INTERCONNECTION STANDARDS AND POLICIES.

A. During the Stakeholder Process, the North Carolina Sustainable Energy Association ("NCSEA") recommended that the Commission require either consensus amongst the Companies and stakeholders or prior Commission

[4] https://www.duke-energy.com/business/products/renewables/generate-your-own/tsrg

approval before any changes to the Companies' interconnection policies or technical standards take effect. This is a critically important issue for the Companies and this recommendation should be rejected.

The Duke Utilities' experience is that "consensus" is often very difficult, if not impossible, to achieve. This is because the Companies and solar developers perceive Good Utility Practice differently with regard to the appropriate allocation of engineering and technical risk, as well as the proper assignment of costs to mitigate those risks, between the Interconnection Customer Generating Facility owner and the Utilities and existing and future retail customers. Therefore, the Companies fundamentally disagree with NCSEA's contention that anyone other than the Companies, under the Commission's oversight, should have final decision-making power or "veto rights" over the determination of Good Utility Practice and the implementation of a proposed technical standard.

Q. WHY WOULD THE COMPANIES BE CONCERNED ABOUT REQUIRING COMMISSION APPROVAL PRIOR TO CHANGES TO INTERCONNECTION STANDARDS AND POLICIES BEING PUT IN PLACE?

A. Requiring Commission approval in order to implement new technical standards or requirements would be time consuming and impractical, since the Companies would be forced to either suspend further interconnection studies until Commission approval is obtained or proceed to study additional Interconnection Requests under either an unapproved new technical standard or an old standard that the Companies no longer support as consistent with Good Utility Practice.

Q. PLEASE EXPLAIN HOW THE FORMATION AND OPERATION OF A TSRG CAN HELP BUILD CONSENSUS AND REASONABLY ADDRESS STAKEHOLDER CONCERNS ABOUT TECHNICAL STANDARDS AND GOOD UTILITY PRACTICE.

A. During the stakeholder process, IREC highlighted the Massachusetts Technical Standards Working Group as a model that the Commission should consider in mandating a TSRG in North Carolina. Myself and other members of the Companies' engineering team subsequently invested time to contact National Grid to learn more about the Massachusetts Working Group and to even travel to Massachusetts to attend the November 28, 2017 quarterly Working Group meeting. Since that meeting, and as stated earlier in my testimony, the Companies went about establishing a TSRG, in conjunction with NCSEA, the North Carolina Clean Energy Business Alliance, and the South Carolina Solar Business Alliance, with invitation also extended to the North Carolina Public Staff and the South Carolina Office of Regulatory Staff.

The structure of the TSRG allows for open communication and dialogue but does not assume a requirement of consensus. This aligns with the governing framework of the Massachusetts Technical Standards Working Group. The Massachusetts Working Group bylaws clearly state that "the Utilities have the final decision over which Technical Standards, both common and Utility-specific, to employ for the purposes of interconnecting DG facilities to their respective distribution systems and ultimate control over any Utility-specific and common Technical Standards Manuals they develop."[5] For the avoidance of doubt, the Duke Utilities' TSRG Announcement[6] included similar language:

> *Since Duke Energy is solely accountable and responsible for maintaining adequate customer reliability and power quality, Duke Energy expects that attendees to the meeting understand that the meeting is strictly a discussion forum and not a decision making venue, and Duke Energy maintains the final decision over technical standards employed for the purposes of DER interconnection to its distribution and transmission system.*

As discussed above, the Companies are responsible for and must meet their regulatory obligations to maintain system safety, power quality and reliability for the benefit of their customers. Other stakeholders, including solar developers and their advocacy organizations, have no such obligation. In making decisions regarding the implementation of future technical standards and requirements, the Companies will continue to apply Good Utility Practice based upon their unique knowledge of the grid,

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[5] MA Technical Standards Review Group Bylaws, page 1. Accessible at https://sites.google.com/site/massdgic/home/interconnection/technical-standards-review-group

[6] Available at https://www.duke-energy.com/business/products/renewables/generate-your-own/tsrg

engineering and technical expertise, and collaboration with regional peer utilities and industry forums. Importantly, the Commission will continue to have oversight over any decisions the Companies make with regard to any new technical standards or evolving Good Utility Practice, through its general regulatory power and via the NC Procedures' defined dispute resolution process.

SECTION VIII: DER INTERCONNECTION AND THE FUTURE OF GRID OPERATIONS

Q. BASED UPON YOUR EXPERIENCE ADMINISTERING THE GENERATOR INTERCONNECTION PROCESS SINCE 2015, CAN YOU PLEASE DESCRIBE THE GENERAL CHALLENGES DUKE ENERGY SEES WHEN LOOKING AHEAD TO PLANNING AND OPERATING THE DISTRIBUTION AND TRANSMISSION SYSTEM IN THE UNIQUE DER LANDSCAPE SEEN IN NORTH CAROLINA TODAY?

A. The system of generation, transmission, and distribution of electric power Duke Energy has in place today is planned in an integrated fashion to maximize reliability and minimize cost. This system is continuously monitored and planned over time horizons of years to decades, and is operated in time horizons from electrical cycles to more than a year, in order to continuously assure the reliable and economic delivery of electric power to the Companies' retail and wholesale customers. Changes to the system like geographical load growth and load shifts are handled both in the planning and operating time windows.

The introduction of larger amounts of independent Generating Facilities that are not a part of this integrated planning process do present a serious and growing challenge to the Companies' current paradigms of transmission and distribution system planning and operation. While not necessarily the subject of this proceeding, it is important to highlight for the Commission that interconnecting this unparalleled quantity of utility-scale solar DER may require changes to the way the Companies plan and operate the power system. New investments will undoubtedly be required to meet these growing challenges and to strengthen and modernize the grid in order to better accommodate additional DER both at our customers' homes and businesses as well as on the Companies' distribution system and the bulk electric system. Those issues will likely be addressed in other proceedings before the Commission, and my testimony will simply highlight some of the complexities that I foresee associated with planning and operating the transmission and distribution system with these growing levels of independently-operated DER.

Q. WHAT SPECIFIC CHALLENGES ARE THE COMPANIES ENCOUNTERING RELATING TO TRANSMISSION SYSTEM PLANNING?

A. Today's transmission planning process looks into the future at changes in societal electric power demand and usage patterns (e.g., growth or shifts in various metropolitan areas) and analyzes the state of the system in the coming years. This analysis is done with a simulation that changes the historical load levels at every substation on the system, in order to forecast a future "system state." This analysis then reveals where the next "pinch points" might be in the system (e.g., a transmission line reaching capacity), and develops plans to relieve these future situations well before they occur.

Independent Generating Facilities can be somewhat characterized as a new type of "load," rather than generation, in that they operate independently without adequate correlation to typical load patterns. They also cannot be adequately forecasted in the same ways forecasting is accomplished for load, given that load typically exhibits small annual changes in demand and usage in certain areas. These independent Generating Facilities therefore become a second independent variable for which the transmission planning process must account. Rather than planning for summer and winter peaks, with a comprehensive annual analysis for each, the process must now begin to account for additional planning scenarios and operating contingencies, such as minimum load scenarios, although the exact combinations of load and independent generation may require even more scenarios. This all greatly increases the complexity and cost of the transmission planning process.

Q. WHAT SPECIFIC CHALLENGES ARE THE COMPANIES ENCOUNTERING RELATING TO DISTRIBUTION SYSTEM PLANNING?

A. The distribution planning process is similar to that of transmission planning in terms of planning for changes in load, although the process is performed for individual substations and individual distribution circuits. The challenge of planning for two independent variables equally applies for distribution planning. Further complexity is also introduced by the radial nature of the distribution system; planning practices have been long-rooted with an assumption of the presence of electrical loads and the absence of electrical generation sources. This means that many valid assumptions have been made in the past in modeling and analysis in lieu of having extensive load profile data of local load and generation. Future modeling and analysis will require more granular data from the distribution system (for which telemetry devices may or may not yet exist), will be more complex, and will take longer. Voltage drop can no longer be assumed; now, voltage rise due to increasing levels of DER may be an equal or greater planning and operational challenge.

Another challenge to future distribution planning is how to handle what have traditionally been commonly-applied solutions for shifting patterns between area load in the vicinity of one substation and another. A planning study may reveal that two distribution feeders may need to undergo reconfiguration, since a feeder may have reached capacity. The reconfiguration solution could involve moving a normally open tie point between two feeders, each fed from separate substations, so that the new normally open tie is now closer to one substation and now further from the other. This is commonly known as "load transfer," and is essentially a task of "balancing load" between area substations, making efficient use of existing capital assets as load growth patterns change over time. The physical work involved to complete a load transfer is often as simple as closing a normally open switch, opening a normally closed switch, and updating models; sometimes a small amount of reconductoring may be needed. However, if an existing solar Generating Facility on one of these feeders is "moved" and, as a result, is now further from its substation than it was before (now on the "longer" feeder), the planning study may show that moving the DER pushes voltage too high on its new longer feeder. Therefore, due to the DER, the load transfer cannot take place at all, and the utility must consider alternative and more costly solutions to respond to the load growth. The solution to the shifting load pattern could now be (1) construction of miles of additional feeder, either on existing right-of-way with multiple circuits (with reliability impacts) or (2) more extensive feeder reconfigurations in the area assuming new right-of-way can be acquired, or (3) new substation construction.

Q. ARE ANY OF THE ISSUES YOU MENTION ABOVE ALREADY BEGINNING TO OCCUR, AND, IF SO, WHAT ARE THE FUTURE IMPLICATIONS OF THESE ISSUES?

A. Yes. This problem is already occurring and will increase in frequency and order of magnitude, thereby increasing the cost to serve current and future customers.

Q. WHAT SPECIFIC CHALLENGES ARE THE COMPANIES ENCOUNTERING RELATING TO THE TRANSMISSION SYSTEM AND BALANCING AUTHORITY ("BA") OPERATIONS AS A WHOLE?

A. The challenges with transmission system and BA operations are multi-faceted, and in general will grow proportionally to the amount of independent generating capacity, mostly solar, which interconnects to the system.

Because these generating facilities are not part of the Companies' integrated planning processes and, once installed, they inject unscheduled and unconstrained energy into the system, BA resources must react to provide balancing and ancillary services such as regulation and frequency response. However, there are physical limitations to the BA's capability to reliably operate and absorb such unscheduled and unconstrained energy injections. This limit is known as the Security Constrained Unit Commitment's LROL (Lowest Reliability Operating Level), which is a level below which the BA cannot reduce operational output. This level must be retained through the mid-day valley of the demand curve each day to provide for: (i) frequency regulation; (ii) resource availability to meet the evening peak demand; as well as (iii) resource availability to meet the next morning's peak demand, which is generally higher than the previous evening's peak demand. In combination, this situation results in operationally excessive energy on the BA, caused by operationally excessive installed capacity of independent Generating Facilities, both on the transmission and the distribution system. Looking ahead, these challenges and risks will be amplified, particularly on the DEP BA as the quantity of uncontrolled solar QF installed capacity increases. Effective management of these challenges will translate into costs along with increasing curtailments and needs for other solutions to assure effective system operation within NERC Reliability Standards, like NERC BAL-001-2 (Real Power Balancing Control Performance).

Q. WHAT CHALLENGES ARE THE COMPANIES ENCOUNTERING RELATING TO THE COMPANIES' DISTRIBUTION SYSTEM OPERATIONS?

A. Challenges are on the rise in distribution system operations as well. As an example, the DEP Distribution Control Center and the associated Grid Management organization are focused on outage management, switching operations, and assuring effective availability and operation of the DSDR (Distribution System Demand Response) system. As of October 2018, there are over 290 Generating Facilities greater than 1 MW in operation, totaling over 1300 MW in capacity, on the DEP distribution system. Each of these facilities has an owner and an operator, each of which has a desire or reason to contact the DEP Distribution Control Center from time to time. Coordination and communication with Generating Facility operators now consumes a significant amount of time within distribution system operations. The complexities of feeder switching have grown immensely, as the same issues with load transfers in Distribution Planning, mentioned above, also make distribution field switching by Grid Management much more complex than in the recent past, and this complexity is on the rise. The issue here again is the loss of flexibility in operating the system. Facilities can and are taken temporarily offline on a regular basis to allow switching to successfully occur, but complexity is continuing to escalate. Further effective management of the distribution system will translate into costs that are not easily assignable; the solutions will be significant upgrade work for the DMS (Distribution Management System) along with the possibilities for increasing staffing to manage the growing complexity.

Q. PLEASE SUMMARIZE THE FUTURE IMPLICATIONS THAT, IN YOUR OPINION, WILL RESULT FROM NORTH CAROLINA'S UNIQUE INTERCONNECTION LANDSCAPE WITHOUT TAKING INTO ACCOUNT THE COMPANIES' AFOREMENTIONED CONCERNS.

A. Rapid changes of any type in any given environment (as we have seen with interconnection of utility-scale solar in North Carolina), without accompanying changes to planning paradigms to account for such changes in the planning process, are always accompanied by sharply increased risk profile to the effectiveness, as measured in reliability and cost, of the given system.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(WHEREUPON, Rebuttal Exhibits JWG-1 through JWG-4 are marked for identification as prefiled.)

(WHEREUPON, the prefiled rebuttal testimony of JOHN W. GAJDA is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**REBUTTAL TESTIMONY OF**
Petition for Approval of Generator	)	**JOHN W. GAJDA**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John W. Gajda. My business address is 3401 Hillsborough Street, Raleigh, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed on a Developmental Assignment for Duke Energy Corporation ("Duke Energy"), which is a type of "Special Projects" designation, working in the System Operations group. I am submitting this rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies").

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of the Companies on December 19, 2018.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to address several issues raised in the direct testimony of the Public Staff and certain other intervenors and to provide support for the Companies' proposed revisions to the North Carolina Interconnection Procedures ("NC Procedures"). Specifically, I agree with Public Staff witness Williamson's position on Good Utility Practice, and elaborate on how the Companies' application of Good Utility Practice is in alignment with the Public Staff's expectations of the

Companies' and Dominion Energy North Carolina's ("DENC" and collectively, the "Utilities") responsibility under the NC Procedures. I also respond to the Public Staff's statement that utility flexibility is necessary to most appropriately and efficiently implement Good Utility Practice over time, and rebut the solar advocate intervenors' claims otherwise. Next, I rebut North Carolina Sustainable Energy Association ("NCSEA") witness Paul Brucke and Interstate Renewable Energy Council ("IREC") witness Brian Lydic's proposal to require the Technical Standards Review Group to be changed from a discussion-based forum to a formal proceeding. I then rebut IREC witness Sarah Auck's proposals to significantly overhaul the current Fast Track and Supplemental Review processes by explaining how the current Section 2 and Section 3 processes are working effectively at this time and are tailored to North Carolina's interconnection landscape.

I also respond to NCSEA witness Brucke and NCCEBA witness Christopher Norqual's statements regarding the Companies' perspective and definition of "material modification" as it relates to energy storage, and also explain the Companies' position and acceptance of software controls in determining the maximum output of a generating facility under the NC Procedures Redline. Finally, I explain why the Companies do not support Public Staff witness Williamson's proposal for an independent review of the entire NC Procedures at this time, due to the current ongoing NC Procedures review and the Companies' plans to focus on queue reform and a transition to full grouping studies.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am submitting four exhibits. JWG Rebuttal Exhibit 1 is the Companies' updated redline of the NC Procedures. JWG Rebuttal Exhibit 2 is the Companies' Distributed Energy Resource Method of Service Guidelines (the "MOS Guidelines"). JWG Rebuttal Exhibit 3 provides detail on the Companies' publicly available "Carolinas TSRG Updates" website. Last, I am submitting JWG Rebuttal Exhibit 4, which provides the Commission certain data request responses referenced in my testimony.

I. Good Utility Practice

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S POSITION REGARDING GOOD UTILITY PRACTICE.

A. Public Staff witness Williamson states that it is the Utilities' responsibility to maintain and operate the electric grid in a safe and reliable manner, and emphasizes that Good Utility Practice must include flexibility for changes over time. Expanding on the issue of flexibility, Public Staff witness Williamson details how North Carolina's unique interconnection landscape has "the potential to create operational challenges that must be managed in both the short- and long-term."[1] Based on this unique interconnection landscape, Public Staff witness Williamson contends that short-term "fixes" may be necessary prior to any formal NCIP revisions, and therefore "a

[1] Public Staff Williamson Direct Testimony, at 5.

degree of flexibility should be at the discretion of the Utilities" in applying Good Utility Practice.

In conclusion, Public Staff witness Williamson states that the Utilities are responsible for determining the practices, methods and acts necessary to meet the rules and standards established by the relevant regulatory bodies, and that the Utilities' application of this Good Utility Practice must retain some level of flexibility.

Q. DOES THE PUBLIC STAFF'S POSITION ON GOOD UTILITY PRACTICE ALIGN WITH THE COMPANIES' POSITION?

A. Yes. Based on my reading of Public Staff witness Williamson's testimony, the Public Staff is aligned with Companies' position on Good Utility Practice. Public Staff witness Williamson explains that the Utilities are responsible for determining the practices, methods, and acts necessary to establish Good Utility Practice, consistent with rules and standards established by this Commission and other regulatory agencies such as the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC").[2] However, it is important to distinguish that the relevant regulatory bodies mentioned by the Public Staff as overseeing the Utilities do not directly establish Good Utility Practice; rather, the Companies establish and maintain their engineering guidelines and technical standards in such a way as to assure compliance with the rules

[2] *Id.*

and standards established by the Commission and other relevant regulatory bodies. As I discuss in my direct testimony, since the Companies are completely responsible for ensuring power quality and reliability, the Companies seek to maintain flexibility within the Good Utility Practice construct so as to continually optimize power quality, reliability, and economic considerations for its customers.[3]

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S VIEW THAT THE GOOD UTILITY PRACTICE STANDARD SHOULD BOTH PROMOTE ALIGNMENT WITH PRACTICES OF THE OVERALL UTILITY INDUSTRY WHILE ALSO ALLOWING FLEXIBILITY FOR THE COMPANIES TO APPLY REASONABLE JUDGMENT TO MEET NEW OR EMERGING CHALLENGES?

A. Yes. Public Staff witness Williamson states that the Utilities' application of Good Utility Practice should be consistent with the practices, methods and acts engaged in, or approved by, a significant portion of the electric industry, while also recognizing the need for flexibility to exercise reasonable judgement "to the extent the Utilities identify new or emerging challenges or issues that may impact safety and reliability concerns."[4]

I agree with witness Williamson's statements. The Companies, like most utilities, continuously assess the alignment of their practices and

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[3] DEC/DEP Gajda Direct Testimony, at 24.
[4] Public Staff Williamson Direct Testimony, at 5.

experiences with those of their peers through many venues that facilitate shared practices and utility monitoring. For example, many of the Companies' engineers actively participate in committees within organizations such as the NESC (National Electrical Safety Code), IEEE (Institute of Electrical and Electronics Engineers), Southeastern Electric Exchange, and North American Transmission Forum, to name a few.

However, in order to carry out its mission of delivering safe, reliable, and economic electricity to its customers, the Companies must also be permitted to carry out, with confidence, independent technical design and judgment activities within its own engineering workforce. To this end, the Companies deliberately and consistently hire, for particular key positions, only degreed engineers from ABET (Accreditation Board for Engineering and Technology) accredited institutions. Furthermore, the Companies have an established practice within the Transmission and Distribution departments of requiring Professional Engineering licensure prior to promotion to Senior Engineer, Lead Engineer, or Principal Engineer. Specific to implementing Good Utility Practice within the generator interconnection process, these rigorous standards for advancement promote reasonable judgement and good business practices, grounded in achieving the Companies' overall mission to provide safe, reliable, and economic delivery of electricity.

II. Application and Transparency of Good Utility Practice

Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AS REFLECTED IN THE MOS GUIDELINES?

A. Yes. As background, the MOS Guidelines were developed in order to consider the impacts associated with the Companies' long term planning obligations, so that the Companies could provide reasonable and non-discriminatory access to their distribution systems, while also ensuring this was done in a scalable and sustainable manner. I also discussed the MOS Guidelines in some detail in my direct testimony.[5]

Public Staff witness Williamson states that the Public Staff supports the Companies' application of Good Utility Practice as reflected in the MOS Guidelines. He specifically states that "the MOS [Guidelines] are reasonable guidelines for the Duke Utilities to apply in meeting their obligation to provide safe, reliable electric service to the using and consuming public."[6] For the Commission's reference, I have attached the Companies' MOS Guidelines as JWG Rebuttal Exhibit 2.

Q. DOES THE PUBLIC STAFF CHALLENGE ANY ASPECT OF THE COMPANIES' TECHNICAL STANDARDS AS INCONSISTENT WITH GOOD UTILITY PRACTICE?

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[5] DEC/DEP Gajda Direct Testimony, at 49.
[6] Public Staff Williamson Direct Testimony, at 15.

A. No. The Public Staff did not challenge any aspect of the Companies current interconnection practices as being inconsistent with Good Utility Practice.[7]

Q. DO ANY PARTIES DISAGREE WITH THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AND RESULTING TECHNICAL STANDARDS?

A. While the Public Staff generally supports the Companies' MOS Guidelines and application of Good Utility Practice, witnesses testifying on behalf of NCSEA, NCCEBA, and IREC—the solar industry advocates —generally oppose the Companies' technical standards and requirements. These solar industry advocates specifically contend that the Companies' MOS Guidelines are "overly restrictive" and "not typical" of other utilities around the country.[8]

Q. BASED UPON YOUR EXPERIENCE, WAS IT EXPECTED THAT THESE SOLAR INDUSTRY ADVOCATES MAY DISAGREE WITH THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AND THE COMPANIES' DEVELOPMENT OF THE MOS GUIDELINES?

A. Yes. The Companies understand that the concerns of a developer in any particular instance are generally focused on the specific generating facility

[7] Public Staff Williamson Direct Testimony, at 15.
[8] NCSEA Brucke Direct Testimony, at 11.

for which they are seeking interconnection, and that developers do not carry the obligations of utility service to the using and consuming public.

In my direct testimony, I explained how the Companies' and these solar advocates have differing views on the appropriate allocation of engineering and technical risk, as well as the proper assignment of costs to mitigate those risks, between the Interconnection Customer Generating Facility owner and the Utilities and existing and future retail customers.[9] Public Staff witness Lucas similarly describes the potential for divergence between the interests of the using and consuming public versus interconnection developers.[10]

This difference in perspective between the solar industry and the Companies is analogous to the tension between a city or town imposing setbacks, permitting and other zoning requirements on a homebuilder that could physically locate 10 homes on a piece of property but is limited to seven to avoid adversely impacting the surrounding community. While more dense development may in some cases be physically feasible, the short-term and longer-term risks and burdens of doing so—such as increased water runoff and impacts to already-funded roads, schools and other infrastructure paid for by the general citizenry—would be assigned to existing neighbors and other citizens. This concern becomes even more

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[9] DEC/DEP Gajda Direct Testimony, at 55.
[10] Public Staff Lucas Direct Testimony, at 6.

pronounced when a development boom occurs and the pace of development risks outpacing local zoning and planning. This is not to suggest that homebuilders or solar developers are "bad actors" in any way; however, their interests in developing and interconnecting the largest home development or solar project at the least cost may not align with the interests of the using and consuming public that has funded the infrastructure which they are seeking to use.

Q. DO YOU HAVE ANY OTHER COMMENTS THAT THE COMMISSION SHOULD TAKE INTO CONSIDERATION WHEN EVALUATING THESE SOLAR ADVOCATES' CLAIMS THAT THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE IS ATYPICAL OR OVERLY RESTRICTIVE?

A. Yes. As the Companies have repeatedly stated, with no known challenges to the contrary, we are in a "living laboratory" here in North Carolina, due to the unparalleled penetration of uncontrolled utility-scale generation resources both in operation and in the queue. Assertions that some of the Companies' application of Good Utility Practice do not have parallels in other states are not surprising, since no other states are experiencing the penetration levels of these specific types of resources. Utilities which are not undergoing anything like North Carolina's solar QF development boom, or do not have aggressive renewable penetration mandates in place, may not have begun to consider potential impacts to their system planning obligations. It is for this precise reason that the NC Procedures specifically contemplate that a particular practice may constitute Good Utility Practice even where the practice is not widely applied in the industry.

The Companies are dually responsible for planning and operating the distribution system while also managing the parallel operation of North Carolina's unique, and increasing, penetration of DER. Therefore, Good Utility Practice must absolutely carry with it considerations for scalability and sustainable practices, if the Companies are to continue to provide to the using and consuming public over the long term, "…reliable utility service at reasonable prices within the framework of state and federal law."[11]

Q. DO YOU AGREE WITH THESE SOLAR ADVOCATE INTERVENORS' THAT THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE, AND SPECIFICALLY THEIR DEVELOPMENT OF THE MOS GUIDELINES IS ATYPICAL OR OVERLY RESTRICTIVE?

A. No. Even recognizing North Carolina's unique utility-scale solar development experience, other utilities have established guidelines and technical standards similar to the Companies' MOS Guidelines. NCSEA witness Brucke states that "…Duke's Method of Service Guidelines are not typical…"[12] The Companies note however, that both PEPCO (PEPCO Holdings, which includes Atlantic City Electric in New Jersey, Delmarva

[11] Public Staff Lucas Direct Testimony, at 6.
[12] NCSEA Brucke Direct Testimony, at 11.

Power in Delaware, and Potomac Electric Power in Washington, D.C.)[13] and Arizona Public Service[14] have established guidelines like individual and aggregate DER capacity limits for generators, that are similar to Section 2 of the Companies' MOS. Therefore, the Companies' application of Good Utility Practice and its development of the MOS is not "atypical." Further, while NCSEA witness Brucke argues that the Companies' limit of aggregate DER on a substation as detailed in section 2.1.2 of the MOS is "overly restrictive," PEPCO has a similar limit established which appears to be more conservative than the Companies' limit. Additionally, Dominion Energy North Carolina limits aggregate DER capacity connected to substation transformers to a value similar to the Companies.

Q. PLEASE EXPAND ON THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AND THE MOS GUIDELINES BY PROVIDING AN EXAMPLE OF HOW THE MOS GUIDELINES HELP THE COMPANIES MAINTAIN THEIR LONG-TERM PLANNING OBLIGATIONS TO PROVIDE RELIABLE AND COST EFFECTIVE ELECTRIC SERVICE TO THEIR CUSTOMERS.

A. Consider this example, which relates to the Companies' technical policy related to Line Voltage Regulators ("LVRs"), as is detailed in section 3.2 of

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[13] PEPCO's guidelines are *available at* https://www.pepco.com/MyAccount/MyService/Pages/MD/CriteriaSummary.aspx.
[14] Arizona Public Service's guidelines are *available at* https://www.aps.com/library/solar%20renewables/InterconnectReq.pdf.

the MOS. The first sentence in section 3.2 states "…DEC and DEP have identified that interconnection of uncontrolled utility-scale generation resources with no dependable capacity, at locations beyond LVRs and in high quantities across an entire system, is not consistent with Good Utility Practice." In this policy, the Companies recognize that locating generating facilities in the first zone of voltage regulation, closest to a substation, is more scalable and sustainable than locating facilities further down circuits beyond LVRs. This is because current distribution voltage regulation technology is largely designed for typical distribution loads, which are characterized by voltage drop and by limited volatility of demand. In contrast, multi-MW, distribution-connected independent generating facilities are characterized by voltage rise and by, in most cases, significant volatility of generation output–enough to cause adverse impacts to customers and the regulation equipment itself. This is somewhat manageable in the first zone of regulation, but the impacts of voltage rise and generation output changes become significantly less manageable beyond the first zone of regulation. No power system designer would ever think of a second zone of voltage regulation—many miles from the substation—as a preferred place to site a generating facility. And, even if a specific solution can be designed for a generating facility located beyond an LVR, the solution is not representative of a scalable and sustainable solution, due to the longer-term impacts to distribution planning that would occur absent the MOS Guidelines and the resulting increased costs to retail customers. In the paper "Maintaining Long Rural Feeders with Large Interconnected Distributed Generation,"[15] the author details how special regulator settings were used to interconnect a 9 MW landfill gas generator which was located beyond an LVR. This referenced project was actually interconnected in DEP in approximately 2010. While the initial solution, which involved complex analysis and special regulator settings, was successful, changes in circuit loads only two years after the initial interconnection caused the solution to become obsolete. A new study performed to consider the new retail load indicated that the regulator settings could not be adjusted to accommodate the 9 MW generator and the new 2 MW load simultaneously. The solution was to construct a mile of 3 phase line to support interconnection of the new 2 MW load customer. Importantly, the cost of this local distribution upgrade project was borne by DEP's retail customers. Public Staff witness Lucas describes in his direct testimony more background as to how and why this situation can occur.[16]

NERC also published a report in February 2017, "Distributed Energy Resources – Connection Modeling and Reliability Considerations," in which the authors discuss some of the challenges to long-term planning, and specifically how the "T-D interface" is becoming more crucial.[17] The

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[15] Keary R. Dosier, *Maintaining Long Rural Feeders with Large Interconnected Distributed Generation*, 2014 IEEE Rural Electric Power Conference (REPC) (May 18-21, 2014), *available at* https://ieeexplore.ieee.org/document/6842197 .
[u] Public Staff Lucas Direct Testimony, at 45.
[17] North American Electric Reliability Corporation, *Distribute Energy Resources – Connection, Modeling and Reliability Considerations* (Feb. 2017), *available at*

Companies' careful considerations of long-term planning, one of the main functions of an electric utility, led to the creation of the MOS.

Q. DOES YOUR EXAMPLE REBUT CONTENTIONS MADE BY THE SOLAR ADVOCATES STATING THAT THE COMPANIES' IMPLEMENTATION OF GOOD UTILITY PRACTICE TO DEVELOP THE MOS GUIDELINES WAS UNREASONABLE?

A. Yes. NCSEA witness Brucke contends that "Duke has indicated that interconnection beyond a line voltage regulator is technically feasible if they reconfigure line voltage regulator settings."[18] As an initial matter, the Companies acknowledge that not only is it technically feasible for a specific generator interconnection to reconfigure the LVR settings, but also that the Companies have, years prior to the development of the MOS Guidelines, physically designed this type of interconnection solution for generator interconnection customers several times. The Companies also acknowledge that this practice has been utilized by other utilities in the past. However, recognizing that the Companies now have an unparalleled number of utility-scale generating facilities interconnected to their distribution systems, the Companies determined that this practice is not scalable nor sustainable in high quantities across an entire system for a number of reasons. For example, this practice limits the effective management of distribution

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https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

[18] NCSEA Brucke Direct Testimony, at 7.

circuit switching, increasing its complexity to a level not supported at high numbers by Duke Energy's Distribution Control Center and also not supported by the Distribution Management System currently in place.

Q. ARE THERE ANY ADDITIONAL EXAMPLES YOU CAN PROVIDE THAT MAY REBUT CONTENTIONS MADE BY THE SOLAR ADVOCATES THAT THE COMPANIES' DECISION TO DEVELOP THE MOS GUIDELINES WAS UNREASONABLE?

A. Yes. To touch on one additional item as an example, NCSEA witness Brucke states in his testimony that the Companies' prohibition of double-circuiting "…is not reasonable," [19] as is detailed in section 3.2.4 of the MOS Guidelines. Similar to the prior LVR example explained above, the Companies determined in mid-2016 that allowing "partial double circuits" to support utility-scale generator interconnection was not a scalable nor sustainable practice, as it would lead to many scenarios where certain load growth patterns could no longer be cost effectively served, thereby again pushing undetermined future costs to retail customers.

These instances provide examples of how consideration of scalability and sustainability can impact the application of Good Utility Practice, and how individual generator Interconnection Customers and third-party developers may not understand or appreciate the longer term obligations the Companies have to maintain a highly reliable and cost-

[19] NCSEA Brucke Direct Testimony, at 10.

effective system for the using and consuming public. Further, these examples illustrate the importance of the Companies' need for flexibility to implement Good Utility Practice over time, to efficiently and timely respond to changes in the Companies' power system and in the electric industry as a whole.

Q. HOW DO THE COMPANIES RESPOND TO STATEMENTS THAT THE DEC OR DEP HAVE DENIED INTERCONNECTION FOR SOME INTERCONNECTION REQUESTS?

A. To my knowledge, the Companies have never "denied interconnection outright" as suggested by Witness Brucke.[20] To do so would be inconsistent with how the Companies have interpreted the interconnection-related obligation arising under PURPA, as discussed in section 1 of the MOS Guidelines. Of particular importance, the second paragraph of the MOS Guidelines states:

> DEC and DEP consider all necessary system upgrades to the general electrical system that are required in order to provide distributed energy resources (DER) reasonable and non-discriminatory access to the DEC and DEP distribution systems, the primary purpose of which is to serve existing and future retail customers. As firm retail electric providers, DEC and DEP seek to interconnect DER in a manner that allows each resource to operate within its contractual

[20] NCSEA Brucke Direct Testimony, at 6.

parameters without negatively impacting existing utility customers' quality of service or cost of service. DEC and DEP are not, however, obligated under the NCIP or SCGIP to make modifications that are, or reasonably could be determined to be, detrimental to the operation of its system or detrimental to DEC's and DEP's public service obligations as regulated public utilities or retail electric service providers."[21]

Q. CAN YOU PROVIDE ANY EXAMPLES ILLUSTRATING WHY A DISTRIBUTION SYSTEM INTERCONNECTION MAY BE DETERMINED TECHNICALLY INFEASIBLE, AS OPPOSED TO "DENIED" BY THE COMPANIES?

A. Yes. A common reason for infeasibility is that there are already one or more five (5) MW generating facilities connected to the circuit or substation, meaning the circuit or substation cannot support more power injection (additional MWs).

The reason the circuit or substation cannot support additional MWs of generation may be as simple as excessive voltage rise, or due to other more complex factors. Because voltage rise is caused by the interaction of local generation against the impedance of the entire utility system, a common solution to this locational infeasibility could be to simply reconductor the distribution conductor to a larger conductor. However, if

[21] *See* Rebuttal Exhibit JWG-2, Section 1.

the distribution conductor is already the largest standard conductor size in use by the Companies, and no changes at the substation benefit the voltage issue, then the interconnection will be infeasible due to the specific interconnection location being "DER saturated." Notably, these DER saturated areas are becoming increasingly common in North Carolina's unique interconnection landscape due to the increasing levels of utility-scale solar penetration.

Q. CAN YOU PLEASE EXPAND ON YOUR EXAMPLE AND HOW "DER SATURATION" CAN AFFECT THE FEASIBILITY OF A PROPOSED INTERCONNECTION?

A. Yes. To expand on my example, under a scenario where significant DER interconnects to the point of "saturation," the Companies must still determine what other options may be available for the Interconnection Customer to connect. However, where the local distribution infrastructure is saturated, there are no further upgrades available to be completed to allow for an additional interconnection to existing distribution system infrastructure. Therefore, the Companies may determine that construction of a new distribution substation (sometimes called a "T/D substation" or a "retail substation") is the only option functionally available for the Interconnection Customer to interconnect in that specific location.

The Companies are fully aware of the substantial cost difference between distribution work (such as reconductoring) and construction of a new T/D substation. Reconductoring for a mile or two, when feasible, may cost several hundred thousand dollars, while the cost of constructing a new substation might exceed $5 million. The Companies are further aware that this very large cost difference may impact the project's financials, and thus overall project feasibility. However, while the Companies have always sought to identify the simplest and most reasonable interconnection solution, at the least cost, consistent with Good Utility Practice, the Companies' conclusions will not be altered simply because the outcome is not financially viable for a particular Interconnection Customer.

Q. LOOKING TO YOUR EXAMPLE, ARE YOU STATING THAT NCSEA WITNESS BRUCKE'S ASSERTION THAT THE COMPANIES' ARE DENYING INTERCONNECTION "OUTRIGHT" IS INSTEAD RELATED TO INTERCONNECTION COSTS?

A. Yes. The Companies asked NCSEA witness Brucke via a data request to explain and support this allegation. NCSEA witness Brucke responded that DEC and DEP have always proposed mitigation options but that he "has seen many instances where the mitigation options are financially impractical. For example, if a project is not allowed to interconnect to a distribution feeder as requested, Duke may propose that a new substation be built, and the project connect to the transmission system, which generally would not be financially feasible for a typical 5 MW project."[22]

[22] *See* Rebuttal Exhibit JWG-4 NCSEA Response to Duke Data Request 2-18.

Q. HOW DO YOU RESPOND?

A. The fact that there are no financially feasible interconnection options for a particular project does not constitute "outright" denial of interconnection. Instead, in such cases, it is the unavoidable outcome of the Companies' application of Good Utility Practice in a consistent and non-discriminatory manner. It is the utility's responsibility under the NC Procedures to evaluate the impacts of the proposed generating facility on the distribution and transmission system and to identify any Upgrades required to implement a safe and reliable interconnection (*see* Section 4.3.3 and Attachment 7 System Impact Study Agreement, Section 10, 12). As I highlight above, the Companies' MOS Guidelines establish that the standard for reviewing a proposed generator interconnection is to ensure that the Interconnection Customer will be responsible for any Upgrades required to enable interconnection and parallel operation of the generator "without negatively impacting existing utility customers' quality of service or cost of service." As penetrations increase, more expensive Upgrades such as new T/D substations will be required to interconnect additional generation to already-saturated circuits and substations in certain areas of the Companies' systems. Nonetheless, the Companies commit to providing each Interconnection Customer a technically feasible option for a safe and reliable interconnection at the lowest cost possible, consistent with Good Utility Practice.[23]

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S RECOMMENDATIONS FOR IMPROVING THE PROCESS OF COMMUNICATING NEW CRITERIA MODIFICATIONS FROM THE UTILTIY TO THE INTERCONNECTION CUSTOMERS.

A. Public Staff witness Williamson recommends that in the event of a new screen, study, technical standard, or major modification of technical methodology being developed by the Utilities in their application of the NC Procedures, that the Utilities should be required to: (1) file the new technical standard with the Commission in this docket for information purposes only, (2) immediately post the information on the utility's website, and (3) present the topic for discussion at the next TSRG stakeholder meeting.[24]

Public Staff witness Williamson's further recommends that the Utilities should also inform the Commission of any potential queue impacts, including impacts to (1) Interconnection Request processing time, (2) project withdrawals, (3) and increased interconnection costs to be incurred by Applicants, if known.[25] While the Companies understand and agree with the transparency objective underlying witness Williamson's

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[23] I note that Interconnection Requests for locations close to substations, and on circuits and substations which have not been "DER saturated," still generally allow very straightforward interconnections and are less impacted by the MOS Guidelines.
[24] Public Staff Williamson Direct Testimony, at 24.
[25] *Id.*

recommendation and are always supportive of Interconnection Customers having as much information as reasonably possible, the Companies would be unable to meaningfully comply with these further recommendations.

More specifically, the Companies believe that anticipating and fully addressing and identifying any possible "queue impacts" is infeasible in that it would require the Companies' to use time and engineering resources in making mere hypotheticals and projections concerning the business decisions of third party Interconnection Customers. This is because the Companies will likely not have clear visibility into whether affected project(s) will be more likely to withdraw from the queue due to a new technical standard, and because it will be difficult to quantify if a modification to a technical standard will cause "delays in Interconnection Request processing time." Whether the new standard will result in "increased costs" for most or all Interconnection Customers will also likely be challenging to determine unless the new technical standard or requirement uniformly specifies a particular "solution," such as installing a particular piece of equipment, that will apply to all Interconnection Customers uniformly. Thus, due to the many uncertainties identified above, any projected potential queue impacts would be of little value (particular relative to the amount of resources likely required to conduct the assessment) and could even lead to greater frustration amongst Interconnection Customers when such projections are determined not to be accurate in general or with respect to particular projects.

Q. TO CLARIFY, DO THE COMPANIES' OTHERWISE AGREE TO IMPLEMENT THE PUBLIC STAFF'S RECOMMENDATIONS RELATING TO FILING SUCH REVISIONS?

A. Yes. The Companies' agree to 1) file any significant new screens, studies, or major modification in their application of the NC Procedures with the Commission in this docket for informational purposes only; 2) post information on the utility's website regarding the new screen, study, or modification to the NC Procedures; and 3) present the topic for discussion at the next TSRG stakeholder meeting.

<u>III. Technical Standards Review Group</u>

Q. CAN YOU DISCUSS THE TSRG AND WHETHER THE COMPANIES ARE CONFIDENT THAT THIS STRUCTURE WILL PROVIDE GREATER TRANSPARENCY AND PROMOTE MUTUAL UNDERSTANDING BETWEEN THE COMPANIES AND INTERCONNECTION CUSTOMERS?

A. Yes. Since the TSRG's implementation in early 2018, there have been several meetings held per its intended quarterly meeting frequency, with discussion focused on new interconnection-related developments or planned revisions to the Companies' existing technical standards. The Companies believe the TSRG to be a success, as it has already fostered increased communications and transparency between the Companies' and its Interconnection Customers since the TSRG's inception. Additionally, Public Staff witness Williamson expresses support for the TSRG, stating "the TSRG stakeholder meetings should continue in their current format on at least a quarterly basis for the foreseeable future."[26] Therefore, and as stated above, the Companies and Public Staff both foresee the TSRG as a key tool in communicating new or changing technical standards amongst interested stakeholders.

Q. HOW DO THE COMPANIES' RESPOND TO CERTAIN SOLAR ADVOCATES' CLAIMS THAT THE TSRG HAS BEEN LESS THAN SUCCESSFUL?

A. The Companies disagree that the TSRG has been anything less than successful. Specifically, NCSEA witness Brucke claims that "no changes to any Duke policy or standard have been implemented," since the TSRG was established.[27] This statement assumes that the TSRG is only successful when it results in changes and the Companies do not agree with this assertion. Furthermore, the TSRG is a new creation and therefore it is unrealistic to expect that it will have resulted in significant changes in such a short period of time. To quote the Public Staff, "the TSRG has been beneficial to participants even though it is still in its infancy."[28]

In comparison to the solar advocate interveners, the Public Staff, as evidenced by the above statement, is encouraged by what they have witnessed to-date through their active participation in the TSRG. If one

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[26] Public Staff Williamson Direct Testimony, at 22.
[27] NCSEA Brucke Direct Testimony, at 13.
[28] Public Staff Williamson Direct Testimony, at 22.

reviews the detailed agendas and minutes, which are made publicly available at https://www.duke-energy.com/business/products/renewables/generate-your-own/tsrg and included in my Rebuttal Exhibit JWG-3, one can see the vast breadth and depth of technical issues being raised and discussed at the meetings. Further, much of the Companies' time during these initial meetings has been appropriately spent on educating non-utility TSRG members on the basis and reasons for current practices, systems, processes and procedures—many of which have existed long before the introduction of utility-scale DER.

Q. HAVE THE COMPANIES IMPLEMENTED ANY PROCEDURES RELATED TO THE TSRG AND INCREASING TECHNICAL OVERSIGHT AND UTILITY ACCOUNTABILITY AND CAN YOU PROVIDE ANY EXAMPLES?

A. Yes. The Companies started keeping a detailed action item log and are tracking and following up on discussion items brought to the Companies' attention by interested stakeholders through the TSRG. For example, at the April 2018 meeting, developers asked questions about Salesforce and Powerclerk, and the Companies responded by agreeing to put the issues on the agenda for the July meeting. At the July meeting, the Companies presented information on the status of Salesforce and Powerclerk, in response to these stakeholders' requests. Similarly, at the July meeting, there were many questions raised about voltage management and DSDR and at the October meeting, the Companies provided a summary of how nominal voltage and DSDR are related, and then posted information on the TSRG website under the "meeting three" documents list concerning the same. This action item log, and resulting follow-up communications, shows how the Companies' are taking the TSRG itself, and resulting communications and discussion, seriously in increasing transparency and coordination between the Companies and interested industry stakeholders.

Q. WERE THERE ANY RECOMMENDATIONS MADE BY INTERVENORS RELATING TO THE TSRG'S FUTURE IMPLEMENTATION?

A. Yes. The Companies, the Public Staff, and IREC all support continued implementation of quarterly TSRG meetings. Additionally, IREC witness Lydic recommends that in the future, all TSRG meetings "be publicly noticed and its agenda and meeting minutes be filed in a docket or otherwise publicly posted."[29] The Companies note that the TSRG's meetings already have been and continue to be posted publicly at https://www.duke-energy.com/business/products/renewables/generate-your-own/tsrg, with agendas co-developed by the Companies and the interested stakeholders. Minutes and presentations from each meeting are additionally posted to the Companies' interconnection webpages.

Last, NCSEA and IREC recommend that the current form of the TSRG change to allow for Commission oversight, and discuss a process by

[29] IREC Lydic Direct Testimony, at 23.

which consensus and/or Commission approval would be required for changes to interconnection technical standards.[30]

Q. HOW DO THE COMPANIES' RESPOND TO IREC AND NCSEA'S RECOMMENDATION THAT THE TSRG BE SUBJECT TO COMMISSION OVERSIGHT?

A. The Companies' disagree with IREC and NCSEA that the TSRG should be subject to Commission oversight. In response, I first note that both the Companies and the Public Staff agree that "Duke Energy retains the right to make the final decision on all technical standards or evolving [Good Utility Practice] revisions, subject to Commission review as part of its general regulatory power and the dispute resolution process defined in the NCIP."[31] This approach mirrors the Massachusetts TSRG, on which the Companies' TSRG was based (and which was cited by IREC as a model). The Massachusetts governing documents state that:

> "The members of the TSRG understand and agree that the Utilities have the final decision over which Technical Standards, both common and Utility-specific, to employ for the purposes of interconnecting DG facilities to their respective distribution systems

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[30] IREC Lydic Direct Testimony, at 23; NCSEA Brucke Direct Testimony, at 13.
[31] Public Staff Williamson Direct Testimony, at 23.

> and ultimate control over any Utility-specific and common Technical Standards Manuals they develop."[32]

Thus, other, similar TSRGs do not require Commission oversight.

Further, although the Companies do not dispute the Commission's regulatory powers, to allow Commission oversight of the TSRG would, in essence, give stakeholders a unique ability to assert power over the Companies' internal planning and operating standards. This, in turn, would force the Companies to "re-optimize" power quality, reliability, and economic considerations for retail customers "around" whatever technical standards have been put in place for these solar QF developer stakeholders. Stated another way, today the Companies are free to continually make informed alterations and modifications to their utility system (*i.e.*, provide continual optimization), as long as the cost and quality of service continues to be maintained or improved, given other uncontrolled external constraints. If consensus and/or direct Commission approval were to be required for changes to interconnection technical standards through the TSRG (not including the NC Procedures), the TSRG stakeholders (interconnecting solar QF developers) would be provided first right to alter the Companies' internal practices, and at the cost of retail customers. Therefore, these recommendations should be rejected.

[32] Massachusetts Technical Standards Review Group Final By Laws, *Technical Standards Review Group Guidelines*, at 1, https://drive.google.com/file/d/0B836U49Yrh_QYW5vNGlTR2xrMUk/view.

In conclusion, the Companies believe that the TSRG is a truly valuable and necessary forum in today's emerging world of interconnecting and operating in parallel with growing levels of distributed generation. The Companies also believe that nothing in the current environment changes the effective role of the Commission's long-held oversight and regulatory authority over quality of service and cost of service, and that the Companies, as do all utilities, continue to operate effectively in a mode of continual internal optimization to meet the needs of their retail customers.

IV. IEEE 1547

Q. CAN YOU PROVIDE THE COMPANIES' PERSPECTIVE ON IEEE 1547?

A. Yes. IEEE 1547-2018 represented significant changes to the earlier 2003 version. The new 1547 Standard, titled "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," is not a procedural standard, although it does provide "requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnection." As detailed by Public Staff witness Williamson, "it is not a standard that the Utilities are bound to follow but is a standard that provides guidance on incorporating DER onto the grid."[33]

[33] Public Staff Williamson Direct Testimony, at 17.

Q. CAN YOU PLEASE EXPAND ON THE STATEMENT MADE BY THE PUBLIC STAFF IN REGARDS TO THE IEEE 1547 NOT BEING A STANDARD THE UTILTIIES ARE BOUND TO FOLLOW?

A. Yes. Public Staff witness Williamson's comment is a key point to keep in mind when discussing the IEEE 1547 standard. IEEE 1547 contains the phrase "DER shall…" about eighty-six (86) times, while the phrase "Area EPS shall…" is never included.[34] The import of this DER-focused standard is significant as it allows for utility-specific implementation of Good Utility Practice and does not impose exact requirements, which the Companies' (or any utility) must specifically implement from the IEEE 1547 standard.

However, to keep in line with new developments in the DER industry and to recognize evolving Good Utility Practice, the Companies are studying the new IEEE 1547 standard and working on determining if and when some of the standard's provisions may be appropriate to adopt. Therefore, if and when this becomes the case, the standard will be available for the Companies to utilize in assuring that DER follow all standard designs as called for in the IEE 1547. Until that time, the Companies agree with IREC[35] in that the TSRG is and will be an appropriate forum for

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[34] Note that "Area EPS" refers to the Area Electric Power system, a term meant to refer to the utility.

[35] IREC witness Lydic argues that the TSRG is the appropriate forum for considering smart inverters and the IEEE 1547 standard. IREC Lydic Direct Testimony, at 31-32.

consideration and implementation of the IEEE 1547-2018 Standard, as its use will require coordination with, and action by, North Carolina interconnection developers.[36]

V. Fast Track and Supplemental Review

Q. PLEASE SUMMARIZE IREC'S POSITIONS AS IT RELATES TO FAST TRACK AND SUPPLMENTAL REVIEW.

A. Throughout this proceeding, IREC has placed great emphasis on changing the Fast Track and Supplemental Review process, and raised issues relating to both processes.

Specifically, IREC took positions on:

- the Companies' definition of line section as it applies to Fast Track screen 3.2.1.2;
- changing the Fast Track Eligibility for interconnections on 5 kV circuits, in any location, from 100 kW to 500 kW;
- screening for projects 20 kW and less;
- Supplemental Review screens; and,
- screening criteria for penetration of net-metered DER on a substation transformer.

[36] Notably, questions surrounding "smart inverters" are part and parcel of 1547-2018's scope, and will be taken up in a forum such as the TSRG.

Q. DO YOU AGREE WITH IREC THAT BOTH THE FAST TRACK AND SUPPLEMENTAL REVIEW PROCESSES NEED TO BE REVIEWED AND CHANGED?

A. No. The Companies have seen few issues with the overall Section 3 Fast Track process, and move the majority of Fast Track projects through the queue with relative ease, as compared to the more significant and time-consuming technical and queue challenges related to multi-MW solar farms. Therefore, the Companies believe that both the overall Section 3 Fast Track and Supplemental Review processes are working efficiently at this time and do not need a complete overhaul.

Q. CAN YOU EXPLAIN THE COMPANIES' APPROACH TO EVALUATION OF FAST TRACK SCREEN 3.2.1.2 AND WHY IT DIFFERS FROM IREC'S POSITION?

A. Yes. First, however, I would note that the Public Staff supports the Companies' overall approach to the Fast Track screening process as a whole, including its interpretation of the term "line section" as it evaluates the Fast Track screening criteria.

As background to the Companies' application of Fast Track Screen 3.2.1.2, the Companies developed their interpretation of "line section" using the term "automatic sectionalizing device" as it is classically used in the utility industry. Specifically, the Companies interpret this to apply to a device which is capable of automatically sectionalizing (separating) a section of the distribution system, quickly and without local or remote human intervention. The capability is typically necessary due to a fault, and would include feeder circuit breakers, reclosers, sectionalizers, and fuses. To clarify, there is nothing electrically different about one circuit zone which consists of a transformer fuse, transformer, and several secondary services, as compared with another circuit zone consisting of mile-long fused tap line containing many service transformers and services. As Public Staff witness Williamson stated in support of the Companies' application of this section, "the Utilities are reasonable in using a conservative approach that will results in a higher degree of grid safety and reliability."[37]

In contrast to the Companies' application of this screen, IREC states that the Companies' approach to the 15% peak load screen, and interpretation of "line section" as the zone defined by a service transformer fuse, is too narrow. IREC therefore recommends that the definition of line section include a larger section of the distribution circuit.

In support of their argument, IREC cites a paper titled, "Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies," to justifying its recommendation for a different definition of line section. However, this paper states that "…Automatic sectionalizing devices may include feeder breakers, line automatic sectionalizing switches, and possibly fuses as well." Therefore, this paper acknowledges that a fuse is an automatic sectionalizing device, and therefore also supports the

[37] Public Staff Williamson Direct Testimony, at 13.

Companies' current definition and application of line section within NC Procedures section 3.2.1.2.

The Companies agree with Public Staff witness Williamson that a "…screen should not be arbitrarily adjusted on the sole premise of allowing more projects to pass the screen and be interconnected."[38] The Companies therefore contend that IREC's recommendations should be rejected, as Fast Track section 3.2.1.2 and the current definition of "line section" as applied by the Companies is reasonable and being applied in an efficient manner. All of the above considered, the Companies do however agree with Public Staff witness Williamson that it would be appropriate to address the Companies' application of "line section" within the Section 3.2.12 technical screen during a future meeting of the TSRG, though only so as to increase transparency as to the Companies' interpretation of that term.

Q. HOW DO THE COMPANIES RESPOND TO IREC'S POSITION THAT THE FAST TRACK PROCESS IS NOT WORKING, NOTING HIGH PERCENTAGE SCREEN FAILURE RATES?

A. Most of the screen "failures" are related to the 15% peak load screen, discussed above. As noted in my direct testimony, during the 2017 Stakeholder Process, the Companies shared how the majority of Interconnection Requests proposing to interconnect to the Companies' systems under Fast Track initially fail the Fast Track screens, but are then

[38] *Id.*

successfully evaluated for interconnection through Supplemental Review. Interconnection Customers processed through the Section 3 process are passing Supplemental Review without the Companies identifying a need for full Section 4 study at a rate of approximate 97 percent.

IREC suggested the initial Fast Track screen failures are evidence that the Companies are not applying the Fast Track screens appropriately. However, as I explain in direct testimony, similar logic would lead one to conclude that since the vast majority of college students fail to attain a grade point average in excess of 3.75, university professors must be designing their tests to be too difficult. The Companies maintain that the focus should be on the time for overall processing of Interconnection Requests of certain sizes, regardless of the exact processing mechanism, while technical screens and evaluations should be handled appropriately.

Q. WHY DO THE COMPANIES NOT SUPPORT CHANGING FAST TRACK ELIGIBILITY FOR INTERCONNECTIONS ON 5 KV CLASS CIRCUITS, IN ANY LOCATION, FROM 100 KW TO 500 KW?

A. I would first note that the Public Staff supports the Companies' position to not change Fast Track Eligibility for interconnections on 5 kV class circuits located anywhere on the circuit from 100 kW to 500 kW. Since existing Section 3.1 Fast Track Eligibility Table already establishes an eligibility value of 500 kW for sites within 2.5 miles of the substation, the Eligibility value under question is primarily for facilities further than 2.5 miles from the substation. The reason why the Companies do not support this change in eligibility is primarily based upon physics, which explains why the change is completely unnecessary. As background, most of the Companies' 4160 volt circuit backbones are less than 2.5 miles in length, making an interconnection at a location further than 2.5 miles from the substation exceedingly rare. Hence, the screen value goes mostly unused if eligibility is increased.

As a comparison of distribution circuits: if one assumes 480 amperes of current flow (approximate capacity for a distribution circuit), one would calculate an equivalent voltage drop for a 23 kV feeder of 9 miles in length, a 12 kV feeder 5 miles in length, and a 4.16 kV feeder 1.6 miles in length. As a point of reference, the standard feeder design in DEP, designed in the 1960s, called for the optimum length of a 23 kV circuit to be 9 miles, and the optimum length for a 12 kV circuit to be 5.5 miles, making the point that these are typical feeder lengths even today. Therefore, one should expect few 4.16 kV circuits to be in excess of 2.5 miles in length. In fact, a query of DEC's 4.16 kV circuits across North Carolina and South Carolina estimates 85% of the circuits to be less than 3 miles in length.

Furthermore, a closer inspection of the Fast Track Eligibility table in section 3.1 reveals that it clearly utilizes, as a primary component, the concept of stiffness ratio, and does so appropriately based on the description of stiffness ratio in IEEE 1547.7. Specifically, IEEE 1547.7 describes weak or insufficiently stiff locations on a power system indicative of "…a greater potential to affect system voltage, power quality, and system protection schemes," therefore providing the conceptual basis for deriving appropriate values in the Fast Track Eligibility Table.

As an example, if one were to construct a Fast Track Eligibility Table strictly upon a single stiffness ratio value, and choose a ratio of 60 as the criteria of Fast Track eligibility, the following table would result, based on common parameters of the DEC and DEP systems:

Line Voltage	Interconnection at 3.0 electrical miles from substation	Interconnection at 0.5 miles from substation
4.16 kV	≤ 141 kW	≤ 656 kW
12.5 kV	≤ 0.87 MW	≤ 1.90 MW
24 kV	≤ 1.65 MW	≤ 2.30 MW

Compare this to the actual Fast Track Eligibility table in section 3.1 of the NC Procedures:

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

The similarities of the tables are striking. In comparing these tables, one can see how Interconnection Requests for generating facilities well over 100 kW, up to 500 kW, in locations greater than 2.5 miles from the substation, on 5 kV circuits, will not only be exceedingly rare, but when they occur, have great potential for system reliability impacts that require upgrades and which should be studied in the Section 4 study process.

Although IREC witness Auck believes that IREC's eligibility proposal is now a "…*de facto* national standard…"[39] and points to the state of Ohio—where Duke Energy Ohio[40] operates—adopting a 500 kVA threshold for this screen, the Companies assert that this change has virtually no positive effect to the processing of interconnection requests, and will be rarely, if ever used. Additionally, in the Companies' opinion, compliance with a supposed "…*de facto* national standard…" is insufficient as a singular justification when the engineering and physics behind the screen involved do not offer support.

Q. WILL THE COMPANIES PLEASE CLARIFY THEIR PRACTICES FOR SCREENING PROJECTS 20 KW AND LESS?

A. Yes. First, I would like to make a clarification concerning recent filings and data requests made by the Companies which referenced the use of a "Demand Table" in its evaluation of projects ≤ 20 kW. To be clear, the Companies use this "Demand Table" to confirm compliance with the NEM tariffs in DEC and DEP, not to evaluate interconnection impacts. The NEM

[39] IREC Auck Direct Testimony, at 19.
[40] The Companies note that to their knowledge, Duke Energy Ohio did not support this eligibility change before the Public Utilities Commission of Ohio.

tariffs in DEC and DEP require that the capacity of the generating facility must not exceed the Customer's estimated maximum annual kilowatt demand, and the "Demand Table" is composed of estimated kW demand levels based on attributes of the customer's home. The data in the "Demand Table" is sourced from the Company's design information, which it uses to size service transformers, secondary service cables, and other electrical equipment. Therefore, the "Demand Table" is not specifically germane to the discussions around interconnection impact evaluation.

Turning to the actual screening of Interconnection Requests ≤ 20 kW in size, to-date the Companies validate that the Interconnection Customer is utilizing equipment which is UL1741 listed for its <20 kW project. Notably, having proper UL1741 equipment is the most important safety and operational aspect for these sized interconnections. The Companies have not, however, performed Section 3 Fast Track screening for all 4,000+ Section 2 Interconnection Requests. Previously, the Companies evaluated the Section 3 screens and concluded, in conjunction with their knowledge and experience of small inverter-based facilities, that no safety risks and little to no operational risks would occur if initial Section 3 Fast Track screening was not completed. Instead, the Companies' evaluation concluded that application of the Section 3 screen to such small projects would rather result in a laborious process with little to no benefit to Interconnection Customers or to the protection of power quality and reliability on the system.

Q. WHY DO THE COMPANIES NOT SUPPORT SIGNIFICANT CHANGES TO THE SUPPLEMENTAL REVIEW PROCESS?

A. The current Supplemental Review process provides valuable flexibility for both the Utility and the Interconnection Customer. Additionally, the Companies have utilized the Supplemental Review process with much success; when a project fails to pass one or more Fast Track screens, the project most often proceeds to Supplemental Review where it is then successfully evaluated. In many cases, Fast Track-eligible projects require additional technical evaluation but do not need to undergo the Section 4 study process to ensure they can be safely and reliably interconnected. However, larger projects or locations with more complexity may be referred to the Section 4 study process to assure that circuit impacts of interconnecting the proposed Generating Facility are well-understood before proceeding to an Interconnection Agreement.

While IREC claims that the Companies' use of discretion "provides a ripe opportunity for the appearance of, or actual, discriminatory treatment of projects,"[41] the Companies initially note IREC witness Auck's testimony that they are legally prohibited from exercising discriminatory treatment of projects, and second, even question why or to what end they would engage in such discriminatory treatment. From the Companies' perspective, there

[41] IREC Auck Direct Testimony, at 17.

appears to be no obvious incentive to do so, and the Companies therefore reject IREC's unsupported contention.

Q. WHY DO THE COMPANIES NOT SUPPORT IREC'S PROPOSAL FOR THE IMPLEMENTATION OF ADDITIONAL SCREENS WITHIN THE SUPPLEMENTAL REVIEW PROCESS?

A. The Companies' do not support IREC's proposal for a set of three prescriptive Supplemental Review screens in lieu of the current, more flexible approach the Companies advocate to continue to implement. The Companies first reject IREC's proposal because the addition of standardized screens to the Supplemental Review process implies that there is a complete and uniform understanding of every possible future design of DER and how it might connect to the distribution system. Secondly, IREC's proposal assumes that distribution systems in North Carolina are 100% equivalent to distribution systems elsewhere. Neither premise is correct.

Rather than adopting new screens within the Supplemental Review process, the Companies instead would support further evaluation of the Fast Track process screens, taking into account the specifics of the distribution systems involved, as well as industry developments. The Companies' recently formed TSRG can provide a forum to evaluate whether a more well-defined Supplemental Review process would create benefits over the current flexible Supplemental Review process that exists today.

Further, although IREC contends that these Supplemental Review screens will increase efficiency—seemingly because customers know what to expect and can assess earlier on whether their project would pass screens—the Companies' evaluation of these proposed screens shows the opposite conclusion; acceptance of these additional screens would in fact decrease efficiency. As detailed in my direct testimony, a few of IREC's proposed screens mirror the Companies' current Supplemental Review process, while others do not provide much value to Interconnection Customers at all, meaning these screens would only further delay an Interconnection Customer's processing through the queue.

Further, the Companies in their experience find that the relative small cost of a Fast Track review and Supplemental Review, in comparison to the cost of the project, incentivizes Interconnection Customers to complete the study and interconnection process as swiftly as possible, in order to be aware of the final outcome and any related costs of their proposed project, prior to fully committing to construction and final operation. Thus, the Companies' current study process, is developed organically to only address the items which need to be studied for a safe and reliable interconnection and nothing further. In conclusion, the Supplemental Review process as it exists provides the Companies more latitude to continually improve and optimize the evaluation process, a concept which comes natural to a utility in almost everything it does, and provides benefit to all Interconnection Customers.

Q. CAN YOU PROVIDE ANY EXAMPLES OF HOW THE FLEXIBILTIY OF THE CURRENT SUPPLEMENTAL REVIEW PROCESS HAS IMPROVED NORTH CAROLINA'S INTERCONNECTION PROCESS?

A. Yes. The Companies note how IREC witness Lydic questions the Companies' use of a 10% screen in which the aggregate amount of net-metered DER on a substation is calculated to see if it is below 10% of the substation transformer capacity, within Supplemental Review. This is actually a great example of the Companies' organically developing flexible evaluation methods to move projects through the queue as swiftly as possible, while also making sure certain impacts are not missed.

Specifically, this 10% screen was developed so that the Companies could flag growing penetration of net-metered DER on substations, and perform additional study if needed. It was created with the knowledge that conservatively, the minimum load experienced by most all transformer banks would be at least 10% of the bank's rating. This screen also has allowed most net-metered projects to move quickly through evaluation as this screen was satisfied.

In using and developing flexible evaluation methods, the Companies are utilizing internal engineering talent to identify what is needed specifically on the Companies' systems, with the Companies assuming any and all risk which may come with improper technical evaluations. In any case, the Companies' more "personalized" evaluation is better than evaluation through a set of screens handed down from elsewhere and not taking into account specifics of the Companies' systems.

Further, since the Companies are completely responsible for reliability and power quality on their systems, the Companies are best able to process interconnection requests with flexibility in its evaluation processes. The risk of such processes being too lenient or liberal are taken on by the Companies, while the risk of such processes being too conservative or restrictive are addressed by offering full transparency of its methodologies and availability for discussion through the TSRG. Finally, the reason to maintain these processes as flexible and not lock them down is that this is a dynamic and changing area of study. Handling these issues within the TSRG rather than specifically in a regulatory document is more efficient for all stakeholders and presents no disadvantages for stakeholders.

VI. Material Modification

Q. PLEASE ADDRESS THE COMPANIES' POSITION ON MATERIAL MODIFICATIONS, ESPECIALLY WITH RESPECT TO ENERGY STORAGE.

A. NCSEA witness Brucke and NCCEBA witness Norqual both testify that an Interconnection Customer should be able to add energy storage to an Interconnection Request already in the queue. As background, during Working Group #2 in the 2017 Stakeholder Process, language was agreed upon which called for the ability to make changes to the DC system configuration of a facility, without them being considered "indicia of a material modification." In addition, the Interconnection Request form was revised to call for hourly production profile information. Both of these changes can be seen in the final markup of the NC Procedures as compiled by Advanced Energy and filed with the Commission by the Public Staff in August of 2017. As explained throughout the 2017 Stakeholder Process, the Companies' concerns are with modeling accuracy and system impacts of battery storage, and assuring that what is being studied actually matches the reality of the generating facility's impact to the system, especially where otherwise material changes are subsequently made to the facility design.

Despite this seemingly unassailable perspective, NCCEBA witness Norqual questions the Companies' addition of a phrase in the NC Procedures Redline, as filed with my direct testimony. Specifically, the following section 1.5.2.5 reads as follows, with the additional text submitted by the Companies underlined:

> 1.5.2.5 A change in the DC system configuration to include additional equipment that does not impact the Maximum Generating Capacity, daily production profile or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, static VAR compensators, power plant controllers, and energy storage devices such that the output is delivered during the same periods <u>and with the same profile</u> considered during the System Impact Study.

The Companies realized after the conclusion of Working Group #2 that the 1.5.2.5 language likely left open for interpretation whether an Interconnection Customer could generate at the originally requested full output at any time between sunrise and sunset, the assumed operating hours of a solar farm. The assessment of exactly what hours of the day, and to what levels, of energy storage production might be a permissible modification, without performing additional study, would be subjective at best. Without being able to perform proper studies to re-assess the impacts of the modified generator + storage output, the Companies risk inadvertent discriminatory treatment across Interconnection Customers. Study complexity is growing, not diminishing, and an uncontrolled storage device could be in a charge state, discharge state, or neutral state at any time. Any study must be able to account for what will truly happen in reality.

Therefore, the Companies added the words "and with the same profile" to the Advanced Energy redline simply out of an abundance of caution. This was necessary because operation at full requested output early or late in the day, for example, when studies have been assuming solar output has been very low, cannot be supported by original study assumptions. Although this should be well understood, the Companies believe the clarifying language is necessary to ensure system safety and reliability.

Additionally, I note that it is true that the NC Procedures allow for some changes to the DC configuration without concern for production profile, such as DC/AC ratio increases. These DC/AC ratios are known to impact early and late day ramping, a growing concern of its own, though the Companies manage the concern through requirements or other mitigation if system ramping becomes sufficiently impacted. However, the addition of energy storage is not analogous to a DC/AC ratio increase. The Companies expect modeling to become more complex in the future, and without assurances the original profile can be maintained with the addition of battery storage, the Companies must consider profile changes as "material" when and where they do impact study assumptions.

VII. Software Controls

Q. PLEASE ADDRESS THE COMPANIES' POSITION ON THE REVISED NCIP SECTION 6.10.2, WITH RESPECT TO SOFTWARE CONTROLS.

A. Yes. IREC witness Lydic, claims that the phrase "mutually agreed upon" as included in Section 6.10.2, presents concern in that it could allow the Utilities to limit controls to only physical controls. Importantly, the Companies already rely upon software-based controls, for example when inverters in solar farms are programmed with appropriate "Pmax" (maximum real power output) settings to assure that the sum total of inverter output does not exceed the contract capacity. Conversely, solar farms utilize power plant controllers (which are programmable devices and have attributes of software-based controls) to control output as well. Therefore, the phrase "mutually agreed upon" should not present problems for

Interconnection Customers looking to use software controls to manage power export. However, the Companies note that proper output controls are extremely important as they control impacts to retail customers on distribution circuits, and on the transmission system for transmission interconnected generating facilities. Therefore, the Companies will continue to review and agree upon appropriate export controls proposed by Interconnection Customers.

VIII. Completion of an Independent Review of the NC Procedures

Q. WHAT IS THE COMPANIES' POSITION ON THE PUBLIC STAFF'S RECOMMENDATION FOR AN INDEPENDENT REVIEW OF THE NC PROCEDURES?

A. The Companies do not support a full independent review of the NC Procedures. A full independent review would likely consume significant time in 2019, and is broader than the Companies would support as reasonable and beneficial based upon the recently-completed 2017 Stakeholder Process and the Commission's review of the NC Procedures review that is already underway. As discussed in greater detail by DEC/DEP witness Freeman, significant work will already be required in 2019 to transition the study process for larger generators from the current serial process to a cluster study approach. Requiring the same Duke Energy team to also coordinate a separate independent review of the full NC Procedures in parallel (on top of their actual "day jobs" of administering the interconnection process) would be nearly impossible and potentially delay or impair the implementation of needed queue reforms. This is especially the case if the Public Staff is contemplating "significant stakeholder input" into the independent review process. At a minimum, the Companies would request that such a study be delayed until after the grouping study stakeholder process is concluded.

While the Public Staff appears to assert that independent review of the entire interconnection procedures is "common,"[42] Public Staff only cites to one analogous example, New York's independent review. The Companies have reviewed the EPRI report on the New York interconnection standards, and note that New York's review was part of that state's overarching "Reforming the Energy Vision" process. Notably, New York's then-existing interconnection standards only applied to generators up to 2 MW, meaning New York's interconnection procedures and pre-existing landscape was in a much different place than North Carolina's today. Additionally, although the Companies tried to find the cost of EPRI completing its assessment and developing this 100+ page report for New York, we have been unable to do so and also note that the cost of such a review is a concern. The Companies are not aware of any other state having undertaken a third-party review on such an enormous scale.

As I explain in my direct testimony, the Companies continue to support a more narrowly-focused independent review or consultation with

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[42] Public Staff Williamson Direct Testimony, at 27.

ERPI on the Fast Track and Supplemental Review process.[43] This could be implemented through the TSRG, with industry participation and feedback provided through the TSRG. However, a "full NC Procedures review" with stakeholder input would be unduly burdensome to implement at this time, would impair the Companies' ability to perform other functions (including efforts to implement a full grouping study), would likely be costly, and should therefore be rejected or at least postponed by the Commission.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[43] DEC/DEP Gajda Direct Testimony, at 36.

BY MR. JIRAK:

Q Mr. Gajda, do you have a summary of your testimony?

A I do.

Q Would you please proceed at this time?

A Yes.

(WHEREUPON, the summary of JOHN W. GAJDA is copied into the record as read from the witness stand.)

Testimony Summary – John W. Gajda

Docket No. E-100, Sub 101

January 28, 2019

Chairman Finley, Commissioners, good afternoon. My name is John Gajda, and I work as a power systems engineer at Duke Energy. I am glad to be here today to help shed light on Duke Energy's recommended modifications to the North Carolina Interconnection Procedures as well as to provide my perspective more generally on the unique interconnection landscape in North Carolina.

I would like to begin by briefly highlighting a few aspects of my background that I believe give me a unique perspective in this proceeding. Twenty of my last 28 years in full time practice as an engineer have involved generator interconnection design work for distribution, sub-transmission, and transmission interconnections. I started work at Duke Energy – then Progress Energy – in 2001, and since 2003 have continuously had some amount of responsibility for generator interconnections.

I currently serve as an internal consultant for Duke Energy for most all technical matters surrounding distribution and transmission interconnections. From 2014 until 2018 I served as Manager and then Director of the DER Technical Standards group in Duke Energy, where I led a group of engineers involved in providing technical leadership and guidance for interconnection study methods and procedures. During that time, as DER penetration rapidly increased, I led much of our establishment and refinement of necessary technical standards and policies to assure that interconnections could sustainably continue alongside our critical distribution & transmission planning processes.

My pre-filed direct and rebuttal testimonies provide technical perspective on Duke Energy's interconnection efforts and challenges faced over the past few years. Make no mistake, the pace of change has been breathtaking as I and many other personnel within Duke have worked tirelessly to establish sustainable interconnection practices—practices that have resulted in national-leading amounts of interconnections—while also ensuring reliable power for all customers, all within the so-called "living laboratory" that is North Carolina interconnection.

We often refer to North Carolina as a "living laboratory" because no other state has attempted to interconnect such a vast amount of utility scale generation to its distribution system. When I have explained to utility engineers at technical conferences what we have been experiencing in North Carolina, I have been consistently met with stunned amazement as I have described the pace, size, and quantity of the facilities we have been and continue to connect to the distribution system. Because of the unprecedented nature of the interconnections in North Carolina, it has been necessary to evolve and develop policies and procedures in the midst of this surging growth that not only ensure the sustainability of our interconnection practices in the short term but also ensure that what we do today does not inequitably constrain future distribution system flexibility and thereby increase costs to all customers. It is vital to understand that the distribution system—unlike the transmission system—was never designed to allow for the two way flow of power and there will remain challenges to the Companies in the future as it seeks to plan, operate and maintain a distribution system that now also provides transmission-like services.

Nevertheless, it is essential that Duke have sustainable methods in place to still allow utility-scale generators on the distribution system in the future, when they do occur.

In my testimony, I discuss the participation of Duke Energy's team in the recent Advanced Energy ("AE")-led interconnection stakeholder process, held in late 2017, to consider changes needed to the Interconnection Procedures. I provide to the Commission Duke Energy's proposed modifications, and explain why Duke Energy does not support the idea of major overhaul to sections of current Fast Track and Supplemental Review process. I have personally been involved in performing multiple interconnection studies and I can confidently say that my and Duke's consistent focus has always been on results – for the interconnection customer and protection of the retail customer – rather than worrying so much about aligning parts of the interconnection standards with other states. As I look in my local perspective just here in DEP, I recall that in 2010, we had less than 20 MW of utility-scale DER, greater than 1 MW each, on the *distribution* system. Today I see over 1400 MW of this DER in just DEP, and am phenomenally proud of having accomplished something no other utility in the country – or the world – can quite lay claim to, and know that our approach of relying on results has been more than successful.

While I am not going to summarize every technical point in my testimony, I do want to highlight a few points for the Commission's benefit. Recall that the interconnection procedures are structured in a "staged" manner, to generally provide faster processing for smaller projects of lesser consequence, while also providing for more in-depth analysis for larger projects which may involve impacts and solutions to mitigate those impacts.

We have and continue to connect small, non-utility scale generators successfully with little fanfare and few complaints, and hence we do not support changes in the state's procedures for these types of interconnections. One intervenor wishes to see North Carolina conform to the requirements in some other states, in an effort to create a "national standard," but this is not necessary in order to efficiently serve interconnection customers and protect retail customers' reliability and power quality.

For larger projects, discussions took place during the stakeholder process to address the Procedures' "Material Modification" section. This section establishes the process when an interconnection customer elects to alter their design after the project has entered the queue, and sometimes after it has entered the study phase or even executed an interconnection agreement. These provisions allow for inconsequential changes to the project to be allowed. But where changes of consequence are made after a study is underway or completed, ones which would require a "re-study" for a project in order to determine impacts to its own project and later-queued projects, a determination of "Material Modification" moves the study of such changes to the end of the queue, thus preventing slowdown of the queue and any impacts to later-queued projects.

"Working Group #2," during the stakeholder process, worked out a number of consensus changes to this section. There have been comments from intervenors which lead Duke to believe that these parties wish to add energy storage to facilities already in the study process, or already interconnected, without requiring additional study. From an interconnection perspective, Duke's position is not that the addition of storage should not be permitted but rather that the addition of storage requires further study in order to ensure reliability and proper cost allocation. This is because a solar plus storage facility has the potential to operate in ways that are substantially different than a solar-only facility, therefore invalidating certain key assumptions the Companies makes when we study solar-only resources.

With respect to the Companies' interconnection policies and methodologies, there has undoubtedly been differences of opinion at times between the solar development community and Duke. But the fact that there have been differences in opinion should be unsurprising given the different perspectives of the parties. We have appropriately focused our efforts on education in recent years, and in my testimony I have discussed Duke's efforts and progress in fostering transparency and improved technical understanding of the Companies' evolving interconnection standards and technical requirements, including through the recent formation in April 2018 of the Duke Energy-led Technical Standards Review Group, or TSRG, which provide additional opportunities for full and frank dialogue on various technical issues. In fact, Duke held the fourth Carolinas TSRG meeting just last week, on January 23.

In conclusion, as I have lived on the front lines of North Carolina's living laboratory, I am proud of the ways in which the Companies have achieved national-leading amounts of interconnections. Through this journey, the Companies have been identifying and implementing reasonable, non-discriminatory policies to assure we continue to meet our dual obligation of serving current and future retail customers, and of serving current and future generators on the distribution system.

Commissioners, this concludes my summary.

MR. BREITSCHWERDT: Thank you, Mr. Gajda.

DIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q Good afternoon, Mr. Riggins. Would you please state your business -- your name and your business address for the record?

A My name is Jeffrey W. Riggins. My address is 400 South Tryon Street in Charlotte.

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

A I work with Duke Energy. I'm the Director for Generator Interconnections and Standard Purchase Power Agreements.

Q And did you cause to be prefiled in this docket on November 19, 37 pages of direct testimony in question and answer form?

A Yes.

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

A Yes. I have one correction.

Q Would you please inform the Commission of that correction at this time?

A Yes. On page 21, line 5 of my direct testimony I incorrectly identify the under-recovery of Category 1 fee related expenses for 2017. The figure one million six hundred and thirty five thousand -- $1,000,635 should be replaced with $871,674. The corrected figure is also reflected in my rebuttal testimony in Exhibit JWR-3.

Q Thank you, Mr. Riggins. And if I were to ask you the same questions that appear in your direct testimony subject to that correction today, would your answers be the same?

A Yes.

Q And did you subsequently also cause to be prefiled in this docket on January 8, 2019, 58 pages of rebuttal testimony in question and answer form and five exhibits?

A Yes.

Q And was Rebuttal Exhibit JWR-4 subsequently refiled on January 11th to redact certain information as confidential?

A Yes.

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

A I do not.

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

A Yes.

Q Thank you.

MR. BREITSCHWERDT: Mr. Chairman, at this time I would move Mr. Riggins' prefiled direct and rebuttal testimony into the record and pre-mark his five rebuttal exhibits, including the confidential information that was refiled in his JWR Rebuttal Exhibit 4, pre-mark those for identification as prefiled.

CHAIRMAN FINLEY: Mr. Riggins' direct prefiled testimony of November 19, 2018, of 37 pages, as corrected, is copied into the record as though given orally from the stand. And his rebuttal testimony of January 8, 2019, of 58 pages is copied into the record as though given orally from the stand. And his five rebuttal exhibits are marked for identification as premarked in the filing with 4 being refiled with some confidential information noted in it.

MR. BREITSCHWERDT: Thank you.

(WHEREUPON, the prefiled direct testimony of JEFFREY W. RIGGINS as corrected is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**DIRECT TESTIMONY OF**
Petition for Approval of Generator	)	**JEFFREY W. RIGGINS**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey W. Riggins, P.E. and my business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?

A. I am the Director of Standard Power Purchase Agreements ("PPAs") and Generator Interconnections for Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science in Electrical Engineering in 1988 from Clemson University and a Master of Business Administration in 2012 from Queens University of Charlotte.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. Throughout my 30-year career at Duke Energy, I have held multiple positions with increasing responsibilities in distribution, transmission, telecommunications, emergency preparedness, and now, distributed energy technologies. I have experience in engineering, account management, project management, and have held various departmental leadership roles within Duke Energy.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In August 2016, Duke Energy's Distributed Energy Technologies ("DET") organization established my current role to provide targeted management of Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP" and together with DEC, the "Companies") administration of the generator interconnection process in North Carolina and South Carolina. In this role, I am responsible for the administration of the interconnection process for both distributed generation and traditional generation resources requesting to interconnect to the Companies' transmission and distribution systems. This includes administering the "processing" and customer coordination of generator interconnections under the North Carolina Interconnection Procedures ("NC Procedures"), the South Carolina Public Service Commission-approved South Carolina Generator Interconnection Procedures, and the Federal Energy Regulatory Commission ("FERC")-approved Large and Small Generator Interconnection Procedures. I am also responsible for interconnection processing in other Duke Energy jurisdictions in Florida, Ohio, Indiana, and Kentucky.

My team is specifically responsible for processing Interconnection Requests, handling interconnection customer communications, and coordinating with subject matter experts ("SMEs") from a number of organizations within Duke Energy to ensure a robust, thorough analysis of potential impacts of interconnecting a proposed generating facility or "project" to the DEC or DEP transmission/distribution grid. After the study process is completed, my team is then responsible for execution of both state and FERC jurisdictional Interconnection Agreements as well as "Schedule PP" standard offer PPAs entered into under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Once a project has completed the study process, executed an Interconnection Agreement and PPA, and is interconnected to the grid, my team manages the Companies' ongoing contractual relationships with the projects under the various agreements.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. No. I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to inform the Commission regarding the Companies' ongoing efforts to administer the interconnection process under the NC Procedures and to support the Companies' proposals to modify certain provisions of the currently-approved NC Procedures. My testimony first highlights the Companies' recent participation in the 2017 stakeholder meetings on the NC Procedures as well as efforts since the Companies formed the Distributed Energy Technologies organization in 2016 to add additional dedicated resources to administer the interconnection process. I also discuss a number of Duke Energy-supported proposed modifications to the NC Procedures. These proposals include increasing certain deposits and fees to more fully recover the Companies' interconnection-related costs; modifying the current dispute resolution process; and recommending the Commission adopt limited, targeted modifications to the interconnection study process, including: (1) enhancing scoping meetings, (2) establishing timeframes for decisions and responses from Interconnection Customers during the study phases, (3) facilitating more expedited interconnection studies for swine and poultry projects and standby generators that momentarily parallel the electric grid.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

I. 2017 Stakeholder Process and Efforts to Support Generator Interconnection in North Carolina

II. Recovering Interconnection Related Costs

III. Interconnection Processing Proposals

IV. Dispute Resolution

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. No. I am not.

I. 2017 STAKEHOLDER PROCESS AND EFFORTS TO SUPPORT GENERATOR INTERCONNECTION IN NORTH CAROLINA

Q. PLEASE DESCRIBE THE COMPANIES' PARTICIPATION IN THE 2017 STAKEHOLDER PROCESS.

A. Pursuant to the Commission's May 15, 2015 *Order Approving Revised Interconnection Standard*, the Public Staff—North Carolina Utilities Commission ("Public Staff") initiated, and Advanced Energy ("AE") facilitated, the 2017 stakeholder process. The stakeholder process provided a structured and open forum for the Companies, the Public Staff, Dominion

Energy North Carolina ("Dominion"), North Carolina Electric Membership Corporation, numerous solar developers, and other stakeholders to share their perspectives on the successes and ongoing challenges under the 2015 revisions to the NC Procedures, while working toward common ground on proposed revisions to the NC Procedures. Throughout the summer and fall of 2017, the Companies actively participated in these meetings and worked in good faith with Interconnection Customers and other stakeholders to identify reasonable and beneficial opportunities to improve the NC Procedures.

As part of the 2017 stakeholder process, AE also convened four Working Groups to support targeted discussions of interconnection-related topics such as study process transparency, new technology issues, utility construction and design standards, and conflict resolution. The Companies actively participated in all four of the Working Groups, with Duke Energy Witness John Gajda leading Working Groups three and four. Several other Duke Energy representatives, including myself, actively participated and contributed in both the broader stakeholder meetings and targeted Working Group meetings representing our account management, financial, and study teams.

Q. PLEASE HIGHLIGHT SOME OF THE ISSUES AND CONCERNS THE COMPANIES RAISED DURING THE STAKEHOLDER PROCESS.

A. During the stakeholder process, the Companies raised concerns about interconnection fees and deposits; ongoing challenges managing the unparalleled volume of utility-scale power export interconnection requests (largely 5 MW_{AC} solar projects); the process and standard for determining what constitutes a "Material Modification;" and the lack of adequate provisions to establish clear timeframes for developer decisions or responses during the study phases under the Section 4 study process. Throughout the stakeholder process, the Companies listened and collaborated with the Public Staff, solar developers, and other parties to address these concerns and subsequently proposed changes to address a number of these concerns through a joint utilities redline of the NC Procedures.

Q. PLEASE HIGHLIGHT SOME OF THE ISSUES AND CONCERNS RAISED BY DEVELOPERS DURING THE STAKEHOLDER PROCESS.

A. Developers recognized that the Companies continue to be challenged to manage the volume of utility-scale interconnection requests and expressed frustration about delays in the interconnection process. Developers also raised a number of issues, including concerns about the Companies' new and increasingly stringent technical standards and requirements, transparency regarding project status, how the Companies process Fast Track and Supplemental Review requests, and the definition of "Material Modification."

In response to many of the concerns, the Companies proactively changed some of their processes and continue to voluntarily make improvements to support the interconnection process. For example, based on stakeholder feedback, the Companies proactively began providing more detailed System Impact Study reports to improve transparency. They also began expanding (1) the level of detail in interdependency letters and mitigation option notices, (2) the level of detail in pre-application reports to identify known constraints such as regulators and voltage issues, and (3) the scope of Supplemental Review to allow projects requiring more minor construction to install reclosers to be approved through Section 3 rather than requiring a full system impact study under Section 4. Other ongoing process improvements include integrating technology into the interconnection administration process and implementing the use of reminders in Salesforce to better track milestones.

Q. RECOGNIZING THAT INTERCONNECTION STAKEHOLDERS EXPRESSED FRUSTRATION ABOUT INTERCONNECTION REQUEST PROCESSING DELAYS, CAN YOU PLEASE BRIEFLY DESCRIBE THE COMPANIES' EXPERIENCE MANAGING THE INTERCONNECTION PROCESS?

A. Yes. As more generally discussed by Duke Energy Witness Gary R. Freeman, the Companies are and always have been committed to making reasonable efforts to process Interconnection Requests in accordance with the NC Procedures. I am proud of the efforts the Companies have made to support safe and reliable interconnections both for our customers under the Section 2 and Section 3 study process, as well as for the hundreds of developer-sponsored multi-megawatt solar facilities that have requested to interconnect to the Companies' distribution and transmission system in North Carolina. While the Companies have generally maintained compliance with the timeframes for studying smaller retail customer-sited generating facility interconnections under the Section 2 and Section 3 study process, the Companies recognize that DEC and DEP have been challenged to complete certain steps of the Section 4 study process, especially the Section 4.3 System Impact Study, within the timeframes contemplated by the NC Procedures. Despite these challenges, the Companies have made, and will continue to make, diligent and good faith efforts to efficiently and fairly process all Interconnection Customers' Interconnection Requests pursuant to the NC Procedures. The Companies' efforts are borne out by the number of generator interconnections that have actually been accomplished since the Commission approved the NC Procedures in May 2015. During this period, the Companies have supported approximately 4,600 retail customer interconnections of small solar and other customer-site generating facilities up to 20 kW and have also entered into over 350 Interconnection Agreements with larger generating facilities above 20 kW.

Q. PLEASE DESCRIBE THE COMPANIES' INCREASING RESOURCE COMMITMENTS TO THE NORTH CAROLINA INTERCONNECTION PROCESS FROM 2015 TO 2018.

A. The Companies have invested significant time and resources to respond to the rapidly evolving interconnection process and to meet the growing demands from Interconnection Customers, both large and small. Beginning in 2016, Distributed Energy Technologies established additional leadership positions and reorganized jurisdictional teams in DEC and DEP to provide more focused administration of the interconnection process. The management team monitors the need for staffing based on expected volumes and current backlog and adjusts resources as needed.

The Distributed Energy Technologies team—which manages Interconnection Customers greater than 20kW—has grown to now consist of separate DEC and DEP Managers, nine Account Managers, six Contract Analysts, and four Customer Account Specialists. This team is fully dedicated to coordinating the Section 3 "Fast Track and Supplemental Review" and Section 4 "full study" interconnection process from start to finish, including coordinating System Impact Studies and Facilities Studies. In addition, this team is responsible for preparing and executing Interconnection Agreements, tracking progression of projects through the study process, collecting fees, milestone payments, and other deposits to help a project progress through the queue, coordinating construction of interconnection facilities and system upgrades, and generally engaging in ongoing communications with Interconnection Customers.

Q. ON TOP OF EXPANDING AND REORGANIZING THE DISTRIBUTED ENERGY TECHNOLOGIES TEAM, HAVE THE

COMPANIES ESTABLISHED ANY NEW GROUPS TO HELP MEET GROWING CUSTOMER DEMANDS TO INSTALL RENEWABLE ENERGY?

A. Yes. The Companies have also established a separate retail customer-focused Renewables Service Center ("RSC") to support the needs of our residential and commercial customers looking to install a generating facility at their home or business. In addition to processing and managing Section 2 interconnection requests, the RSC also reviews and validates the Interconnection Requests for all utility scale projects, both state and FERC-jurisdictional, and assigns a queue number when the Interconnection Request is complete. The RSC is a dedicated interconnection customer service organization focused on processing the already-significant and increasing volume of Interconnection Requests received in North Carolina and across Duke Energy's other jurisdictions.

Duke Energy has also recently formed a new distributed generation ("DG") engineering organization dedicated to managing distribution-level interconnection studies. Currently the DG team includes a team manager, 5 engineers, and plans to add 3 additional team members over the next few months. This new internal DG team will supervise and coordinate with other internal Duke Energy SMEs, as well as the approximately 40 dedicated contractor study engineers conducting System Impact Studies for state jurisdictional distribution interconnection projects in North Carolina and South Carolina.

Q. CAN YOU PROVIDE DETAILS ON THE INTERCONNECTION-RELATED RESOURCES THE COMPANIES HAVE ADDED SINCE 2015 TO BETTER MANAGE THE GROWING VOLUMES OF INTERCONNECTION CUSTOMERS?

A. Yes. As noted earlier, the Distributed Energy Technologies, RSC, new DG team, and study teams have significantly increased overall staffing to support generator interconnections over the past four years. Figure 1 details the increasing number of resources dedicated to supporting the interconnection process in the Carolinas from 2015 to today.

Figure 1

	1/1/2015		1/1/2017		9/1/2018	
Dist. Energy Tech.	5	AM	6	AM	9	AM
			4	Cust Acct Spec	4	Cust Acct Spec
	1	Contract Analysts	6	Contract Analysts	6	Contract Analysts
	1	Leadership	4	Leadership	6	Leadership
			3	Process (CW)	4	Process (emp)
	1	Tech Standards	3	Tech Standards	4	Tech Standards
					4	Compliance/support
			3	Negotiated PPA	3	Negotiated PPA
	8	**Total Resources**	**29**	**Total Resources**	**40**	**Total Resources**
Study Resources	11	Dist. study engineers/support	31	Dist. study engineers/support	38	Dist. study engineers/support
	7	Trans. study (planners)	7	Trans. study (planners)	7	Trans. study (planners)
	18	**Total Resources**	**38**	**Total Resources**	**45**	**Total Resources**
Renewable Service Center	**11**	**Total Resources**	**20**	**Total Resources**	**25**	**Total Resources**

Notably, as shown in Figure 1, Distributed Energy Technologies increased its total number of employees and contractors from 8 at the beginning of 2015 to 40 as of November 1, 2018. Similarly, in the same period, the teams responsible for interconnection studies has also increased from 18 employees to 45, and the RSC has gone from 11 employees to 25.

Q. PLEASE ALSO HIGHLIGHT DUKE ENERGY'S RECENT TECHNOLOGY INVESTMENTS TO IMPROVE THE INTERCONNECTION PROCESS.

A. Duke Energy's Distributed Energy Technologies organization has also made significant investments in software platforms and new technology to improve efficiency and to enhance the Interconnection Customer's experience in the interconnection process. For example, the Companies have invested in the SalesForce software application to track and manage Interconnection Requests throughout the lifecycle of the interconnection process. SalesForce is used by other departments within Duke Energy to manage customer relationships and interactions, and DET has expanded its use of the capabilities in SalesForce to standardize and automate certain tasks and communications to support processing of interconnection requests. For example, DET is now leveraging the Tasks platform in SalesForce to create reminders of deliverables and milestones that will position the Companies to more efficiently deliver proactive reminders and to hold Interconnection Customers accountable for meeting their required timeframes as defined in the NC Procedures.

In addition to improving and expanding the use of the SalesForce platform, the Companies are currently developing a Customer Portal to simplify the application process, provide increased transparency into the status of projects currently in the interconnection queue, and allow customers to make payments more efficiently. The Customer Portal will be rolled out in phases, with the first phase targeting North Carolina and South Carolina large (Section 3 and Section 4) distribution generator interconnection projects. Testing and Interconnection Customers pilots will be conducted in late 2018 with full rollout currently planned in early 2019.

Q. IN YOUR VIEW, HAVE THE COMPANIES MADE REASONABLE EFFORTS TO ADMINISTER THE INTERCONNECTION PROCESS SINCE 2015?

A. Yes. The Companies are proud of the good faith improvements they have made to increase the efficiency of the interconnection process for Interconnection Customers while still ensuring a safe, reliable electrical system for all the Companies' customers. In addition to the resource investments and reorganizations described above, the Companies now assign Account Managers to be responsible for projects from the time an Interconnection Request is deemed complete until a project is operational and final true-ups are completed under the Interconnection Agreement. The Companies also voluntarily publish bi-weekly updates to queue reports on its renewables website. The Companies' Account Managers and Customer Account Specialists also make good faith efforts to proactively contact Interconnection Customers when a deadline for Interconnection Customer action is approaching to ensure they are aware of the approaching deadline. The Companies have also voluntarily offered "mitigation options" during the System Impact Study phase in order to provide Interconnection Customers with multiple feasible generator interconnection options, including options to reduce the size of the project in order to meet the Companies' technical standards and/or to "mitigate" some or potentially all Upgrade costs to support the interconnection.

The Companies' implementation of medium voltage audits and anti-islanding tests are also examples of improvements to the interconnection process because they ensure the new generators do not create unintended power quality and reliability issues for existing customers due to poor construction quality. After first implementing the audit process in 2016, the Companies also recognized the importance of completing the audits in a timely manner and engaged AE to ensure there are adequate resources to complete the audits.

The Companies have also made good faith efforts to be responsive to Interconnection Customers' business goals. For example, because many Interconnection Customers have goals to energize projects by the end of a given calendar year, both AE and the Companies have worked extended overtime hours during the year-end holiday season to accommodate as many projects as reasonably possible. These are just some of the Companies' ongoing good faith and reasonable efforts to support the generator interconnection process in North Carolina.

II. RECOVERING INTERCONNECTION-RELATED COSTS

Q. CAN YOU PROVIDE DETAILS ON THE TYPES OF COSTS THE COMPANIES INCUR TO ADMINISTER THE NORTH CAROLINA INTERCONNECTION PROCESS?

A. Yes. The Companies' expansion of the Distributed Energy Technologies and study organizations and investments in new software and technology designed to improve the interconnection process for the benefit of Interconnection Customers has resulted in a significant increase in interconnection-related costs. Most broadly, costs used to facilitate the interconnection process consist of three categories: administrative, processing, and technology costs. The Distributed Energy Technologies, RSC and distribution study organizations described in Figure 1 above are all dedicated resources that would not be required but for the requirement to process Interconnection Requests and accommodate customer- and third party developer-sponsored distributed generation assets.

In addition to the cost of the front-line dedicated interconnection resources, the Companies also incur other indirect costs associated with managing the significant growth in Interconnection Requests that are more difficult to quantify. Indirect costs include Distributed Energy Technologies growing responsibility of supporting organizations such as Technical Standards, Business Process and Governance, Strategy & Policy, Planning and Forecasting, and Reporting and Analytics.

I would also highlight a final type of indirect cost—"opportunity costs"—associated with the level of resources committed to the interconnection process. For example, while the labor cost of non-dedicated resources such as transmission planners and construction teams is recovered through direct charges or overhead allocations, those charges do not recognize the impact of diverting the resources away from other high priority work that is necessary to provide safe and reliable service to our customers.

Q. HAS THE COMMISSION PREVIOUSLY DIRECTED THE COMPANIES TO FULLY RECOVER THEIR INTERCONNECTION-RELATED COSTS FROM INTERCONNECTION CUSTOMERS?

A. Yes. The Commission has specifically directed the Companies to recover all interconnection-related costs from Interconnection Customers to the greatest extent possible. In DEC's 2016 Renewable Energy and Energy Efficiency ("REPS") Rider proceeding, the Commission specifically ordered DEC to fully utilize interconnection fees as a means of recovering interconnection costs, rather than including interconnection-related administrative and general costs in the REPS Rider, as was the Company's previous practice.[1] Subsequently, in DEP's 2017 REPS Rider case, the Commission reiterated its position that, to the "greatest extent possible," costs incurred to interconnect renewable energy generators should be recovered from the developers or Interconnection Customers through interconnection charges.[2] As a result, the Companies are proposing to increase certain fees and deposits and are allocating overhead costs to

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[1] *Order Approving REPS and REPS EMF Riders and REPS Compliance*, Docket No. E-7, Sub 1106 (Aug. 16, 2016).
[2] *Order Approving REPS and REPS EMF Riders and REPS Compliance*, Docket No. E-2, Sub 1109 (Jan. 17, 2017).

projects pursuant to the Section 4 study agreements and Interconnection Agreement to cover indirect costs, such as Salesforce and labor for resources that are not charging to specific interconnection projects.

Q. HOW ARE THE COMPANIES TRACKING AND COMPLYING WITH THE COMMISSION'S DIRECTION TO FULLY RECOVER THEIR INTERCONNECTION-RELATED COSTS FROM INTERCONNECTION CUSTOMERS?

A. On March 1, 2017, the Companies submitted their *Interconnection Cost Allocation Procedures Report* to the Commission, detailing efforts to refine their approach to tracking and assigning interconnection-related costs.[3] Consistent with the framework identified in this Report, the Companies now classify and track costs to determine needed interconnection fees by assigning labor and interconnection-related costs based upon type of activity performed to administer Interconnection Requests. The specific process outlined in the March 1, 2017 *Interconnection Cost Allocation Procedures Report* has subsequently been slightly revised to better match money received from Interconnection Customers. This revised process is designed to more easily determine if both non-refundable fees and non-direct charged administrative costs allocated to studies and construction projects are appropriate.

[3] *Interconnection Cost Allocation Procedures Report*, Docket Nos. E-100, Sub 101; E-2, Sub 1109; and E-7 Sub 1131, at 2 (Mar. 1, 2017). In the DEP REPS Order, *supra* note 2, the Commission directed DEP to work with the Public Staff in making cost allocation refinements to interconnection-related costs and to submit a report on these efforts to the Commission no later than March 1, 2017. DEP REPS Order at Ordering Paragraph 4.

Q. PLEASE ELABORATE ON THE COMPANIES' PROCEDURES TO TRACK THESE INCREASED FEES, DEPOSITS, AND OVERHEAD COSTS.

A. In compliance with the Commission's orders, the Companies have implemented a more accurate way to specifically track costs—primarily labor and technology costs—directly related to supporting interconnection-related activities. The Companies are tracking costs based on the type of work completed to best match against cash received from Interconnection Customers.

To do so, the Companies have developed three cost categories based on the type of payment received from the Interconnection Customers. These three cost categories, and the types of duties allocated to each, are summarized as follows:

Category 1, "Fees-Recovered Work:" Costs for this type of work are recovered via non-refundable fees; thus, charges in this category are generally related to Section 2 and Section 3 Interconnection Requests as well as Pre-Application processing expenses, and time spent processing and filing change of control documentation. Related technology costs to this type of processing are also included.

Category 2, "Study-Recovered Work:" Costs for this type of work are recovered through study deposits; thus charges in this category are related to Section 3 Supplemental Review and Section 4 study processes and generally applies to larger sized projects.

Specifically, costs in this category are related to processing of >2 MW state-jurisdictional Interconnection Requests and <2 MW projects requiring Supplemental Review under Section 3, answering questions and preparing agreements for Supplemental Reviews, System Impact Study agreements, Facility Study Agreements, tracking and filing correspondence, general account management, processing oversight, and related technology costs.

Category 3, "Construction Cost-Recovered Work:" Costs for this category relate to preparing Interconnection Agreements, answering customer questions, following up with customers, managing internal questions, tracking and filing correspondence, general account management, account oversight, and related technology costs. In general, the construction category includes all activities relating to the processing of Interconnection Requests after the study period has ended and up until a project is energized and connected.

Notably, none of the costs associated with regulatory support, legal expenses, small customer meter charges, dispute follow-up costs, Distributed Energy Technologies Account Management follow-up costs after energization, and normal generator follow up activity in Distribution or Transmission groups are included in these three categories or "buckets."

Q. PLEASE ELABORATE ON THE COMPANIES' REASONING TO INCREASE INTERCONNECTION-RELATED FEES AND SUPPLEMENTAL REVIEW DEPOSITS.

A. The Companies are proposing to increase the interconnection-related fees and Supplemental Review deposits because the Companies are consistently under-recovering the costs being incurred to support these transactions under the NC Procedures. In 2017, the Companies experienced an under-recovery of $1,000,635 for Category 1 types of costs and in 2018 the Companies have experienced an under-recovery of $741,529 through October 31.

This ongoing under-recovery is due to the increasing volume of Section 2 and Section 3 Interconnection Requests, coupled with the growing complexity of the Supplemental Reviews completed under Section 3 of the NC Procedures. In an effort to process more Section 3 Interconnection Requests under Supplemental Review rather than requiring full System Impact Study under Section 4, the Companies have expanded the scope of Supplemental Review to include projects requiring recloser protection devices. The increasing volumes of Interconnection Requests necessitate the Companies spending increased amount of time and monies on the actual processing of the Interconnection Requests and processing requested changes of ownership/control of the generating facility. In addition to increased interconnection-related labor expenses resulting from these volumes, the Companies have also invested in technological improvements to more efficiently manage and track the interconnection queue. To more fully recover these costs, the Companies are increasing these fees to better align with their increased costs.

Q. YOU ALSO MENTION INCREASED OVERHEADS. CAN YOU PLEASE ELABORATE ON THE INCREASED OVERHEADS THE COMPANIES ARE EXPERIENCING IN PROCESSING THE INTERCONNECTION QUEUE?

A. Yes. As mentioned previously, costs incurred to facilitate the interconnection process consists of three broad categories: administrative, processing, and technology costs. Overhead administrative costs include costs for personnel within Distributed Energy Technologies that indirectly support the interconnection process including accounting, technical standards, data management and reporting. Processing overhead costs include the RSC's costs to manage and process interconnection related calls, applications, and payments for projects not covered by fees, Distributed Energy Technologies' costs for work groups such as Account Management and Customer Operations, and the Distribution Protection and Control (aka Distributed Generation) costs incurred for responding to Supplemental Reviews and System Impact Studies. Technology costs include Salesforce enhancement project costs not related to the projects covered by fees.

Q. PLEASE PRESENT THE ADJUSTED FEES THAT THE COMPANIES HAVE INCLUDED IN THE JOINT UTILITIES REDLINE.

A.

NCIP Section	Existing Fee/Deposit	Proposed Fee/Deposit
Pre-Application Report: § 1.3.1 *Fee*	$300	$500
Interconnection Request Application Form: Attachment 2 *Fast Track Process Fee* *≥20 kW but ≤100 kW*	$250	$750
Interconnection Request Application Form: Attachment 2 *Fast Track Process Fee* *>100 kW but ≤ 2 MW*	$500	$1,000
Interconnection Request Application Form for Interconnection: Attachment 2 *Transfer of Ownership/Control Fee*	$50	$500
Interconnection Request Application Form for Interconnection: Attachment 2 *Supplemental Review Deposit* *> 20 kW but ≤ 100 kW*	$250	$750
Interconnection Request Application Form for Interconnection: Attachment 2 *Supplemental Review Deposit* *>100 kW but ≤ 2 MW*	$500	$1,000
Interconnection Request Application Form for Interconnection of a Certified Inverter-Based Generating Facility No Larger than 20 kW: Attachment 6 *Processing Fee*	$100	$200

Q. HAVE THE COMPANIES ADJUSTED ANY ASPECTS OF THE MODIFIED FEES FROM THOSE PREVIOUSLY SUPPORTED IN THE COMPANIES' MARCH 12 REPLY COMMENTS FILED WITH THE COMMISSION?

A. Yes. The Companies determined additional review of the initial fee proposal was necessary in response to stakeholder comments and updated forecasts of Interconnection Request volumes based of the recently implemented HB 589 programs. After further review, the Companies have determined that an adjustment to their prior proposal is appropriate to reduce the initial Section 2 fee from $350 to $200. This change is due to the increasing volume of Section 2 Interconnection Requests that have been experienced in 2018, as well as forecasted to continue into 2019 and beyond. Figure 2 below presents the year-over-year growth in Section 2 Interconnection Requests received from 2015 to 2018 (10 months actual and 2 months projected) as well as the number of Interconnection Requests forecasted for 2019.

Figure 2

Analysis of NC Interconnection Requests Received by IR Received Date

	2015	2016	2017	2018[1]	2019[2]
<20 kW (Section 2.0 NCIP)	1,738	960	1,408	4,016	4,362
>20 kW -100 kW (Section 3.0 NCIP)	76	13	34	151	216
>100 kW -2,000 kW (Section 3.0 NCIP)	126	41	62	37	63
Total	**1,940**	**1,014**	**1,504**	**4,204**	**4,641**
Year Over Year %age Change		**-47.7%**	**48.3%**	**179.5%**	**10.4%**

[1] From DataMart reports through 10/31/18 with estimates for November and December 2018 based on October IRs Received

[2] Forecasted amounts based on best estimates of expected Interconnection Customer behaviors

Q. ARE THE COMPANIES ADJUSTING ANY OTHER ASPECTS OF THE FEE PROPOSAL INCLUDED IN THE MARCH 12 REPLY COMMENTS?

A. No. All other Interconnection Customer processing and transactional fees are the same as the fees proposed in the Joint Utilities Redline as filed March 12, 2018.

III. <u>SIGNIFICANT INTERCONNECTION PROCESSING PROPOSALS</u>

Q. PLEASE IDENTIFY THE COMPANIES' PROPOSED MODIFICATIONS TO THE NC PROCEDURES RELATING TO PROCESSING OF INTERCONNECTION REQUESTS.

A. The Companies are proposing modifications to the NC Procedures related to enhanced scoping meetings, decision milestones during the study processes, expedited swine and poultry studies, expedited standby generator studies, and improved dispute resolution.

Q. WHY ARE THE COMPANIES PROPOSING TO MODIFY THE NC PROCEDURES TO PROVIDE "ENHANCED" SCOPING MEETINGS?

A. Initially, the Companies recommended during the stakeholder process to re-establish an optional Feasibility Study to provide Interconnection Customers greater insight on project viability prior to entering into a System Impact Study Agreement. However, based on stakeholder concerns about adding another study back to the process and potentially delaying System Impact Study, the Companies agreed to offer an enhanced Scoping Meeting providing an initial "technical review" for all Section 4 distribution-level Interconnection Customers that are not interdependent with more than one Interconnection Requests. Specifically, this technical review would function similarly to the optional Pre-Application report by informing a developer of any readily available information related to the proposed Point of Interconnection identified in the Interconnection Request, such as the likelihood of system constraints due to interconnection beyond the first zone of regulation or in areas where the project will face pre-existing voltage challenges or known transmission or distribution Upgrades.

To allow the Companies to provide Interconnection Customers with this additional information, the Companies are proposing revisions to NC Procedures Section 4.2 to extend the time between submission of an Interconnection Request and the date required to hold the scoping meeting from 10 Business Days to 30 Business Days. Additional time is necessary for the Companies to develop this additional information about the feasibility of Interconnection Customers' projects in preparation for the scoping meeting stage of the interconnection process. Ultimately, this additional information will potentially help reduce the number of speculative and likely non-viable projects occupying the Companies' interconnection resources to perform complex studies only to later elect to withdraw from the queue after receiving initial study results.

The Companies have also clarified Section 1.8.3.2 to provide projects that are interdependent with two other lower queued Interconnection Customers and designated as "on hold" the opportunity to request a scoping meeting when it becomes a Project B prior to the date the System Impact Study Agreement is due.

Q. WHY ARE THE COMPANIES PROPOSING TO ESTABLISH CLEAR DECISION AND RESPONSE TIMEFRAMES DURING THE STUDY PHASES?

A. Currently, the NC Procedures establish timeframes for utilities and Interconnection Customers to complete various steps in the interconnection process. For example, after a System Impact Study is completed and delivered to an Interconnection Customer with a Facilities Study Agreement, the Interconnection Customer must return a signed Facilities Study Agreement within 60 calendar days or the Customer's project will be deemed withdrawn.

These timeframes were established to ensure that earlier-queued Interconnection Customers continue to progress through the study process and do not unreasonably delay later-queued Interconnection Customers. This aspect of the current NC Procedures works well as Interconnection Customers move from one step of the interconnection process to the next, but the Companies' experience has been that some Interconnection Customers have refused to provide necessary information requested by the Companies or make certain essential decisions and then challenged the Companies' right to take further action due to lack of express timeframes in the NC Procedures for such cases. For example, the System Impact Study Agreement and Facilities Study Agreement each provide the Companies the right to request additional information from Interconnection Customers to complete the relevant study. However, the Companies have neither the express authority under the NC Procedures or the relevant agreement to require the Interconnection Customer to timely respond nor the right to withdraw an Interconnection Request if the customer refuses to respond to a request for information within a reasonable amount of time.

This "gap" in the NC Procedures has resulted in significant clogs in the interconnection queue in those cases where the study processes cannot move forward without the requested information. In the absence of this revision, Interconnection Customers can indefinitely delay their study, and the studies of all subsequent and interdependent projects, by refusing to provide required information or make necessary decisions. An example of the delays that can arise due to this gap is discussed later in my testimony.

Q. HAVE THERE BEEN ANY SPECIFIC DEVELOPMENTS IN THE INTERCONNECTION PROCESS SINCE 2015 THAT HAVE MADE THESE ACTION-FORCING PROVISIONS NECESSARY?

A. Yes. These action-forcing provisions are especially important given the Companies' decision to provide Interconnection Customers with "mitigation options" following implementation of the new technical standards and policies addressed by Witness Gajda, including the Circuit Stiffness Review, Line Voltage Regulators, and Method of Services Guidelines. Our efforts to accommodate Interconnection Customers by offering mitigation options within System Impact Study at different output capacities as opposed to just studying projects at the full capacity requested on the Interconnection Request inherently lengthens the study process. Establishing a required timeframe for responding to mitigation options will limit the extent of the increased study time due to the provision of mitigation options.

Q. ARE THE COMPANIES ALSO PROPOSING A REASONABLE NOTICE AND CURE OPPORTUNITY FOR INTERCONNECTION CUSTOMERS?

A. Yes. The Companies' proposal both establishes its right to request additional information or customer action and also establishes reasonable timeframes for customers to respond to such requests. Under the proposed language, if customers do not respond to a Utility's request for information within the established reasonable timeframe, the Interconnection Customer will receive a written notice of such failure with an opportunity to cure within 10 Business Days. Only after the Interconnection Customer's failure to cure within the specified cure period will DEC or DEP terminate the applicable study agreement and deem the project withdrawn.

Q. PLEASE DISCUSS THE COMPANIES' PROPOSED CHANGES TO THE NC PROCEDURES AS THEY RELATE TO PROVIDING EXPEDITED SWINE AND POULTRY STUDIES.

A. Part VII of House Bill 589 amended N.C. Gen. Stat. § 62-133.8(i)(4) to require an expedited review process for swine and poultry waste to energy projects of two (2) MW or less. In light of this mandate, the Companies worked with the Public Staff, Pork Council, North Carolina Poultry Federation, and other interested parties to develop an expedited study process that is similar to the special relief approved by the Commission in

October 2016 in Docket No. E-100, Sub 101, for certain swine and poultry Interconnection Requests in DEP's service territory. New Section 1.8.3.3 addresses how a small poultry or swine waste facility would be processed by the Utilities to meet House Bill 589's expedited study requirements. Notably, Section 1.8.3.3 allows these swine and poultry waste generators to avoid delays due to large, earlier-queued interdependent projects that may remain on hold for extended periods of time for reasons such as the lack of an action-forcing mechanism, as described above, to move the on hold project through the study process.

Q. PLEASE DISCUSS WHY THE COMPANIES ARE ALSO PROPOSING MODIFICATIONS TO THE NC PROCEDURES TO EXPEDITE THE STUDY PROCESS FOR STANDBY GENERATORS REQUESTING MOMENTARY PARALLEL OPERATION.

A. Many standby generators operate without paralleling the utility system. However, standby generators that interconnect to and have the capability to momentarily operate in parallel with the Companies' systems—generally for a period no longer than 20 seconds—are required to submit an Interconnection Request and become an Interconnection Customer of the Companies under Section 1.1.1 of NC Procedures. These momentary parallel standby generators are typically installed by commercial and industrial retail customers such as hospitals, technology companies, and other entities who have sensitive loads and must avoid any potential interruption of electricity supply. The purpose of these generators is to improve reliability, not to sell energy to the Companies.

These momentary standby generator Interconnection Customers only request to operate in parallel with the grid during the time their load is transitioning back to the utility system after a test or outage. As a result, these standby generator Interconnection Requests require more limited study to ensure they comply with technical requirements and have proper protection and control equipment to allow for safe parallel operation of the generator. Generally speaking, these generators do not undergo as robust of a System Impact Study analysis as "full power export" Interconnection Customers that sell their output to the Companies because standby generators are designed and operated as zero export generation, are not interdependent, and, accordingly, have no adverse effect on other Interconnection Customers' queue position.

The Companies also receive very few Interconnection Requests for standby generators (three in 2017 and nine to date in 2018). Due to the relatively few requests for momentary standby generator interconnections and the fact that these Interconnection Requests do not require a significant amount of study time, evaluating them on an expedited basis apart from the traditional queue is reasonable and will benefit the Companies' commercial and industrial retail customers seeking to install this type of generator at their facilities. The proposed addition of Section 1.8.3.4 achieves these objectives.

IV. DISPUTE RESOLUTION PROVISIONS

Q PLEASE PROVIDE THE COMPANIES' PERSPECTIVE ON THE SECTION 6.2 DISPUTE RESOLUTION PROCESS UNDER THE NC PROCEDURES.

A. Section 6.2 of the NC Procedures establishes a multi-step process for resolving disputes between Interconnection Customers and the Utilities administering the interconnection process. The first step contemplates that the initiating party (normally the Interconnection Customer) must provide the other party (normally the Utility) with written notice describing the nature of the dispute. The responding party then has 10 business days to respond, with the parties normally scheduling a conference call or meeting to attempt to resolve the dispute. If the dispute has not been resolved within 10 business days, the NC Procedures provide that either party may contact the Public Staff for assistance in informally resolving the dispute. If the parties are still unable to informally resolve the dispute, either party may file a formal complaint with the Commission.

The Companies' experience since the Commission last approved the NC Procedures in 2015 is that the current dispute resolution process has worked well in most cases and the vast majority of disputes have been successfully resolved through the informal "first step" of the process without involvement by the Public Staff or the Commission. However, the number and complexity of Interconnection Customer-initiated disputes has steadily increased since 2015, which has required the Companies as well as the Public Staff to commit significantly more time and resources towards resolving interconnection disputes. As discussed in more detail by Duke Energy Witnesses Freeman and Gajda, the continued growth of generating facilities interconnecting to the Companies' distribution systems have increasingly required more significant, and costly, Upgrades to the Companies' systems and have begun to push the boundaries of the level of generation that can be safely and reliably interconnected consistent with Good Utility Practice. As a result, Interconnection Customers are increasingly being required to choose between "higher cost or reduced capacity" which has resulted in an increasing number of disputes where the Interconnection Customer and/or the Companies have ultimately requested the Public Staff's assistance to informally resolve the dispute under the NC Procedures. The Public Staff's involvement, technical understanding, and perspective has always been very valuable in this process, and, in nearly all instances, has enabled the Companies and Interconnection Customers to successfully resolve the dispute.

Q BASED UPON RECENT EXPERIENCE OVER THE PAST FEW YEARS, DO THE COMPANIES HAVE ANY SPECIFIC CONCERNS WITH THE CURRENT DISPUTE RESOLUTION PROCESS?

A. Yes. Similar to the delay concerns described above arising due to the lack of express timeframes for Interconnection Customers to provide requested information and make necessary decisions, the Companies are also concerned with the potential ambiguity of the NC Procedures as it relates to the obligation of the Interconnection Customer to pursue the express remedies for dispute resolution under Section 6.2. As currently drafted, Section 6.2 of the NC Procedures states that "any disputed loss of Queue Number shall not be final until Interconnection Customer abandons the process set out in this section or a final Commission order is entered." The Companies' view has been that once a dispute has been initiated by an Interconnection Customer under Section 6.2, the failure of such customer to pursue the express remedies available within a reasonable timeframe constitutes "abandonment of the process." However, developers have asserted that it is solely up to the Interconnection Customer to determine when it has "abandoned the process," which leads to the absurd conclusion that an Interconnection Customer could remain in dispute in perpetuity with no recourse for the Companies or interdependent Interconnection Customers awaiting a decision by the dispute-initiating Interconnection Customer regarding whether to proceed or withdraw. This "open-ended delay" scenario is certainly not the result intended by the Commission under Section 6.2.

Q HOW HAVE THE COMPANIES PROPOSED TO ADDRESS THE DELAY SCENARIO CREATED BY THE AMBIGUITY IN THE DISPUTE RESOLUTION SECTION?

A. The Companies are proposing revisions to Section 6.2 of the NC Procedures to establish clear timeframes for both parties to diligently pursue the dispute resolution process. Similar to the timeframes discussed above, failure of the initiating party to timely pursue the available express remedies will result in withdrawal from the queue. These proposed changes are addressed in the Companies' Redline to the NC Procedures sponsored by Duke Energy Witness Gajda.

Q. CAN YOU PROVIDE AN EXAMPLE ILLUSTRATING THE NEED TO IMPOSE MORE EXPRESS TIMEFRAMES BOTH DURING THE STUDY PROCESS AND IN CONNECTION WITH THE DISPUTE RESOLUTION PROCESS?

A. One recent case illustrates the challenges the Companies are experiencing. In this particular case, the Interconnection Customer took approximately one year from the date on which the mitigation options were provided until the Interconnection Customer elected to move forward with Facilities Study.

During this one-year process, the Interconnection Customer challenged the Companies' technical conclusions through numerous rounds of questions. DEP personnel participated in several meetings and conference calls to address the questions. The Interconnection Customer refused to select a mitigation option for approximately six months and then elected to file a notice of dispute under Section 6.2. DEP responded to the notice of dispute and then, at the request of the Interconnection Customer, participated in a meeting facilitated by the Public Staff. After meeting with the Public Staff, the Interconnection Customer continued to challenge the

Companies' technical conclusions and continued to refuse to select a mitigation option. After this extensive process proved unsuccessful to resolve the dispute and because no express timeframes are specified for responding to mitigation options or pursuing the dispute resolution process under Section 6.2, DEP issued the System Impact Study to the Interconnection Customer based on the full requested capacity in the Interconnection Request of the proposed generating facility. At the very end of the 60-day allotted time period for executing the Facilities Study Agreement, the Interconnection Customer sent additional questions but then ultimately signed the Facilities Study Agreement.

In summary, due to the lack of express timeframes for responding to mitigation options and pursuing the Section 6.2 dispute resolution process, over 12 months passed from the date DEP provided mitigation options to the Interconnection Customer until the project moved into Facilities Study. During that year, substantial amounts of DEP resources were dedicated to this process—resources that would otherwise have been devoted to the study process for other projects. Even more significantly, there are numerous interdependent Interconnection Customers subordinate to this project on a particular substation and all such projects are required under the NC Procedures to remain on hold while the dispute resolution process continued. The Public Staff also committed significant time and effort to assist in informally resolving the dispute. This example highlights the need for the Company to be able to impose reasonable timeframes for providing information and making necessary decisions and for eliminating any ambiguity in Section 6.2 as it relates to the obligation of the initiating party to pursue the available remedies.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(WHEREUPON, Rebuttal Exhibits JWR-1, JWR-2, JWR-3, Corrected Rebuttal Exhibit JWR-4 and Rebuttal Exhibit JWR-5 are marked for identification as prefiled. Corrected Rebuttal Exhibit JWR-4, pages 11 and 12, contain confidential information, and is filed under seal.)

(WHEREUPON, the prefiled rebuttal testimony of JEFFREY W. RIGGINS is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**REBUTTAL TESTIMONY OF**
Petition for Approval of Generator	)	**JEFFREY W. RIGGINS**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Jeffrey W. Riggins, P.E., Director of Standard Power Purchase Agreements ("PPAs") and Generator Interconnections for Duke Energy Corporation ("Duke Energy"). My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies").

Q. ARE YOU THE SAME JEFFREY W. RIGGINS WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain issues raised by the Public Staff and intervenors in their respective direct testimony pertaining to the North Carolina Interconnection Procedures ("NC Procedures"). Specifically, I will address issues raised in the testimonies of Public Staff witness Jay Lucas, Interstate Renewable Energy Council ("IREC") witness Sara Auck, and North Carolina Clean Energy Business Association ("NCCEBA") witness Christopher Norqual. My rebuttal testimony responds to and largely supports the Public Staff's recommendations regarding adding additional timeframes for utility and

Interconnection Customer action in certain sections of the NC Procedures, while opposing IREC's advocacy for the Commission to impose a "timeline enforcement mechanism" on the Companies and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" and, together with the Companies, the "Utilities"). I also explain why the Companies support Public Staff's recommended additions to current queue reporting as reasonable, but oppose much of IREC's queue reporting proposals, which the Companies believe are unduly burdensome. I also respond to the Public Staff's and IREC's comments on Hosting Capacity Maps, and show that deploying a distribution system-focused HCM would likely have limited benefits to most North Carolina small Section 2 generator Interconnection Customers and would also be prohibitively expensive if the cost is fully assigned to Interconnection Customers, as recommended by the Public Staff. I also provide additional support for the Companies' proposed revisions to certain interconnection fee revisions within the NC Procedures and further address the Companies' position on the NC Procedures Section 6.2 dispute resolution process. I also address the Companies' position regarding acceptability of surety bonds as Financial Security for Interconnection Facilities. Finally, I briefly address the Public Staff's and other parties' support for proposed modifications to expedite processing of swine and poultry Interconnection Requests as well as standby generator Interconnection Requests.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am submitting five exhibits. Rebuttal Exhibit JWR-1 provides DEC's and DEP's most current distribution queue status report as of December 27, 2018, along with the FAQs and status definitions the Companies have posted to the Companies' renewables website. Rebuttal Exhibit JWR-2 provides an example of the free "Pre-Request Response" and "Pre-Application Report" the Companies provide to Interconnection Customers. Rebuttal Exhibit JWR-3 provides support for the Companies' revisions to the North Carolina interconnection fees. Rebuttal Exhibit JWR-4 provides the Commission certain data request responses referenced in my testimony. Last, I am submitting Rebuttal Exhibit JWR-5, which provides a form surety bond determined acceptable by the Companies' credit and risk management department. I am also co-sponsoring Rebuttal Exhibit JWG-1, which is the Companies' updated redline of the North Carolina Interconnection Procedures ("NC Procedures").

I. Utility and Interconnection Customer Response Timeframe Requirements

Q. PLEASE ADDRESS THE PUBLIC STAFF'S RECOMMENDATIONS RELATED TO UTILITY AND INTERCONNECTION CUSTOMER RESPONSE TIMEFRAME REQUIREMENTS UNDER THE NC PROCEDURES.

A. The Public Staff recommends adding more clearly defined response timelines within four sections of the NC Procedures relating to activities such as providing existing information through the Pre-Application Reports, scheduling scoping meetings, and processing refunds where an Interconnection Customer withdraws from the interconnection queue. Specifically, Public Staff witness Lucas states that the Public Staff supports incorporating the following timeframes into the NC Procedures:

- a 10 Business Day requirement in Section 1.3.3 for Utilities to provide a pre-application report;
- a 10 Business Day requirement in Section 2.2.2 for Utilities to provide reasons for failure of fast track screens;
- a 60 Business Day requirement in Section 6.3.3 for Utilities to settle up interconnection study deposits; and,
- maintaining the 10 Business Day requirement to schedule a scoping meeting in 4.2.1.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS LUCAS' RECOMMENDATIONS REGARDING ESTABLISHING MORE CLEAR TIMEFRAMES FOR TAKING ACTION?

A. The Companies generally agree with the Public Staff and other parties that setting clear and reasonably-achievable timeframes for action within the NC Procedures promotes transparency and is appropriate for both Utilities and Interconnection Customers to timely complete routine activities, such as providing existing information, scheduling meetings, and making payments or providing refunds. In processing Interconnection Requests, the

Companies make reasonable efforts as required by NC Procedures Section 6.1 to meet all timeframes; although, as discussed in my direct testimony and the testimony of DEC/DEP witness Freeman, certain timeframes have been challenging to meet due to the increasing complexity of processing North Carolina's unparalleled volume of utility-scale solar Interconnection Requests, as well as the fact that many aspects of the study process are outside of the Companies' control.[1] However, the Companies agree that establishing reasonable timeframes is beneficial to the overall administration of the interconnection process.

In response to Public Staff witness Lucas' specific recommendations, the Companies agree with several of the proposed modifications, but have determined that other proposals either conflict with existing provisions of the NC Procedures or are not needed as the same timeframe is already more clearly addressed in another Section of the NC Procedures. For example, the Public Staff's proposed addition of "within ten (10) business days" to Section 1.3.3 to set the timeframe by which the utility must produce the Pre-Application Report is not needed as this same 10 Business Day timeframe is already more precisely addressed in Section 1.3.1. Section 1.3.1 (as modified by the Companies' proposed NC Procedures revisions) provides: "The Utility shall provide the Pre-Application data described in Section 1.3.2 to the Interconnection Customer

[1] DEC/DEP Riggins Direct Testimony, at 6-7; DEC/DEP Freeman Rebuttal Testimony, at 7-9.

within ten (10) Business Days of receipt of the completed request form and payment of the $500~~$300~~ fee." The current Section 1.3.1 establishes "receipt of a completed request form" as the starting point for tracking the 10 Business Day timeframe. In contrast, the Public Staff's proposed addition to Section 1.3.3 does not include a clearly defined starting point and may cause confusion to the extent that it could be read to conflict with or modify the timeframe in Section 1.3.1.

The proposed addition of "within ten (10) business days" to Section 2.2.2 also conflicts with existing language of Section 2.2.1, which provides the Utility 15 Business Days to complete the initial small generator interconnection screening process. The vast majority of the Section 2 (20 kW or less inverter-based generating facilities) are residential or small commercial net-energy metering ("NEM") program customers and very rarely do the Companies determine that the Section 2 NEM generating facilities cannot be interconnected. When such circumstances arise, the Companies would follow existing Sections 2.2.1 and 2.2.2 to advise the Interconnection Customer within 15 Business Days of processing a completed Section 2 Interconnection Request and to explain why the proposed generating facility failed the initial Fast Track screening and must proceed either to Section 3.4 Supplemental Review (*see* 2.2.2.1) or to the full Section 4 Study Process (*see* 2.2.2.2).

Q. DO THE COMPANIES SUPPORT THE PUBLIC STAFF'S PROPOSED 60-BUSINESS DAY TIMEFRAME TO PROVIDE A FINAL ACCOUNTING REPORT TO A WITHDRAWN INTERCONNECTION REQUEST?

A. Yes. As Public Staff witness Lucas recognizes, the Companies often engage consultants and independent contractors to support the interconnection study process and significant time may be required for the Companies to receive and process contractor invoices before settling up interconnection deposits after any voluntary or deemed Interconnection Request withdrawal.[2] The Companies support the Public Staff's proposed 60 Business Day timeframe recommendation to settle interconnection deposits pursuant to Section 6.3.3. Notably, 60 Business Days is shorter than the 90 Business Days originally proposed by the Utilities in the prior comment proceeding. To the extent that additional time is required to complete the final accounting for a specific Interconnection Customer (such as a large and complex transmission-connected generator), the utility would adhere to the requirements of Section 6.1 to provide the Interconnection Customer an explanation of why the additional time is needed and the expected date by which the utility can deliver the final accounting. To the extent that the final accounting can be completed in less than 60 Business Days, such as where the Interconnection Customer withdraws early in the interconnection

[2] Public Staff Lucas Direct Testimony, at 29-30.

process, the Companies will issue the final accounting more expeditiously as it becomes available.

The Companies also support retaining the existing 30 calendar days from the date of issuance of the final accounting report for either the utility to make any refund required by the final accounting or for the Interconnection Customer to make any supplemental payment for the study work completed if the Interconnection Customer's cost responsibility exceeds its previous aggregate deposit payments, as described in Section 6.3.3.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION REGARDING THE TIMING OF SECTION 4.2.1 SCOPING MEETINGS.

A. Public Staff witness Lucas recommends retaining the pre-existing ten (10) Business Day requirement in Section 4.2.1 to schedule a scoping meeting with Interconnection Customers. The Companies agree to the Public Staff's recommendation to retain the 10 Business Day requirement in Section 4.2.1, but note that preparing a more detailed "technical review," as described in my direct testimony will require additional time beyond 10 Business Days.[3] The Companies continue to believe this more robust scoping meeting could benefit Interconnection Customers by providing more detailed information regarding the feasibility of the proposed generator interconnection earlier in

[3] DEC/DEP Riggins Direct Testimony, at 25-26.

the interconnection process. Providing more detailed information earlier could also potentially help reduce the number of speculative and likely non-viable projects occupying the Companies' interconnection resources to perform complex studies only to later elect to withdraw from the queue after receiving initial study results. The Companies also believe that this enhanced scoping meeting approach can still be offered and scheduled, at the Interconnection Customer's option, "as mutually agreed to by the Parties" under Section 4.2.1. After filing direct testimony, the Public Staff indicated their support for this optional approach where the Interconnection Customer agrees to a delay in scheduling the scoping meeting to enable the Companies to prepare for an enhanced technical review.[4]

II. Timeline Enforcement Mechanism

Q. DID INTERVENORS RAISE CONCERNS RELATED TO CURRENT INTERCONNECTION PROCESSING TIMEFRAMES?

A. Yes. NCCEBA witness Norqual argues that interconnection delays have negatively impacted Cypress Creek Renewables' ("CCR") business.[5] IREC witness Auck also raises concerns with delays in processing Interconnection Requests.[6]

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[4] Rebuttal Exhibit JWR-4, Public Staff's response to the Companies' Data Request 2-3.
[5] NCCEBA Norqual Direct Testimony, at 5-8.
[6] IREC Auck Direct Testimony, at 43-45.

Q. IREC RECOMMENDS THE COMMISSION ADOPT A TIMELINE ENFORCEMENT MECHANISM ("TEM") AS A SOLUTION TO REDUCE RECENTLY-EXPERIENCED DELAYS PROCESSING INTERCONNECTION REQUESTS. DO YOU AGREE WITH IREC'S PROPOSAL?

A. No. The Companies oppose adoption of a TEM and believe such a punitive measure is not appropriate in light of the Companies' continuing good faith and reasonable efforts to process North Carolina's unprecedented volume of utility-scale solar generator Interconnection Requests as well as the complexities of North Carolina's interconnection process, as discussed by DEC/DEP witness Freeman.

First, as stated in my direct testimony, the Companies have made significant investments in staffing, technology, and process improvements to address the delays identified by NCCEBA and IREC.[7] Further, as explained by DEC/DEP witness Freeman, the unprecedented and unparalleled number of utility-scale solar generators already interconnected by DEC and DEP validates these reasonable and good faith efforts.[8] I also explain in my direct testimony the Companies' significant efforts to staff up in order to more efficiently administer the interconnection process and to conduct studies for projects that are ready to be studied, i.e. Project A or

[7] DEC/DEP Riggins Direct Testimony, at 10-14.
[8] DEC/DEP Freeman Direct Testimony, at 7-12.

Project B Interconnection Requests.[9] Secondarily, as DEC/DEP witness Freeman discusses in his rebuttal testimony, IREC's recommendation is based on a flawed assumption that the Companies have complete control over the amount of time it takes to interconnect a project.

Q. DOES IREC'S PROPOSAL EVEN ATTEMPT TO TAKE INTO ACCOUNT THE UNIQUE COMPLEXITIES OF THE NORTH CAROLINA INTERCONNECTION LANDSCAPE OR RECOGNIZE OTHER FACTORS OUTSIDE OF THE COMPANIES' CONTROL THAT SUBSTANTIALLY LENGTHEN INTERCONNECTION PROCESSING TIME PERIODS?

A. No. The TEM described by IREC witness Auck would simply "calculate[] the total aggregate average time, in business days, that it has taken to interconnect projects…starting from the date an application is received until the date an interconnection service agreement is executed" and then penalize the Companies if they fail to meet the target on an average basis in a given year.

Such an approach absurdly assumes that the length of time from Interconnection Request submission to Interconnection Agreement ("IA") execution is completely within the Companies' control. That assumption is baseless and demonstrates a profound lack of understanding of the complexity of the interconnection process in North Carolina.

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[9] DEC/DEP Riggins Direct Testimony, at 8-10.

To the contrary, DEC/DEP witness Freeman extensively describes in his rebuttal testimony the many factors affecting interconnection timelines in North Carolina that are outside of the Companies' control. One of the major factors leading to the long interconnection periods is the concept of interdependency established in Section 1.8 of the NC Procedures. Pursuant to this Commission-approved queueing process, the Companies prioritize study of Interconnection Customers whose interconnection is not impacted by other earlier-queued Interconnection Requests. Projects that are impacted by or "behind" two or more other Interconnection Requests are designated as "on hold" until earlier queued Interconnection Customers elect either to sign an IA and fund generator interconnection System Upgrades or to withdraw (*see* 1.8.3).

In many instances, numerous projects have sought interconnection to the same distribution circuit or substation, resulting in numerous projects being placed "on hold' in accordance with the NC Procedures. Under IREC's simplistic TEM proposal, the Companies could be penalized for the delays experienced by such projects even though the Companies are actually adhering to the terms of the NC Procedures.

Witness Freeman also describes the many aspects of the System Impact Study process that are outside of the Companies' control. For instance, Interconnection Customers often request multiple extensions at various stages of the interconnection process and such extensions substantially lengthen the interconnection timeline not only for the specific project requesting the extension, but also for other projects interdependent on such project. Under IREC's TEM proposal, all such extensions (along with cure periods, formal and informal disputes, failures of developers to provide correct information, delays in developer obtaining rights of way, developer requests for information) would, unjustly, lead to penalties for the Companies.

In fact, IREC's simplistic TEM proposal would actually create an incentive for the Companies to refuse to grant extensions or cure periods or allow even the slightest accommodation for Interconnection Customers. Based on the Companies' experience, any such approach would be untenable and would simply result in endless disputes with Interconnection Customers.

Q. IS IREC'S RECOMMENDED TEM REASONABLE?

No. IREC's TEM proposal completely fails to take into account the complexity of the interconnection process in North Carolina and will accomplish absolutely nothing with respect to resolving the primary drivers of the Companies' current interconnection processing challenges that DEC/DEP witness Freeman discusses in greater detail. In light of the Companies' good faith efforts and unparalleled success interconnecting utility-scale solar projects, as well as the current complexities of the interconnection process in North Carolina, imposition of a TEM would be inappropriate, unjust, and unreasonable.

Further, the Companies question the appropriateness of IREC's proposal to impose financial penalties through "positive and negative earnings adjustment" for deviations from the timeframes set forth in the NC Procedures.[10] While I am not an attorney, IREC's proposed earning adjustment mechanism appears inconsistent with North Carolina's general ratemaking framework under the Public Utilities Act under which the Commission fixes the Companies' rates until the next general rate case.

Q. DOES THE PUBLIC STAFF SUPPORT ADOPTION OF A TEM IN NORTH CAROLINA?

A. No. Public Staff witness Lucas makes clear that the Public Staff does not support adoption of a TEM. Witness Lucas testifies that "the Utilities appear to have made good faith efforts to interconnect DG" and that the "unprecedented growth of solar could only have been brought about by cooperation of the Utilities."[11]

Q. DO OTHER STATES UTILIZE A TEM IN THEIR INTERCONNECTION PROCESS?

A. Massachusetts and New York appear to be the only states to have adopted a TEM, and establishment of these TEMs were required by enabling legislation enacted in these States.[12]

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[10] IREC Auck Direct Testimony, at 44.
[11] Public Staff Lucas Direct Testimony, at 32.
[12] Rebuttal Exhibit JWR-4, IREC's response to the Companies' Data Request 1-20.

III. <u>Communication, Reporting, and Transparency</u>

Q. IN YOUR DIRECT TESTIMONY, YOU EXPLAINED THE COMPANIES' EFFORTS TO IMPROVE REPORTING AND COMMUNICATION RELATED TO THE INTERCONNECTION PROCESS. PLEASE SUMMARIZE THOSE EFFORTS.

A. The Companies have added additional resources and made significant investments in new technology systems—primarily Salesforce—to better track the status of each Interconnection Request throughout the interconnection process. The Companies also voluntarily publish detailed bi-weekly DEC and DEP distribution system "Queue Snapshot" reports on its website identifying the interdependency status, operational or study status, project capacity and fuel source, as well as distribution feeder and substation name for each Interconnection Requests above 20 kW. This information is available on the Companies' website at <u>https://www.duke-energy.com/business/products/renewables/generate-your-own/interconnection-queue</u>. My Rebuttal Exhibit JWR-1 provides DEP's and DEC's most current distribution queue status report as of December 27, 2018, along with FAQs and status definitions that the Companies have posted to the website.

To support more efficient customer communications and reporting, the Companies are also currently expanding the use of features within Salesforce to create reminders of the Companies' milestones and developer's milestones so approaching deadlines can be proactively monitored and addressed. The Companies have also added Account Managers and Customer Account Specialists that are dedicated to managing projects and addressing inquiries from Interconnection Customers to ensure that the interconnection process moves as efficiently as reasonably possible.

Q. HAVE THE COMPANIES MADE ANY CHANGES WITH RESPECT TO PUBLISHING THEIR INTERCONNECTION QUEUES SINCE THE COMMISSION LAST APPROVED THE NC PROCEDURES IN 2015?

A. Yes. In the Commission's May 2015 Order approving the current NC Procedures, the Commission directed the Companies to file quarterly queue status and queue performance reports with the Commission in Docket No. E-100, Sub 101A. As noted above, and as commended by the Public Staff, the Companies voluntarily publish an updated Queue Snapshot report twice monthly (bi-weekly) to improve transparency into the interconnection study process and to assist Interconnection Customers in keeping informed of the status of their projects. Notably, the Companies' current voluntary queue tracking and reporting seems to already provide more information than most utilities in other states, as IREC was only able to identify a few states that are required to *or* voluntarily provide interconnection queue reporting of large generator interconnections.[13]

[13] Rebuttal Exhibit JWR-4, IREC's response the Companies' Data Request 1-18.

Looking ahead, in early 2019, the Companies plan to further enhance their published Queue Snapshot reports by providing additional granularity on the progress of System Impact Studies, which have grown in complexity since the current NC Procedures were approved in 2015. For example, the Companies recently began publishing Engineering Administrative Designations ("EAD") in their queue reports. Identifying the current EAD, such as "Voltage Flicker Mitigation Options" review, helps to provide Interconnection Customers a better understanding of which phases of the System Impacts Study process have been completed and the phases that are still underway. Rebuttal Exhibit JWR-1 shows the information currently provided in these queue reports.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S RECOMMENDATIONS WITH RESPECT TO QUEUE REPORTING AND COMMUNICATION BETWEEN THE COMPANIES AND INTERCONNECTION CUSTOMERS THROUGHOUT THE INTERCONNECTION PROCESS.

A. Public Staff witness Lucas recognizes the Companies' efforts to communicate throughout the interconnection process and the significant improvements in the availability of information being provided to customers.[14] Public Staff witness Lucas also recommends that the Utilities evaluate and provide a detailed cost estimate of the cost of developing and

[14] Public Staff Lucas Direct Testimony, at 18.

operating an online portal to allow developers to track near real time status (within 2 Business Days of changes) of projects.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S RECOMMENDATIONS?

A. Yes. The Companies are already developing an online Interconnection Customer portal, which will allow Interconnection Customers to electronically submit Interconnection Requests and payments and will allow the Companies to share status information with Interconnection Customers. This Customer portal will pull information in "real time" from Salesforce and will be accessible to the Interconnection Customer upon logging into its Customer portal page. The Companies commit to share with the Public Staff the current plans for the online portal and to identify additional features that need to be evaluated.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATIONS WITH RESPECT TO THE ANNUAL QUEUE REPORTING TO THE COMMISSION.

A. Public Staff witness Lucas recommends modification of the generator interconnection reports filed with the Commission in Docket No. E-100, Sub 113B from annually to quarterly, and also recommends the reports include operational status and identify all FERC-jurisdictional projects.

Due to the significant increase in the number of generator interconnections since the Commission established this reporting requirement, the Companies are not opposed to increasing the frequency of reporting this information to the Commission from annually to quarterly and adding the operational status and FERC projects. The Companies already file quarterly Queue Status and Interconnection Request Performance Reports with the Commission in Docket No. E-100, Sub 101A, and the Companies are not opposed to making a quarterly filing identifying interconnected generators as requested by the Public Staff. This report will identify all projects above 20 kW requesting interconnection and their operational status as is currently posted to the Companies' website in the most recently published biweekly Queue Snapshot. For administrative efficiency, the Companies recommend adding the Public Staff's requested installed generator reporting information into the quarterly report filing currently made in Docket No. E-100, Sub 101A and separately continuing to file the small generator report annually in Docket No. E-100, Sub 113B.

Q. PLEASE RESPOND TO IREC'S REQUEST FOR ADDITIONAL INFORMATION TO BE INCLUDED IN QUARTERLY REPORTS.

A. IREC witness Auck recommends the Utilities continue filing quarterly performance reports, but advocates for adding significant additional granularity and reporting requirements to the current information required by the Commission. As noted, the Companies already file, and will continue filing, Queue Status and Interconnection Request Performance Reports with the Commission identifying the following intervals for all Section 4 Interconnect Requests: (i) Queue Assignment to Issuance of Interconnection Agreement; (ii) Interconnection Agreement Receipt to

Project Completion; (iii) Queue Assignment to Project Completion; and (iv) Projects interconnected by year.

While the Company supports continuing the current queue performance reporting to show the Commission progress and trends in the interconnection process, the administrative burdens and expense of expanding the quarterly performance reporting to include the voluminous and granular data in IREC witness Auck's Exhibit SBA-Direct-4 will significantly outweigh any benefit to Interconnection Customers or the overall interconnection process in North Carolina. In order to provide the granular information requested by IREC, such as maximum, mean, and median processing times for multiple steps in the study process as well as project-by-project Fast Track and supplemental review statistics, the Companies would need to dedicate additional engineering and administrative resources focused on reporting and developing metrics versus actually studying Interconnection Requests. This increase in reporting seems particularly unreasonable as it would add to the Companies' already-under-recovered costs of administering the interconnection process, which IREC is already challenging. Moreover, as described above and by DEC/DEP witness Freeman, details such as the maximum, mean, and median processing times would be inadequate without adding dozens of other burdensome reporting requirements such as tracking interdependencies and delays arising due to circumstances outside the Companies' control.

Additionally, the recommendation to provide real-time cost details for each project would require significant investment in the Companies' financial systems. As required by the NC Procedures, the Companies complete a financial review and provide a final accounting report after invoices are processed and costs are available. For the small projects that are the primary focus of IREC's testimony, costs should not be a concern since most of the Companies' costs are covered by fees rather than deposits.

Q. PLEASE RESPOND TO IREC'S REQUEST WITH RESPECT TO MONTHLY DISTRIBUTION QUEUE REPORTING.

A. IREC witness Auck also advocates that the Companies be required to publish a detailed Distribution System Interconnection Queue report on their websites "on at least a monthly basis" in a sortable spreadsheet format.[15] IREC's Exhibit SBA-Direct-3 proposes that the distribution queue report include 23 separate data fields.

As described above, DEC and DEP each already voluntarily publish public Queue Snapshot reports on its website in a downloadable format and update it twice a month; more frequently than IREC requests. Much of the data recommended in witness Auck's Exhibit SBA-Direct-3 is included in the existing queue report. Some of the information requested, however, is currently included in individual notifications to Interconnection Customers as milestones are achieved throughout the interconnection process and the

[15] IREC Auck Direct Testimony, at Exhibit SBA-Direct-3.

Companies disagree with IREC's recommendation to publicly publish this information. Specifically, detailed Interconnection Customer cost and the dates that the IA and other agreements are executed would be inappropriate to share publicly in a queue report.

Q. WHAT SPECIFIC CONCERNS WOULD THE COMPANIES HAVE WITH IMPLEMENTING IREC'S RECOMMENDATION?

A. Some of the data elements IREC witness Auck listed in Exhibit SBA-Direct-3 are already provided in the biweekly Queue Snapshot reports voluntarily published on the Companies' website. The data currently provided allows Interconnection Customers to determine the interdependency status and operational status of their Interconnection Request and to determine where their request is in queue relative to other Interconnection Requests. However, much of the information in Exhibit SBA-Direct-3, including the date, cost, and transformer data, is appropriately communicated directly to each Interconnection Customer through Pre-Request Responses, Pre-Application Reports, and emails/reports as projects proceed through the interconnection process and should not be published in the monthly queue reports. The Companies' Salesforce application currently captures the effective dates of agreements and the start and end dates of the various study and construction milestones, but does not capture the date of notifications or whether projects pass/fail screens. IREC's proposed reporting on notification dates and screen results would require additional investments to enhance the Salesforce database and significant manual effort to populate the fields after reviewing the email communications already provided to Interconnections Customers, adding additional costs to the interconnection process.

Further, IREC witness Auck seems to recommend that the Companies should be required to include small <20 kW NEM projects in its distribution system queue. The Companies already include Section 3 and Section 4 NEM projects in their Queue Snapshot reports as those projects are required to proceed through Fast Track, Supplemental, or the Section 4 Full Study process. The Companies do not, however, include the thousands of Section 2 (<20kw) projects because those requests are managed in the PowerClerk system and to date have not been subject to the Fast Track screens based on the Companies' determination that the Section 2 projects can currently interconnect safely and reliably at lower levels of penetration. These Section 2 NEM projects have historically been processed very efficiently and the administrative burden and cost associated with including them in queue reporting is unjustified.

IV. <u>Hosting Capacity Maps</u>

Q. PLEASE ADDRESS THE PUBLIC STAFF'S AND INTERVENORS' POSITIONS REGARDING HOSTING CAPACITY MAPS.

A. Public Staff witness Lucas states that a distribution level hosting capacity map ("HCM") would provide little benefit due to the shift towards larger, transmission-connected projects in North Carolina.[16] Public Staff witness Lucas' recommendation is to build on the grid location guidance provided for CPRE tranche 1 to "provide basic information on the transmission system and identify those areas that are at or near their hosting capacity."[17] Witness Lucas also recommends that the Companies provide the Commission and the Public Staff a detailed estimate of the cost to develop and maintain an HCM utilizing existing data and tools. The Public Staff also notes that all costs associated with HCMs should be recovered from distributed generation ("DG") developers through fees and charges.

I agree with the Public Staff that there has been a shift in Qualifying Facilities ("QF") submitting Interconnection Requests in North Carolina from distribution-connected to transmission-connected generating facilities. During calendar year 2018, the Companies received 44 new transmission-connected solar Interconnection Requests compared with just 16 distribution-connected solar Interconnection Requests greater than or equal to one MW (excluding NEM) in North Carolina. The Companies also annually receive Interconnection Requests for thousands of customer-sited net metering projects but these projects cannot change their proposed location in response to information provided through an HCM. Therefore, it appears that there would be a limited audience for a distribution level HCM in North Carolina.

[16] Public Staff Lucas Direct Testimony, at 23.
[17] Public Staff Lucas Direct Testimony, at 23.

Also, I agree that it would be in the best interest of both the Companies and the DG developers for the Companies to continue to refine the transmission grid locational guidance required by CPRE. However, input from stakeholders and additional details from the Commission and the Public Staff on the scope of any proposed changes to the grid locational guidance will be needed before a detailed estimate of the costs for such work could be developed.

Q. WHAT IS THE COMPANIES' POSITION ON IREC'S RECOMMENDATION THAT THE COMMISSION ORDER THE UTILITIES TO DEVELOP HCMs?

A. IREC witness Auck recommends that the Utilities be required to each implement a hosting capacity analysis based on proposals developed by a Commission-initiated working group. She testifies that the "ideal hosting capacity maps would include detailed hosting capacity for each node, along with substation, circuit and feeder information"[18] suggesting that "[w]ithout a hosting capacity map, customers have no information regarding the best and worst locations for new DER."[19]

I do not agree with IREC witness Auck's assertion that an HCM is the only way for customers to evaluate locations for new distributed energy resources ("DER"). As required in the NC Procedures, the Companies offer potential Interconnection Customers both a free "Pre-Request Response"

[18] IREC Auck Direct Testimony, at 38.
[19] IREC Auck Direct Testimony, at 35.

(1.2) and a more detailed "Pre-Application Report" (1.3) (examples of both are provided as Rebuttal Exhibit JWR-2). In addition, the Companies publicly post their respective interconnection queues through the biweekly Queue Snapshot reports as well as transmission grid locational guidance to inform developers of utility-scale DER regarding the number, proposed size, and general location of constrained areas on the Companies' transmission systems. Utilizing these existing resources, an Interconnection Customer can preliminarily determine the feasibility of a project before submitting an Interconnection Request.

Q. PLEASE RESPOND TO IREC WITNESS AUCK'S ASSERTION THAT DEVELOPMENT OF HCMs WOULD CREATE NUMEROUS BENEFITS IN NORTH CAROLINA.

A. Witness Auck fails to quantify the "target audience" for HCMs in North Carolina other than a reference to "smaller projects that connect to the distribution system."[20] Since a majority (>99%) of these "smaller projects" are customer-sited NEM generating facilities located on or adjacent to a retail customer's home or business, this group of customers would not materially benefit from utility investment in HCM to identify optimal locations across the utility system for siting DER. Put another way, a retail customer is not going to move its home or business a mile down the road if an HCM identifies that its premises is located on a highly saturated feeder

[20] IREC Auck Direct Testimony, at 41.

of the grid. And, again, any potential Interconnection Customer can obtain such readily available information today through either a free Pre-Request Response or by purchasing a Pre-Application Report.

Further, as stated earlier, since North Carolina enacted House Bill 589 in 2017, the Companies have recently experienced a transition away from development of distribution-connected QFs and towards larger transmission-connected solar QFs developed to compete in the competitive procurement program. Assuming this recent shift in development of utility-scale solar generation away from the Companies' distribution system continues, this also limits the audience that would benefit from an investment in HCM in North Carolina.

Q. WHAT IS THE ESTIMATED COST OF IREC'S HCM PROPOSAL?

A. IREC does not maintain information on the costs to develop and maintain hosting capacity maps and has provided no information on the projected cost for the Companies to develop its proposal.[21] Without this information there is no way for IREC to determine if HCMs are a cost-effective solution to providing grid locational guidance in North Carolina.

Q. WHAT INFORMATION DO THE COMPANIES HAVE REGARDING THE COST TO DEVELOP AN HCM?

A. Based upon public information the Company has obtained, Southern California Edison projected in 2017 that it would cost between $2-8 million

[21] Rebuttal Exhibit JWR-4, IREC's Response to the Companies' Data Request 1-19.

upfront to develop and $1-5 million a year to maintain an HCM for that utility's 4,500 circuits.[22] Recognizing Public Staff witness Lucas' position that it is appropriate to recover the costs of deploying an HCM from DG developers through fees, deployment of HCM would require a significant increase in fees to recover a cost of this scale spread across a limited audience. The effort required to develop and maintain an HCM would also compete with Supplemental Reviews and System Impact Studies for engineers experienced in interconnection studies. Therefore, the Companies continue to believe that the existing Pre-Request Response and Pre-Application Report options provided for in the NC Procedures provide Interconnection Customers reasonable access to "site specific" data. This already-available information is also generally equivalent to the data that IREC is proposing be publicized for the entire distribution system through an HCM. Importantly, the Pre-Application Report approach also directly recovers the cost from the DG developer who requested the report versus socializing the cost amongst all Interconnection Customers. Further, based on the significant drop in Interconnection Requests for distribution-connected QFs, the Companies do not believe there is sufficient justification to develop and maintain a detailed HCM for 3,900 distribution circuits

[22] California Distribution Resources Plan (R.14-08-013) Integration Capacity Analysis Working Group – Final ICA WG Report, Page 18, Table 1, *available at* https://drpwg.org/wp-content/uploads/2016/07/ICA-WG-Final-Report.pdf.

across the Carolinas, nor is there sufficient justification to independently investigate the cost of doing so.

Q. IF THE COSTS OF AN HCM ARE RECOVERED FROM DG DEVELOPERS AS THE PUBLIC STAFF RECOMMENDS, HOW MUCH WILL INTERCONNECTION-RELATED FEES INCREASE?

A. The Companies have not independently investigated the cost of developing and maintaining an HCM at this time. However, the Companies have performed some high level analysis based on the range of costs identified by Southern California Edison discussed above: approximately $2-8 million to develop the HCM and then approximately $1-5 million per year thereafter to maintain the HCM. Using the Companies' estimated 5,022 forecasted Interconnection Requests expected to be processed in 2019 (as shown in my Rebuttal Exhibit JWR-3, column 3), it would cost $398-1,593 per Interconnection Request to develop the HCM and then $199-$996 per year per Interconnection Request thereafter to maintain the HCM.

Notably, these costs would be spread across all Interconnection Requests even though the vast majority of these requests are for NEM projects that typically interconnect without issue and would not benefit from an HCM.

Q. WOULD IT BE FEASIBLE TO IMPOSE THE FULL COSTS OF DEVELOPING AND MAINTAINING AN HCM ON INTERCONNECTION CUSTOMERS?

A. No. Such a large increase in fees is unworkable in practice and IREC was unable to identify any state that has charged Interconnection Customers for the development or maintenance of an HCM.[23] Therefore, as a practical matter, the costs of developing and maintaining an HCM would have to be socialized and recovered in the Utilities' general rates.

V. Interconnection Fees

Q. THE COMPANIES HAVE PROPOSED TO INCREASE CERTAIN FEES CHARGED UNDER THE NC PROCEDURES. PLEASE ADDRESS THE PUBLIC STAFF'S AND OTHER PARTIES' POSITIONS ON THE COMPANIES' FEE PROPOSALS?

A. Public Staff witness Lucas recognizes the Commission's prior direction that DEC and DEP should not recover interconnection-related costs through the REPS Rider and should take steps to track and more fully recover interconnection-related costs through the interconnection process.[24] Mr. Lucas then states that the Public Staff has performed a limited review of the Companies' proposed modified fees but "has not audited [the proposed] interconnection fees and takes no position on them," except to reiterate the

[23] Rebuttal Exhibit JWR-4, IREC's Response to the Public Staff's Data Request 1-1(2).
[24] Public Staff Lucas Direct Testimony, at 42-43.

Public Staff's over-arching position that "costs to process interconnection requests should be borne by the Interconnection Customers and not shifted to retail customers."[25]

Dominion witness Nester supports the increased fees included in the Joint Utilities Redline filed March 12, 2018.[26]

IREC witness Auck challenges all of the Companies' proposed fee adjustments based upon IREC's general view that the Companies have been "inefficient" in their efforts to process Interconnection Requests. Ms. Auck suggests that the Companies' proposed fee increases are unreasonably large and states that the Companies have not met their burden to justify the requested fee increases. Witness Auck then compares the proposed fees to interconnection fees charged in certain other jurisdictions, and specifically takes issue with the Companies' increase in the "Change in Ownership" processing fee from $50 to $500, arguing that such a change violates the regulatory principle of gradualism and will cause "rate shock."[27]

No other party filed testimony on the reasonableness and appropriateness of either the existing or proposed fees within the NC Procedures.

[25] Public Staff Lucas Testimony, at 43-44.
[26] DENC Nester Direct Testimony, at 27.
[27] IREC Auck Direct Testimony, at 50-56.

Q. BEFORE ADDRESSING IREC'S TESTIMONY OPPOSING THE COMPANIES' PROPOSED FEE MODIFICATIONS, PLEASE COMMENT ON THE PUBLIC STAFF'S POSITION THAT ALL COSTS TO PROCESS INTERCONNECTION REQUESTS SHOULD BE BORNE BY INTERCONNECTION CUSTOMERS.

A. The Public Staff recently raised concerns in DEP's and DEC's respective 2016 and 2017 REPS Rider proceedings that the surging volume of generator interconnection requests is causing increased interconnection administration, technology, and processing costs that, absent recovery from Interconnection Customers, would be assigned to and recovered from retail customers as part of the Companies' general cost of service. As described in my direct testimony and highlighted by Public Staff witness Lucas, the Commission previously directed the Companies to track and more fully recover such interconnection-related costs from Interconnection Customers to the greatest extent possible.[28] Witness Lucas has also been clear in this proceeding that "the costs to process interconnection requests should be borne by the interconnection customers and not shifted to retail customers."[29]

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[28] DEC/DEP Riggins Direct Testimony, at 18. Public Staff Lucas Direct Testimony, at 42-43. *Order Approving REPS and REPS EMF Riders and REPS Compliance*, at 19 Docket No. E-7, Sub 1106 (Aug. 16, 2016); *Order Approving REPS and REPS EMF Riders and REPS Compliance*, at 18 Docket No. E-2, Sub 1109 (Jan. 17, 2017).
[29] Public Staff Lucas Direct Testimony, at 44.

Q. ARE THE COMPANIES' PROPOSED FEES DESIGNED TO MORE FULLY RECOVER INTERCONNECTION-RELATED COSTS FROM INTERCONNECTION CUSTOMERS, AS PREVIOUSLY DIRECTED BY THE COMMISSION AND ADVOCATED FOR BY THE PUBLIC STAFF?

A. Yes. The proposed adjusted fees are designed to address the Companies' under-recovery of interconnection-related costs and to more fully recover these costs from Interconnection Customers in the future.

Q. PLEASE FURTHER DESCRIBE HOW THE COMPANIES DETERMINED THAT THE PROPOSED INCREASE TO INTERCONNECTION FEES IS NEEDED TO MORE FULLY RECOVER INTERCONNECTION COSTS INCURRED BY THE COMPANIES THAT ARE RECOVERED THROUGH FEES.

A. As discussed in some detail in my direct testimony, the Companies have followed the Commission's prior direction in DEP's and DEC's respective 2016 and 2017 REPS Rider proceedings to track the increasing direct and indirect costs that the Companies are incurring to process Interconnection Requests. In March 2017, the Companies submitted their *Interconnection Cost Allocation Procedures Report* to the Commission, detailing the procedure and "categorization" of costs that DEC and DEP planned to follow for purposes of tracking and assigning interconnection-related costs.[30] As discussed in my direct testimony, the Companies categorize direct and indirect interconnection-related costs into three separate categories, with Category 1 capturing all "Fees Recovered Work."

Costs captured in Category 1 include the Companies' direct and indirect administration, technology, and processing costs associated with fee-recovered activities under the NC Procedures. More specifically, Category 1 costs include Renewables Service Center employee and contractor labor expense along with allocations of Distributed Energy Technologies employee labor supporting the Section 2 expedited processing of certified inverter-based generators < 20 kW and Section 3 Fast Track screening process for interconnection applications < 2 MW; processing and administration for Pre-Requests and Pre-Applications; processing and administration for Changes of Control; and related technology costs that support these areas of work.

As I described in my direct testimony, the Companies experienced a significant under-recovery for Category 1 Fee-recoverable costs in both 2017 and in 2018 based upon the fees currently in place under the NC Procedures.[31]

[30] *Interconnection Cost Allocation Procedures Report,* Docket Nos. E-100, Sub 101; E-2, Sub 1109; and E-7, Sub 1131, at 2 (Mar. 1, 2017). In the DEP REPS Order, *supra* note 2, the Commission directed DEP to work with the Public Staff in making cost allocation refinements to interconnection-related costs and to submit a report on these efforts to the Commission no later than March 1, 2017. DEP REPS Order at Ordering Paragraph 4.
[31] DEC/DEP Riggins Direct Testimony, at 21.

Q. CAN YOU PROVIDE A DETAILED BREAKDOWN OF THE COMPANIES' 2017 AND 2018 UNDER-RECOVERY AND HOW THE PROPOSED FEES WILL ALLOW THE COMPANIES TO MORE FULLY RECOVER CATEGORY 1 FEE-RELATED COSTS IN 2019 AND FUTURE YEARS?

A. Yes. Columns 1 and 2 of Rebuttal Exhibit JWR-3 provide a breakdown of the Companies' Category 1 expenses and revenues based upon experienced volumes of fee-recovered activities during 2017 and 2018, respectively. Columns 1 and 2 then present the Companies' actually-experienced under-recovery of Category 1 costs under current fees as well as projected experience if the proposed fees were in effect during each year. For 2018, Column 2 presents a calendar year 2018 breakdown of the Companies' Category 1 work, and shows that DEC and DEP have under-recovered Category 1 expenses by approximately ($584,000) in 2018 under the current fees, while the under-recovery would have approximated ($30,000) if the Companies' proposed fees were in effect. The continuing under-recovery even under the proposed fees is based upon actually-experienced 2018 volumes of Fee-related work.

Columns 3 and 4 then project Category 1 volumes, revenues and expenses for 2019 assuming that the Companies experience an additional 10% or 20% increase in Section 2 and Section 3 Interconnection Requests in 2019. Forecasting only a limited increase in Section 2 and Section 3 Interconnection Requests is reasonable for 2019 because the new

Interconnection Request volumes will largely be driven by the Commission-approved solar rebate program, which is limited to 10,000 kW of installed capacity annually. Absent the requested adjustment to the Companies' interconnection processing and other fees, the Companies project DEC and DEP to under-recover their Category 1 interconnection-related costs by over ($550,000) in 2019.

Q. PLEASE RESPOND TO IREC'S ALLEGATION THAT THE COMMISSION SHOULD REJECT THE COMPANIES' FEE PROPOSAL ON GROUNDS THAT THE COMPANIES HAVE PRESENTED INSUFFICIENT EVIDENCE TO SUPPORT THE FEES.

A. I disagree. My direct testimony explains the Companies' procedure for tracking interconnection costs and addresses that DEC and DEP significantly under-recovered Category 1 fees-recovered work in both 2017 and 2018. My Rebuttal Exhibit JWR-3 shows in detail that DEC and DEP's North Carolina Category 1 expenses exceeded the revenues generated by fees received in 2018 to complete all fee-recovered work. IREC witness Auck's own Exhibit SBA-Direct 9 (filing Duke's Responses to Public Staff Data Request 8-2) also provides additional detail on the Companies' procedure for tracking interconnection fees and experienced under-recovery of Category 1 costs. While I appreciate IREC's persistent desire for more robust activity-by-activity tracking and reporting of interconnection fees and expenses, the Companies' cost-tracking methodology is reasonable and enables DEC and DEP to determine whether the Companies are under-recovering Category 1 fee-related expenses incurred during a given year. Based upon the experienced under-recovery of this category of costs, the Companies have then reasonably allocated these expenses amongst the categories of fees in the NC Procedures.

Q. ARE THE COMPANIES SEEKING TO PROFIT FROM THE PROPOSED FEES BY CHARGING FEES THAT EXCEED THEIR PROJECTED EXPENSES?

A. No. As recognized by Public Staff witness Lucas, the Companies have "significantly increased their staffing and been required to develop administrative, technical, and information technology processes to enable third party renewable energy facilities to interconnect" and "[w]hile they pass these costs on to the developers and customers, they do not profit from any of it."[32] I agree. The Companies are not advocating for any return on their fee-related expenses to support the interconnection process, but are simply seeking to recover their Category 1 interconnection-related costs.

Q. WOULD THE COMPANIES SUPPORT REPORTING ON ANNUALIZED VOLUMES AND FEE-RECOVERED EXPENSES IN FUTURE YEARS?

A. Yes. As my Rebuttal Exhibit JWR-3 shows, changes in volumes of Section 2 and Section 3 interconnection requests can significantly impact

[32] Public Staff Lucas Direct Testimony, at 8.

whether the Companies under-recover or fully recover Category 1 expenses in a given year. Increases or decreases in expenses to support the interconnection process can have a similar impact. To the extent the Commission wants to more closely track year-over-year changes in Section 2 and Section 3 interconnection request volumes, fee-related work, and Category 1 expenses, the Companies could file an informational report with the Commission on March 1 annually similar to my Rebuttal Exhibit JWR-3. Alternatively, to the extent that the Commission plans to again review the NC Procedures and interconnection process in 2-3 years, the Companies could report to the Public Staff and other stakeholders at that time whether actually-experienced changes in interconnection fee volumes and expenses support future adjustments to fees charged under the NC Procedures.

Q. IN OPPOSING THE COMPANIES' ADJUSTED FEES, WITNESS AUCK ALSO SUGGESTS THAT INTERCONNECTION PROCESSING IN NORTH CAROLINA HAS BEEN SLOW AND INEFFICIENT WHILE SUGGESTING THE PROPOSED FEES ARE RELATIVELY HIGH COMPARED TO OTHER STATES. HOW DO YOU RESPOND?

A. I disagree with IREC witness Auck's assertion that the Companies' interconnection processing has been unreasonably slow or inefficient. Specific to the Section 2 small generator and Section 3 Fast Track study processes, producing Pre-Application Request responses and other activities where fees are used to recover the Companies' costs, the Companies have generally been meeting the timeframes required in the NC Procedures. IREC presents no evidence to the contrary. The Companies have also been working diligently to ensure they are efficiently processing the growing number of NEM Section 2 interconnection customer requests received under the solar rebates program established in House Bill 589 and recently approved by the Commission. DEC and DEP processed a combined 4,354 of Section 2 Interconnection Requests in 2018, a significant increase from the 1,406 Section 2 Interconnection Requests processed in 2017. This significant increase was primarily due to 2018 being the first year that the solar rebates program enacted by House Bill 589 was open to participation. Again, even as volumes have increased, DEC and DEP have generally processed these small generator interconnection requests within the timeframes provided for in the NC Procedures.

Moreover, while the Companies have been challenged in meeting Section 4 study process timeframes for some large multi-megawatt solar projects, DEC and DEP should not be penalized by being forced to under-recover their Category 1 expenses including implementing the Section 2 and Section 3 smaller generator interconnection processes. Public Staff witness Lucas highlights the "cooperation of the Utilities" to support North Carolina's unprecedented solar growth and the Companies are appropriately seeking an adjustment to interconnection fees to more fully recover their costs.[33]

Q. HOW DO YOU RESPOND TO WITNESS AUCK'S ARGUMENT THAT THE COMPANIES' PROPOSED FEES ARE RELATIVELY HIGH COMPARED TO OTHER STATES?

A. First, I would note that it is nearly impossible to develop accurate comparisons of interconnection fees across states and per utility, due to differing capacity ranges, carves-outs, limiters, and policy considerations varying across each jurisdiction and utility, including whether some costs are permitted to be recovered through base rates. While the Companies do not dispute IREC's presentation in Table 4 showing relatively lower fees under the approved Interconnection Procedures in Ohio, Illinois, and Virginia compared to the fees proposed in North Carolina, fees charged under other interconnection procedures seem to more closely align with the Companies' proposed fees in North Carolina.

For example, the Companies' Pre-Application Report Fee is proposed to be $500. In comparison, California's Pre-Application fees range from $300 to $1,325[34] while New York has approved a Pre-

[33] Public Staff Lucas Testimony, at 32.

[34] PG&E's Pre-Application Report Request is *available at* https://www.pge.com/includes/docs/pdfs/b2b/interconnections/pre-app-request-guide.pdf. *See also* PG&E Electric Rule No. 21, *Cal. P.U.C. Sheet No.* 40278-E (effective June 8, 2017), *available at* https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

Application fee of $750.[35] Notably, the Pre-Application fee approved under the South Carolina Generator Interconnection Procedures is the same $500 the Companies propose to charge in North Carolina.[36]

As another example, Pennsylvania has approved interconnection processing fees of $250 plus $1/kw for Generating Facilities greater than 10 kW, or $350 plus $2/kW depending on the complexity of the interconnection.[37] To translate, Pennsylvania's fees for Generating Facilities less than 20 kW could be higher than the Companies' $200 Application Processing fee proposal for less than 20 kW-sized facilities. Additionally, the Companies' fee proposal for Generating Facilitates 20 kW to 100 kW in size is comparable to New York's fee, which similarly charges $750 for facilities falling within this size range.[38] For Generating Facilities in the > 100kW to two MW range, the Companies' are proposing a $1,000 Fast Track Application Processing Fee. This $1,000 fee proposal is lower

[35] *See* New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems, at p. 9 (Oct. 2018), *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/October%20SIR%20Appendix%20A%20-%20Final%2010-3-18.pdf.
[36] *Order Adopting Interconnection Standard and Supplemental Provisions*, SC PSC Docket No. 2015-362-E, Order No. 2016-191, Order Exhibit 1 at page 37, (April 26, 2016), *available at* https://dms.psc.sc.gov/Attachments/Order/11891e05-689d-4fe7-8816-c959480feb4e.
[37] *See* 52 PA. Pa. Code §75.38 through §75.40; *see also* PECO Net Metering/Interconnection Application Fees, *available at* https://www.peco.com/SiteCollectionDocuments/summaryoffeesrev1.pdf .
[38] *See supra* at note 28.

than similar fees in Pennsylvania,[39] Minnesota,[40] Massachusetts,[41] Utah,[42] and New Jersey[43].

Furthermore, as noted above, it is also difficult, if not impossible, to correlate the fees charged by other utilities with a determination of whether those fees actually allow the utility to fully recover its interconnection-related costs. IREC candidly noted this in response to the Public Staff, explaining that the reports that the California utilities file with the California Public Utilities Commission "may not provide a complete picture of all potential costs incurred by the utilities associated with interconnection of NEM generators" and that "IREC is unaware of any state that has done a detailed tracking of overall interconnection cost expenditures."[44] Utilities that receive only a small number of interconnection requests also may not have been required to make the significant investments in human and technology resources required to support processing thousands of interconnection requests a year. Numerous states also allow

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[39] *See supra* at note 30.

[40] Generation Interconnection Application Fee Form, Xcel Energy Minnesota, *available at http://www.pacificorp.com/tran/ts/gip/qf/utah.html*; *see also* Minnesota Distributed Energy Resource Interconnection Process, Section 1.5 (issued Aug. 13, 2018), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BC0323565-0000-C93E-A016-03CA96FB9CAC%7D&documentTitle=20188-145752-03.

[41] *See* Standard Application Process, National Grid (2019), *available at* https://www9.nationalgridus.com/Masselectric/home/energyeff/4_standard-application.asp.

[42] *See* Utah Rule R746-312. Electrical Interconnection, *available at* https://rules.utah.gov/publicat/code/r746/r746-312.htm; *see also* PacificCorp, Utah, Generation Interconnection Process (2019), *available at* http://www.pacificorp.com/tran/ts/gip/qf/utah.html.

[43] *See* Building You Solar Installation, PSE&G (Dec. 19, 2018), *available at* https://nj.pseg.com/saveenergyandmoney/solarandrenewableenergy/applicationprocess.

[44] Rebuttal Exhibit JWR-4, IREC's Response to the Public Staff's Data Request 1, Topic 1.

interconnection-related costs to be subsidized through the utility's general cost of service. For example, NEM applications up to 10 kW in Florida are processed for free.[45] Overall, it is difficult to make a true "apples to apples" comparison when comparing states' interconnection fees. And given that IREC was unable to identify with any specificity the amounts recovered through base rates in other jurisdictions, IREC's proposed comparisons to other jurisdictions should not be accepted as "apples to apples" in light of the North Carolina regulatory policy directive to seek to recover all interconnection costs from Interconnection Customers.

Q. PLEASE COMMENT FURTHER ON IREC'S USE OF THE CALIFORNIA UTILITIES' INTERCONNECTION COSTS TO BENCHMARK THE COMPANIES' FEE PROPOSAL IN NORTH CAROLINA.

A. IREC witness Auck makes numerous benchmarking references to the three California utilities, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E") and, specifically, to their annual interconnection costs reports filed with the California Public Utilities Commission.[46]

[45] *See* Interconnection Agreement for Customer-Owned Renewable Generation Tier 1 – 10 kW or Less, Florida Power & Light Company, First Revised Sheet No. 9.050 (effective Feb. 20, 2014), *available at* https://www.fpl.com/clean-energy/pdf/net-metering-tier1.pdf.
[46] IREC Auck Direct Testimony, at 54-56, Exhibit SBA-Direct-10.

The Companies have reviewed the 2018 information-only annual reports submitted to the California Public Utilities Commission detailing annualized interconnection costs.[47] Based upon this review, I would initially note that the reported costs do not seem to include any recovery for technology costs, but do include processing and administrative costs, recovery for metering costs, as well as inspection and commissioning costs. It is also notable that there seems to be a significant disparity between the costs (or at least the subset of costs being reported) per application incurred between the three utilities. SCE's costs approximated $35 per application processed,[48] while PG&E's costs approximated $72 per application[49] and SDG&E's costs approximated $132 per application.[50] Little meaningful benchmarking can be ascertained from reviewing these costs, except to note the significant disparity seems to correlate to differences in costs reported and

[47] *See, Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs,* Advice 3866-E, at Attachment A, Docket U 338-E (Sept. 19, 2018); *Pacific Gas and Electric Company's Information-Only Submittal Regarding Net Energy Metering Costs,* Advice Letter 5398-E, at Attachment A, Docket U 39 E (Oct. 4, 2018); *San Diego Gas & Electric Company's Information Only Filing Regarding Net Energy Metering Costs,* Advice Letter 3273-E, at Attachment A, Table 1, Docket U902-E (Sept. 19, 2018).
[48] *Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs,* Advice 3866-E, at Attachment A, Docket U 338-E (Sept. 19, 2018) (to calculate cost per application, the "Total Costs" of $1,617,623 identified in Table 1 was divided by the total number of new applications, 46,819 identified below Table 1).
[49] *Pacific Gas and Electric Company's Information-Only Submittal Regarding Net Energy Metering Costs,* Advice Letter 5398-E, at Attachment A, Docket U 39 E (Oct. 4, 2018) (to calculate cost per application, the "Total," $4,641,650, from Table 1 was divided by the "Total NEM Applications," 64,756, identified above Table 1).
[50] *San Diego Gas & Electric Company's Information Only Filing Regarding Net Energy Metering Costs,* Advice Letter 3273-E, at Attachment A, Table 1, Docket U902-E (Sept. 19, 2018) (to calculate cost per application, the "Total Processing and Administration Costs," $3,158,628, was divided by the "# of New Applications." 23,929, taken both from Table 1).

differences in volumes of Interconnection Request applications processed by each utility during the prior year.

It is also notable that although the California utilities' costs and application volumes have change year-over-year since 2015, the application fees charged to all NEM applications projects ≤ 1 MW have not. Current application fees charged by PG&E, SCE and SDG&E are $145, $75 and $132, respectively. Interestingly, while PG&E reported costs of only $72 per application, the fee charged is significantly higher at $145 per application. Despite this annual reporting, it is difficult to meaningfully compare the fees charged by the California utilities to the Companies' proposed fees because they cover different types of costs, cover net metering projects only and cover only < 1 MW projects.

Q. DO THE CALIFORNIA UTILITIES' HIGHER VOLUMES OF INTERCONNECTION REQUESTS ALLOW FOR REDUCED PROCESSING COSTS?

A. Yes. Based upon my review of the California utilities 2018 reports, the volumes of NEM projects ranged from 23,929 to 64,756.[51] Even after significant growth compared to 2017 and prior years, North Carolina's 2018 volumes of < 2 MW projects was still significantly lower at 4,566. As IREC witness Auck notes, these significantly higher volumes allow the California utilities to "benefit from economies of scale."[52] This is

[51] *See supra* note 47.
[52] IREC Auck Direct Testimony, at 55.

important because a certain amount of "fixed cost" infrastructure and resources are required to support processing thousands of interconnection requests during a given period. Where the utility is processing greater volumes of applications, these costs can be spread out and reduced for each individual Interconnection Customer. Further, once the infrastructure costs are recovered, I agree with IREC that efficiencies can reduce the ongoing per application charge. Thus, the California utilities have experienced significantly higher volumes of < 1 MW projects for many years and that has allowed infrastructure and efficiencies to be built into its cost base over time. The Companies are only now starting to make the infrastructure investments to support the greater volumes of small NEM Interconnection Requests and are only now making the fixed cost investments in Salesforce and other infrastructure to support this process.

Q. IREC SPECIFICALLY ARGUES THAT INCREASING THE CHANGE OF CONTROL FEE FROM $50 TO $500 OR BY "1,000 PERCENT" IS UNREASONABLE. DO YOU AGREE?

A. No. As background, a change of control occurs when an Interconnection Customer transfers ownership of the Generating Facility or sells its ownership interest in the legal entity owning the Generation Facility, thus "changing control" of the existing legal entity that is the counter-party under the IA and responsible for operating the Generation Facility. Changes of control therefore most often occur in the context of utility-scale developers "flipping" projects to other developers.

The $50 fee currently in place has never been sufficient to allow for the recovery of the Companies' costs incurred to complete a change of control, and the increase to $500 more accurately allows the Companies' to recover their costs. Specifically, based on analysis the Companies have performed on the costs and time incurred to complete a change of control, it takes on average six hours to complete all administrative process required to document a change of control for a larger independent power producer. Additionally, if there are legal complications with the change of control, more time must and expense must be incurred. Thus, on average, the direct administrative cost of processing each change of control are at least $400. Note also that this $400 does not include technology costs in addition to supervisory time or legal costs. As another comparison, a change of control requested under a large QF generating facility power purchase agreement is $10,000, making $500, by comparison, seem extremely reasonable for processing a change of control for a standard IA.[53] Therefore, the Companies' proposed $500 fee to process a change of control is reasonable and consistent with the Commission's directive to recover costs to the greatest extent possible from Interconnection Customers.

[53] *See* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Final *pro forma* CPRE Tranche 1 PPA, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, Attachment A at Section 24.6 (filed June 8, 2018) (approved by the NCUC's *Order Denying Joint Motion, Approving Pro Forma PPA, and Providing Other Relief,* Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 on June 25, 2018).

Q. IREC ALSO ARGUES THAT RATEMAKING PRINCIPLES OF GRADUALISM SHOULD BE APPLIED TO REDUCE THE PROPOSED FEES. DO YOU AGREE THAT THIS PRINCIPLE IS APPLICABLE HERE?

A. No. From a layman's perspective, a principle of gradualism seems inapplicable in this context because an Interconnection Customer only pays an interconnection fee once. By comparison, retail customers who pay fixed charges for service on an ongoing basis. Thus, because an interconnection-related fee is only charged to an Interconnection Customer once, the principle of gradualism does not seem applicable.

Q. ARE THE COMPANIES PROPOSING TO MAKE ANY CHANGES TO ITS CHANGE OF CONTROL FEE PROPOSAL AT THIS TIME?

A. Yes. In light of the fact that the change of control administration process is more simplified for small Interconnection Customers, the Companies have bifurcated the change of control fee to retain $50 for the smallest Interconnection Customers 20 kW or less that enter into the consolidated Attachment 6 Application and IA report. The proposed $500 fee will apply to all Interconnection Customers above 20 kW that submit an Attachment 2 Interconnection Request Application Form and enter into the full Attachment 9 Interconnection Agreement.

Q. HAVE THE COMPANIES ALSO CORRECTED THE PROPOSED SECTION 2 PROCESSING FEE WITHIN ATTACHMENT 6?

A. Yes. The Duke Energy Redline filed with the Companies' direct testimony inadvertently did not modify the processing fee within Attachment 6 for Section 2 Interconnection Customers (Certified Inverter-Based Generating Facility No Larger than 20 kW) as supported on pages 23-24 of my direct testimony. This processing fee has been updated in Attachment 6 of Rebuttal Exhibit JWG-1 to accurately reflect the Companies' proposed fee of $200 as discussed in my direct testimony and further supported above.

VI. <u>Dispute Resolution</u>

Q. THE COMPANIES HAVE PROPOSED SEVERAL MODIFICATIONS TO THE DISPUTE RESOLUTION PROCESS UNDER THE NC PROCEDURES. PLEASE ADDRESS THE PUBLIC STAFF'S AND OTHER PARTIES' POSITIONS ON THE COMPANIES' MODIFICATIONS?

A. As discussed in my direct testimony and the rebuttal testimony of DEC/DEP witness Freeman, the dispute resolution process contributes to delays in the interconnection process. Such delays are exacerbated by the ambiguity in the NC Procedures regarding the associated timelines.

Public Staff witness Lucas stated that the Public Staff should continue to be involved in informal dispute resolution process, but that a third-party dispute resolution service should be another option to resolve disputes if mutually agreed by both parties.[54] To that end, Public Staff proposed certain modification to the Section 6.2 of the NC Procedures.

IREC witness Auck states that a new, "clearly defined" dispute resolution process is needed in North Carolina and should include an interconnection ombudsperson at the Commission who would help facilitate dispute resolution.[55]

DENC witness Nester believes that the existing dispute resolution process is sufficient and that IREC's proposal to add an ombudsperson is supported by little evidence.

Q. HOW DO THE COMPANIES RESPOND?

A. As stated in my direct testimony, the Companies maintain that the Public Staff's involvement, technical understanding, and perspective has been very valuable during the dispute resolution process and has allowed the Companies and Interconnection Customers to successfully resolve nearly all disputes.[56] Since submitting direct testimony, the Companies have engaged in discussions with the Public Staff regarding witness Lucas' proposal for the Companies and/or Interconnection Customers to be permitted by mutual agreement to engage a "dispute resolution service" as part of the informal dispute resolution process. The Companies are concerned that this alternative process is undefined and could also

[54] Public Staff Lucas Direct, at 37-38.
[55] IREC Auck Direct Testimony, at 46.
[56] DEC/DEP Riggins Direct Testimony, at 33.

significantly extend the timeframes for informally resolving disputes, thereby further delaying later-queued interconnection customers. The Companies also believe the Public Staff has informally facilitated the role of an "interconnection ombudsperson" in North Carolina, when needed, and no further formalization of this role is needed or appropriate at this time. The Companies plan to continue to discuss this issue with the Public Staff, but, at this time, continue to support the proposed modifications to Section 6.2 that I sponsored in my direct testimony.

VII. Surety Bonds

Q. HAVE THE COMPANIES PREVIOUSLY COMMITTED TO ACCEPT SURETY BONDS FROM INTERCONNECTION CUSTOMERS AS FINANCIAL SECURITY IN PARTICULAR SITUATIONS?

A. Yes. The Companies have previously committed to accept surety bonds from Interconnection Customers that contain terms that are reasonably acceptable to the Duke Energy credit and risk management ("Credit/Risk") department in the following circumstances:

- As security pursuant to NC Procedures Section 4.3.9 in the case of an executed state-jurisdictional Facilities Study Agreement with identified Network Upgrades;
- In connection with Competitive Tier Proposals (*i.e.*, Proposals that are determined by the Independent Administrator to move into Step

2 of the CPRE Evaluation Process) that are required to post "Proposal Security."

- Executed state-jurisdictional IA with identified Interconnection Facilities but no Network Upgrades when the project is participating in the CPRE evaluation process until such time as the outcome of the CPRE Tranche 1 RFP is determined.
- Executed state-jurisdictional IA with identified Interconnection Facilities and Network Upgrades that will not be completed for 3-5 years and project would not begin final design, procurement and scheduling of Interconnection Facilities construction for an extended period of time after the IA was executed.

Q. ARE THE COMPANIES WILLING TO ACCEPT SURETY BONDS FOR INTERCONNECTION FACILITIES IN SCENARIOS OTHER THAN THE SCENARIOS DESCRIBED ABOVE?

A. Yes, in those circumstances in which either DEP or DEC have previously accepted security for Interconnection Facilities or any circumstance in which there is a material lag between the execution of the IA and the date on which the Companies begin to incur costs for the Interconnection Facilities, the Companies are willing to accept surety bonds as security until such time as the Companies begin to incur costs or would otherwise require payment. For the avoidance of doubt, any surety bond must contain terms that are acceptable to the Companies' Credit/Risk Department in their sole, reasonable discretion.

Q. WHAT ARE THE PRIMARY TERMS AND CONDITIONS THAT MUST BE REFLECTED IN ANY SURETY BOND IN ORDER TO BE ACCEPTABLE TO THE COMPANIES?

A. The most crucial terms and conditions include, but are not limited to, the following:

- Must require payment to Duke in the event of the principal's failure to perform
- Payment must be made by the surety to Duke within a short period of time (*e.g.*, 10 days)
- Surety bond must be irrevocable by the Surety and noncancelable by the principal, or, alternatively, surety must be required to provide Duke prior notice of cancellation and Duke has right to demand payment if alternative security is not provided 30 days prior to cancellation
- Waiver of suretyship defenses
- North Carolina governing law and forum

A form surety bond that was provided by the Companies in connection with the CPRE RFP and contains generally acceptable terms and condition is provided as Rebuttal Exhibit JWR-5. This particular form would need to be significantly updated for use in the interconnection context.

Q. WHILE THE COMPANIES ARE WILLING TO ACCEPT SURETY BONDS FOR INTERCONNECTION FACILITIES AS DESCRIBED

ABOVE, DO THE COMPANIES AGREE THAT SURETY BONDS ARE "WIDELY ACCEPTED" IN THE UTILITY INDUSTRY AS WAS ASSERTED BY WITNESS NORQUAL?

A. No. In response to a data request, NCCEBA was able to identify only one other utility that has accepted a surety bond in the interconnection context.[57]

Q. WHY DO YOU THINK THAT IS THE CASE?

A. While I am not an expert on credit issues, I have been advised by the Duke Energy Credit/Risk department and Duke's internal legal team that surety bonds generally contain terms and conditions that provide less security than letter of credit. For instance, surety bonds generally contain more detailed pre-conditions to the assertion and payment of a claim by the non-defaulting party, which effectively provides less certainty that the Companies and its customers will be protected in the event of default. In contrast, when the Companies receive financial security in the form of letters of credit or cash pre-payment, the Companies have more unfettered rights to draw on those forms of security without the potential need for legal action to enforce its rights. In addition, surety bonds are less standardized than letters of credit, more complex and can have much greater variability of commercial terms, which would, in turn, require more in-depth, case-by-case analysis to confirm acceptability as well as, in some cases, further negotiation concerning such terms.

[57] Rebuttal Exhibit JWR-4, NCCEBA's response to the Companies' Data Request 1-15.

Finally, the Duke Energy Credit/Risk department has advised me that the assertion that the Companies have the ability to prescribe the surety bond form is generally inconsistent with our previous experience. More specifically, the Companies historically have been unable to secure any material changes in bond form language in the few instances where we determined that we would consider acceptance.

Q. WHY ARE THE COMPANIES NOW WILLING TO ACCEPT SURETY BONDS CONTAINING ACCEPTABLE TERMS AND CONDITIONS FOR INTERCONNECTION FACILITIES IN THE CIRCUMSTANCES DESCRIBED ABOVE?

A. While surety bonds will generally provide less certainty and consume more of the Companies' resource for purposes of review and negotiation, the Companies in the interest of compromise and due to the fact that the financial risk to other customers is lessened in the case of Interconnection Facilities if the security arrangement is properly structured.

Q. WITNESS NORQUAL ALSO STATES THAT "DUKE SHOULD NOT BE PERMITTED TO RETAIN THE FUNDS…OF INTERCONNECTION CUSTOMERS FOR INTERCONNECTION FACILITIES IF THE INTERCONNECTION FACILITIES ARE NOT CONSTRUCTED AND DUKE HAS NOT HAD TO INCUR ANY COSTS." TO BE CLEAR, HAS DUKE EVER RETAINED INTERCONNECTION CUSTOMER FUNDS WHERE

PARTICULAR INTERCONNECTION FACILITIES WERE ULTIMATELY NOT CONSTRUCTED?

A. No. Further, NCCEBA and CCR were also subsequently unable to identify any instances that supported the statement that the Companies ever "retained" interconnection customer's funds where Interconnection Facilities were not constructed. Instead, the statement appears to have been intended to refer to those situations in which there was some period of time between payment for the Interconnection Facilities and commencement of construction.[58]

VIII. Other Issues

Q. DID THE PUBLIC STAFF OR INTERVENOR TESTIMONY COMMENT ON ANY OTHER RECOMMENDATIONS MADE IN YOUR DIRECT TESTIMONY?

A. Yes, the Public Staff witness Lucas and North Carolina Pork Council witness Maier both agreed with the Companies' proposed revisions to Section 1.8.3.3 of the NC Procedures related to an expedited review process for swine and poultry waste to energy projects of two MW or less.[59]

Public Staff witness Lucas also supported the Companies' proposed addition of Section 1.8.3.4 of the NC Procedures related to expediting the

[58] Rebuttal Exhibit JWR-4, NCCEBA's response to the Companies' Data Request 1-17.
[59] Public Staff Lucas Direct Testimony, at 50; North Carolina Pork Council Maier Direct Testimony, at 9-10.

study process for standby generators requesting momentary parallel operation.[60]

No other parties commented on these two topics.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[60] Public Staff Lucas Direct Testimony, at 19-20.

BY MR. BREITSCHWERDT:

Q And, Mr. Riggins, did you prepare a summary of your testimony for the Commission today?

A I did.

Q Would you please present it at this time?

A Good afternoon, Commissioners. My name is Jeff Riggins and I am the Director of Generator Interconnections and Standard Purchase Power Agreements for Duke Energy. I appreciate the opportunity to share with this Commission the efforts my team and others in the Distributed Energy or DET organization have made to support the interconnection process in North Carolina, and to ensure that we are safely and reliably integrating renewables and other distributed generation into the Duke systems. My team is 100 percent dedicated to the interconnection process and works on a daily basis --

CHAIRMAN FINLEY: Speak up please, sir. We're having trouble hearing you in the back. Pull that mic up a little bit.

THE WITNESS: Would you like for me to start again?

COMMISSIONER GRAY: Please.

CHAIRMAN FINLEY: Please go ahead and start again.

(WHEREUPON, the summary of JEFFREY W. RIGGINS is copied into the record as read from the witness stand.)

Testimony Summary – Jeff Riggins

Docket No. E-100, Sub 101

January 28, 2019

Good afternoon Commissioners. My name is Jeff Riggins and I am the Director of Generator Interconnections and Standard Purchase Power Agreements for Duke Energy. I appreciate the opportunity to share with this Commission the efforts my team and others in the Distributed Energy Technologies or "DET" organization have made to support the interconnection process in North Carolina and to ensure we are safely and reliably integrating renewables and other distributed generation into the Duke systems. My team is 100% dedicated to the interconnection process and works on a daily basis to improve our capabilities while also processing the unprecedented number of small and large interconnection requests that we have received.

Since I joined DET in 2016, Duke Energy has added significant engineering and administrative resources and enhanced the information technology tools that we use to monitor and track interconnection requests and communicate with customers. As I highlight in my direct testimony, Duke Energy has significantly expanded the DET and engineering teams that support the administration of the interconnection process for larger customer-sited generating facilities and for third-party developers. We also formed the Renewables Service Center to provide small customer-focused technical support and to more efficiently process the 1000s of small interconnection requests we receive from our customers each year. Today, we have over 100 individuals committed to supporting the generator interconnection process in the Carolinas.

I also actively participated in the 2017 AE-led stakeholder meetings in Raleigh and since that time I've been leading my team and collaborating with other Duke Energy teams to improve transparency and the interconnection customer experience. Our current focus is on improving interconnection customer communications and leveraging IT tools, such as the Salesforce platform that I discuss in my testimony, to track and manage interconnection requests and to enable both the Companies and our customers to better meet the timeframes established in the interconnection procedures. We are also developing a web-based customer portal which will be available in early 2019. This new customer portal will enable the Companies to more proactively communicate with our customers regarding their interconnection requests and to provide status updates in more real time. Many of the changes Duke has proposed in this proceeding are also intended to support these efforts and to make the interconnection process more transparent and efficient for our customers as well as third-party developers.

My testimony also specifically supports certain limited changes to the NC Procedure to improve the interconnection study process for Interconnection Customers. We recognize that customers want to progress through the study process as quickly as possible, so we proposed a change that allows customers eligible for Section 3 Fast Track Review to authorize a Supplemental Review in advance so we can eliminate the current processing delay associated with collecting the additional deposit required for Supplemental Review. To provide more information to customers earlier in the interconnection process, we are also proposing to provide an Enhanced Scoping Meeting to share more details about a proposed interconnection location prior to the customer proceeding to the full System Impact Study review. Finally, we proposed changes to expedite the study of swine and poultry waste projects to meet the directives of HB 589 and for standby generator requests which are often proposed by sensitive commercial customers like hospitals and technology companies facilities for reliability reasons.

Through this proceeding, Duke Energy has also made a focused effort to more appropriately assign the cost of administering the interconnection process to interconnection customers. My testimony supports the Companies' proposal to adjust the fees charged for small generator studies and certain other work under the Interconnection Procedures to more fully recover the Companies' actually-incurred costs, including the costs of adding personnel and making technology investments to support the interconnection process. We have designed the fees to reasonably recover our fee-related costs in 2019 based upon anticipated volumes of new interconnection requests. Should actually-experienced volumes of interconnection requests deviate significantly from projections, Duke would support a future review of interconnection fees to ensure they remain reasonable for our customers and fully recover the utility's cost of supporting the interconnection process.

In conclusion, I am proud of the commitment Duke Energy has made since 2015 to safely and reliably interconnect more utility scale distributed generation to the grid than any other utility in the country. I am even more proud of the work ethic and commitment I witness every day from the people in the Distributed Energy Technologies organization to support the interconnection process in North Carolina.

Thank you again for the opportunity to share my perspective on the interconnection process and our commitment to its success, and I look forward to answering your questions.

MR. JIRAK: Thank you, Mr. Riggins.

Mr. Chairman, that concludes the summaries, and the witnesses are available for questions from the Commission and other parties.

COMMISSIONER BEATTY: IREC, cross examination?

MS. BEATON: Yes. Thank you, Mr. Chairman. Can you hear me okay?

CHAIRMAN FINLEY: Yes.

MS. BEATON: Great. My name is Laura Beaton and as I mentioned earlier I represent the Interstate Renewable Energy Council or IREC. I'll start with questions intended for Mr. Gajda.

CROSS EXAMINATION BY MS. BEATON:

Q So hi, good morning -- or good afternoon.

A (Mr. Gajda) Good afternoon.

Q Mr. Gajda, in your direct testimony on pages 45 through 46, you discuss the concept of Good Utility Practice, and do you agree that Good Utility Practice requires that Duke engage with other utilities or standards bodies regarding appropriate interconnection technical practices?

A Can you hear me okay? Great.

So I would agree that it is

important for, in general for Good Utility Practice for Duke to engage with standards bodies and these sorts of organizations when there are standards that exist. I can briefly give an example of IEEE, National Electrical Safety Code committees, Southeastern Electric Exchange, as examples of committees and organizations that Duke has been involved in for many decades. Where those organizations have standards or practices that apply, it not only makes sense that Good Utility Practice states that those are the sorts of things that we should be looking for.

In North Carolina, the challenge has been that the types of interconnections we've been seeing have been so unprecedented that these other organizations have often not had practices to look towards and in that case Good Utility Practice has to utilize our internal understanding of the power system as we continue to engage the industry.

Q And thank you. And you discussed there engaging with standards bodies, would you say that Good Utility Practice also would require Duke talking

to other utilities about the practices they use?
A Yes, I would agree when possible. There are many utilities in the United States, and I think it is most effective for us to engage with those other utilities as part of standards bodies, for example, IEEE. It's -- I will admit it's challenging to engage directly with many, many other utilities when we're able to do that. When we think that there are practices that may apply we certainly attempt to do that.
Q And does Duke regularly engage and consult with other utilities and research bodies? You were explaining to me that you think you should and so now I'm asking do you engage with other utilities and research bodies regarding your interconnection practices?
A My only challenge in answering your question would be what -- not to be coy but what the definition of "regularly" is. We -- I guess just to further expand and I think to help the question is we're in a normal habit of engaging in these standards bodies such as IEEE and NESC and such, when we see interconnection challenges as we've seen in North Carolina then at that

point we have to attempt to look around and see where does it make sense to contact other utilities that may be experiencing similar things, and we have done that. Again, tough to define "regularly".

Q Thank you. So now I have a few questions about Fast Track and Supplemental Review for you. And first to make sure we're on the same page here for the next set of questions, I want to make sure we're on the same page about the Fast Track process. So my understanding is that the Fast Track process in Section 3 of the North Carolina Interconnection Procedures is the process by which certain smaller eligible projects go through a set of technical screens to determine whether that project can be interconnected safely and reliability without going through the full Section 4 study process; is that correct?

A I'd say that's a good general characterization. Yes.

Q Thank you. And when a project fails the Section 3 -- when the project fails a Section 3 Fast Track screen, what generally happens to the project?

A So that -- in general, while there is flexibility in the Interconnection Standards to do several things the most common thing if a screen has failed is for the project to be referred to the Supplemental Review process.
Q And Supplemental Review is where a project undergoes some additional review to see if it can be interconnected safely and reliably without a full Section 4 study, correct?
A That would be a summary description, yes.
Q Thank you. And if a project fails the Fast Track process and must go on to Supplemental Review, if the utility determines it should go on to Supplemental Review, how much time does that add to the process for the customer?
A It's very hard to say. That's very project specific. In many cases if a single screen is failed in the Fast Track process it will move to Supplemental Review and it -- again, very hard to give you a number. It's very relatively project specific.
Q And trying to find some number we can point to, would you say that under the procedures it may take 35 to 45 days if the maximum time allowed

under the procedures is followed?

A That would be the time under the procedures which encompass a number of things. The actual physical time to study the project under Supplemental Review, assuming you had every bit of information in front of you and an engineer was completely engaged hour-by-hour, would typically be significantly less than that.

Q And you don't have any idea of what the average time is for a project undergoing Supplemental Review.

A I don't specifically in front of me, no.

Q Okay. So if a project fails Fast Track and must go on to Supplemental Review does it cost the customer more money?

A Yes. The Supplemental Review process is designed to capture the additional cost of the, the additional time it expended; that's correct.

Q And if fewer projects moved to Supplemental Review, if more could appropriately pass Fast Track, would Duke have more staff time and resources available for study of other projects or other aspects of the interconnection process?

A Do you mind asking that question one more time?

Q Let me try and ask it in a different way. If Duke engineers weren't performing Supplemental Review of projects that hypothetically didn't need it, would those engineers have more time to do other things?

A That's a very difficult question to answer. The way you ask it, the obvious answer perhaps you're looking for is theoretically yes. I would say that the premise of the question is a little tough because it gets into whether or not there is a need for that project to be looked at, which is kind of the whole point of the -- part of the Fast Track screens.

Q And, currently, my understanding is that most projects that go through the Fast Track process with Duke fail the Fast Track process. Around 98 percent do not pass a Fast Track screen; is that correct?

A I believe that's correct.

Q But my understanding is also that almost all of these projects that fail Fast Track pass -- that go on to Supplemental Review do pass Supplemental Review; is that correct?

A That is my understanding, yes.

Q Great. And, Mr. Gajda, currently when a customer goes on to Supplemental Review, do they know what technical analysis Duke is going to perform as part of the Supplemental Review process?
A Do they know -- I'm sorry. Let me ask you a question for clarification. Are you asking if they know, prior to us entering Supplemental Review, if they know what analyses we're going to perform?
Q Or what the menu of analyses is. Do they have any idea of what analysis Duke will perform during Supplemental Review?
A Yeah. The current Supplemental Review process is designed to be very flexible. Our general assumption has been that customers are interested in interconnection, they're not interested so much in the technical analyses and so -- so, therefore, we proceed through the Supplemental Review certainly happy to describe anything the customer may be curious about. But, in general, somebody interconnecting 100 kilowatts on a roof is probably not interested in some of the deep electrical analyses. That's kind of our assumption going in. The flexibility of the

procedure allows us to perform really the minimum amount of analyses necessary to assure that it can be interconnected safely and reliably.

Q So in some of the responses to IREC's data requests and in your testimony, you described some of the screens that might be applied in the supplemental -- in Duke's current Supplemental Review process; is that correct?

A I believe that's correct, yes.

Q And is there any way for a customer to also access that information to get a preview of what the technical analysis might be?

A Again, not currently because of the nature of how the Supplemental Review process is structured. And again, our assumption is customers are interested ultimately in interconnecting in a reasonable period of time. So no there is not a preset list and we believe that's a benefit because we wouldn't want there to be a preset list. We'd want to be able to perform the minimum that's required.

Q Understood. But have you considered that projects might be better designed to avoid impacts if interconnection customers could better understand the standards and screens that they would need to meet to pass Supplemental Review, even if they understand that not all of them may be applied, but the customers would have a preview of what review would be applied?

A That -- in all fairness and with respect that sounds reasonable. I think we believe in actual practice that we believe that that's not necessarily the case. Because often times a customer may not by aware of -- understandably aware of the nature of the internals of the utility system and whether or not there's a particular type of voltage regulator in a certain place or a certain size wire, but that wouldn't necessarily in many cases provide a lot of life for them. And furthermore, most Fast Track interconnections, most are by customers who are not selecting a site because they are already a retail customer at a specific location.

Q And as we discussed and you confirmed, Duke has provided a list of screens it may typically use for Supplemental Review, has provided that as part of this proceeding. Is Duke opposed to making public that list that it currently uses so interconnection customers could access it if they wanted to?

A Duke's not interested in keeping anything secret. I think the only hesitation in providing that would be that as soon as we provide that list there is the possibility that it could change. We would -- and this has already occurred. We -- you know we find over time efficiencies and certain things that at one time maybe we thought needed studied and now they don't. And so as soon as we provided something like that we would -- there could be a chance that it would change and I think that's a lot of work and a lot of time and not necessarily a lot of customer benefit.

Q Thank you. So now I'm going to ask you some questions about Duke's application of Screen 3.2.1.2, otherwise known as the 15 percent of peak load Fast Track screen. And is it correct that most projects that fail Fast Track in Duke's territory do so because they fail that 15 percent of peak load screen?

A It's my understanding that that is. That's one of the most common, yes.

Q And is it your position that Duke's interpretation of line section in its application of the 15 percent of peak load screen is the only way to maintain safety and reliability on Duke's system?

A We believe that our interpretation of line section is consistent with the way line section is described in terms of its definition. The challenge with the screens is that the screens themselves are the screens. We can't change the screens. We can't come up with different screens to insert in the Interconnections Standards. They're already there so we operate with those screens as they are. So to the degree that the screen provides value in getting visibility down at that area of the -- of how we interpret line section. Yes. I mean, yes, we do believe that that our interpretation of line section provides a valuable flagging mechanism for potential impacts.

Q And do you believe there are other appropriate or -- let's not use the word appropriate. Do you believe that there are other possible interpretations of line section than the one that

Duke currently uses?

A Well, clearly through all of the testimony and back and forth, there are other interpretations of line section, and this has been discussed extensively in this proceeding. We're aware of that. And Duke has maintained this because, I think for probably two primary reasons, one is electrically, and we had discussions within our own engineering team talking about early on about the fact that should line section be one thing, should it be another, and the way that we currently interpret it is meets with the exact nature of the words involved. They talk about protective devices. And so we stuck with a definition that in our understanding met with the definition that was in the Standards. And we also really remained with that definition because the other interpretations of line section which go to subsections of circuit, subsections of feeders, those -- there was really nothing electrically different between that and the various relatively smaller definition of line section that we currently utilize. So because there is nothing electrically different and our

understanding of the testimony of kind of back and forth between IREC and other parties we don't believe that that's actually been challenged, what we just see is that the interpretation is sometimes different. But, again, we have chosen to interpret it as we believe it's strictly defined and as we believe it's electrically consistent with physics.
Q Okay. And, you know, as you've mentioned the record indicates that in other states other definitions of line section may be applied and it's -- in other states there's evidence in the record that it's still common for projects to pass the 15 percent of peak load screen. Have you or anyone else at Duke attempted to learn how other utilities may be applying the screen or the definition of line section in light of these distinctively different passage rates?
A So I think this is an active area of interest for Duke, and I say this very honestly because this came up -- because of the fact that the bulk of our interconnection as we know have been more utility scale and not so much net metering. There's still a significant quantity but not so

much as perhaps in California, et cetera. This has been a growing area of interest that I think has really grown around our interconnection stakeholder process. We've described in testimony that we are very interested in fresh looks at these screens. Our understanding is that this particular screen really goes all the way back to California, Rule 21 in the 1990's. Physics doesn't change our understanding of how things work on the system, perhaps adapts and improves. So we really support a fresh look at the screen and I think that's become evident during the stakeholder process. The timing of everything and a lot of where our efforts have been focused have not allowed us to really deeply look and consider whether a different interpretation makes sense, at least between stakeholder process of today.

Q But you're saying that as of today, as of right now, Duke is opening -- is open to reviewing its application of the screen and seeking perhaps an outside review?

A Well, I believe we stated this in testimony that we're interested in a review of the screens for the sake of North Carolina, and -- you know, we're interpreting the screen as we see it currently standing. We think that that is -- the way it currently sits is a valuable interpretation and that may very well continue to be that. And I don't think that the stakeholder process, the way it was structured, allowed for an in-depth technical analysis of the screens. I think there were various parties that came forward, but it didn't allow for an in-depth technical analysis and national comparisons and these sorts of things. So we stand by the screen as it's currently done today but certainly we're always willing to learn what's happening in other jurisdictions.

Q And --

A (Mr. Freeman) Well, can I jump in?

Q Absolutely.

A You asked the question about have we had conversations with other utilities or even consultants on what other states are experiencing. This isn't directly around Fast Track screens. But I'd like to share that we've had conversations with at least one consultant who has been working with Hawaii. So Hawaii is in a much similar state as Duke but in a different way. Hawaii has connected up - gosh, I've lost track as to how many rooftop facilities they've connected up - but probably three years ago it was 70,000. I'm sure they're way in excess over 100,000 now. And under the small, kind of under 20kW, I'll call it not screen but process, they've realized that they've connected up a tremendous amount of rooftop facilities to individual homes and they're now seeing even that the aggregate amount of rooftop solar is causing voltage issues even at the service transformer, at the service line, and they're starting to see that they've got to make -- they've got to -- they're now doing, it's not full system impact studies but it is a combination of study to understand the impact of large amounts of penetration at that level. So we are having conversations with other utilities. And there's an example where they're much -- very similar to us in terms of they've got an extremely high penetration, different because it it's rooftop, where ours is mostly larger scale.

Q Thank you. Mr. Gajda, I think those are all the questions I had specifically directed at you.

And now Mr. Riggins I'd like to ask you some questions about transparency into Duke's implementation of the interconnection process. So my first question is does Duke track its work as it processes applications through each step of the procedures?

A (Mr. Riggins) Yes.

Q Great. And so in your rebuttal testimony at page 21 and, if you want to look the it, lines 5 through 15. I'll let you open it up.

A Tell me which page.

Q Page 21,lines 5 through 15.

A Okay.

Q And there you say it would be burdensome for Duke to provide more detailed reporting on how it meets different interconnection process timelines than it does right now; is that correct?

A To the degree that it was spelled out in the exhibits in your testimony, that is correct. We thought it would be overly burdensome to provide all of that level of detail.

Q And is it true that Duke already tracks completion of many of the milestones through the interconnection process, even some of those that were listed in IREC's requested reporting requirements?

A Certainly we track a lot of the data points that were listed. Others would require further investment in our sales force application to be able to track on that level of detail. We're already publishing a queue report updated two times per month that provides the status of projects. And to be honest some of the data that we found in the exhibit we also thought would be commercially sensitive and shouldn't be published; things such as cost. So much of that information that was listed is provided directly to customers in the forms of emails and other communications as we update individual projects on their status. So we feel like there's a certain information that should be provided in that manner and other information that should be provided much like we do today in our queue reports.

MR. JIRAK: Mr. Riggins, just a reminder, if you could you pull that mic a little closer to you --

THE WITNESS: (Mr. Riggins) Okay.

MR. JIRAK: -- so the Commissioners can hear you a little better.

CHAIRMAN FINLEY: Pull that black one around, too, so you can talk into both of them.

THE WITNESS: (Mr. Riggins) Okay.

MR. JIRAK: Thank you.

COMMISSIONER GRAY: Thank you.

BY MS. BEATON:

Q And do you agree or disagree that providing more detail on Duke's compliance with certain milestones for projects under the procedures would be informative to the Commission and other stakeholders, other than the individual interconnection customer that the project is relative to, would be informative to the Commission and other stakeholders on how the process is going? How the whole procedures are working.

A Certainly informative. There's certain information that we already provide in the performance reports that we provide to this Commission and that should give some indication as to how the process is working. There's also a balance we believe in terms of how much effort and time and money we want to spend on reporting. And certainly that would detract away from the resources we have focused on completing studies. So we believe that we provide an adequate balance on reporting and at the same time doing the work that we're trying to be diligently completing.

Q And in Duke's -- and if you don't have a copy I can pass it to you -- but in Duke's response to IREC's Data Request 1-4 -- do you have that or do you need a copy? It's attached as Exhibit 8 to Sara Baldwin Auck's direct testimony as well.

A I have some of them but if you have it, it may be more efficient.

Q Yes, I have copies here. I'm going to provide you with a copy. And this is already in the record but for everyone's convenience it's easier.

MR. BREITSCHWERDT: Thank you.

BY MS. BEATON:

Q So I'm going to ask you a question related to Duke's response 1-4f. It's on the third page of this little handout. And this is a list of all the data points that the Duke Companies are currently tracking as part of its interconnection process. And my question is would it be so burdensome to provide this information publicly as part of the queue report since it's already being tracked?

A So in our response on Part F we identified that a -- there are a number of data points that are currently being tracked and we identified some that are not.

Q Correct. And I'm asking about the ones that are currently being tracked that Duke already tracks.

A Certainly to the degree that they're already being tracked and that they're appropriate to be publicly shared and posted, then I would think that should be reasonable. But our biggest concern again is the investment in additional coding and sales force to track data points that we're not tracking today. And then also to some degree detracting away from the resources that we have currently applying to completion of studies.

Q Thank you. And now, regarding your testimony about other states that have timeline enforcement mechanisms in place like New York or Massachusetts, do you believe utilities in other states such as New York or Massachusetts face no circumstances outside of their control when complying with timelines such as customer delays?

A Can you state the question again to be more clear?

Q Sure. Well, let me -- in -- now I'm going to apologize. I don't remember if it was your testimony or Mr. Freeman's testimony. In one of your testimony you discussed outside forces that cause delays such as interdependency or when you throw the ball back into the customers court. And do you believe that utilities in other states that have timeline enforcement mechanisms don't also encounter those same sorts of problems?

A I'm not sure what they encounter in other states.

Q Mr. Riggins, you note in your rebuttal testimony at page 13, lines 1 through 12, that one of the reasons that you think a timeline enforcement mechanism would not work in North Carolina is because the utilities here under the procedures face having so many interdependent projects; is that correct?

A State the question again, please.

Q Yes. You note in your testimony, page 13, lines

1 through 12, that one of the reasons that you think a timeline enforcement mechanism would not work in North Carolina is because of the number of interdependent projects which extends the time that it takes for a project to make it through the process?

A Yes.

Q Is that correct?

A Among other things.

Q Yes. Yes, that's one, one reason. And do you think it would be possible to simply create a program that - a timeline enforcement program - that stops the clock when a project is in a waiting phase under interdependency?

A I suppose it's possible but you would need to also create a clock for all the other things that delay projects as well, and certainly that becomes administratively challenging with the volume of projects that we're handling today.

Q Thank you.

Now, Mr. Freeman, I have a few questions for you. In your rebuttal testimony at page 7, lines 16 through 20 - I'll let you get it first - rebuttal page 7.

A (Mr. Freeman) I'm there.
Q Rebuttal testimony page 7, lines 16 through 20, you list a number of factors that may extend a project's time in the queue as we mentioned earlier such as interdependency and developer-requested extensions. Are you familiar with all the factors you listed there?
A Generally, yes.
Q Thank you. And does Duke provide any sort of public report on those factors you list in your rebuttal testimony indicating that these delays occur and how long -- and for how long?
A I can't think where we'd provide a public report on the delays. Well, specifically the time of the delays, we've been I think fairly consistent and clear that these are some of they types of delays that we are experiencing that are beyond the control of Duke.
Q And do you --
A In fact, even in our proposed modifications we are asking for at least to include some timelines to potentially speed up the process of some or at least speed up some of these delays that we're experiencing.

Q And does Duke track those factors listed in your rebuttal testimony? For example, does Duke note when a project is paused after a developer requests an extension or files a dispute?

A I'll have to ask Witness Riggins to expand on my answer. But as we continue to invest in sales force and tools -- I mean, we're trying to do a better job of tracking details of the process. But it's been kind of a long process to get to the kind of detail that you're looking for.

A (Mr. Riggins) We have looked at the capability within sales force to track tolling, I think is the term that we would use. So during a time period when the project is out of our control, we're waiting on a response from someone, or we're waiting on some additional information, or decisions to be made, the project could be tolled during that time. So there is some capability within our sales force tool to do that. But I would also note that with the volumes of projects that we're managing today, it is difficult to track every day and every activity. So there is the capability and ultimately our goal would be to better track that so that we can monitor and to manage the projects more effectively, and the timelines that are in the procedures.

Q Thank you.

MS. BEATON: Well, Mr. Chairman, I know I asked for more time than this but I saw how much time everyone asked for and I streamlined my questions. So I have no further questions for the Duke panel.

CHAIRMAN FINLEY: We appreciate that very much. NCSEA.

MR. LEDFORD: Thank you, Mr. Chairman.

CROSS EXAMINATION BY MR. LEDFORD:

Q Mr. Freeman, I think I'm going to start were a few questions for you just as soon as you're ready.

A I'm ready.

Q On page 8 of your direct testimony, you point out that Section 6.1 of the North Carolina Interconnection Standard requires the utility to make reasonable efforts to comply with the timeframes of that with the standard. Are you aware that Section 6.1 goes on to say that if the utility cannot meet a deadline, it shall at its earliest opportunity notify the interconnection customer and explain the reason for the failure to meet the deadline, provide an estimated time by which it will complete the applicable procedure in the process?

A Yes, I'm aware of that -- you know, that communication, I'll call it a requirement. Yes.

Q So how does Duke go about notifying an interconnection customer about a delay?

A Well, this has been a kind of evolving process for us. We recognize that I guess early on in the process -- I think what were you're getting at is have we been diligent in notifying customers every single time we're experiencing a delay. I'm going to refer to Witness Riggins who can probably answer the question in more detail. But we are implementing a number of efficient or improvements. We've had internal stakeholder groups that are looking at how we can better communicate with customers when we do not meet those deadlines. So it's been an evolving, I'll call it, process improvement process that we've been going -- been pursuing, trying to get to where we are communicating every single time with every -- every time we meet -- or we miss a particular deadline.

I don't know if you want to add to that? (Speaking to Mr. Riggins)

A (Mr. Riggins) Yeah. I can expand on that. Last year, around 2017, we had a customer experience workshop that we conducted. I'm trying to talk to them and you at the same time. So one of the many things that we identified in that workshop in our attempts to be more transparent, more proactive; that's been one of the things that we've really been focused on is in order to be proactive you have to know when something is due or know when a decision needs to be made. So one of the other things we're doing within sales force is we're creating tasks or reminders for each project that tells us when something is going to be due so that the appropriate account manager or account specialist can take action on that proactively and hold us accountable and also hold our customers accountable for meeting those deadlines.

Q Thank you. And Section 6.1, in addition to notifying of the delay, requires the utility to explain the reason for the failure to meet the deadline. How does Duke go about accomplishing that?

A So the communications will be by email if there's a communication that's sent out notifying the customer of a delay. And included in that email should be some explanation as to what is generating the delay.

Q And also pursuant to Section 6.1, does that email include an estimate of when the applicable step will be completed?

A It will also include an estimate as to when we think the step will be completed, and it's based on our best reasonable guess at that point or estimate at that point.

Q And if the estimate is revised of when it will be completed, do you provide further communications to the interconnection customer?

A If we establish a new timeline and we don't hit that timeline, then again under reasonable efforts we would communicate again what the new deadline would be.

Q Thank you. Switching a little bit to staffing, Mr. Freeman, in your direct testimony you discuss the decrease in distribution level interconnection requests and an increase in transmission level interconnection requests. And then, Mr. Riggins, in your direct testimony you include a chart of Duke's staffing levels for interconnection. That's on page 12 of your direct testimony. Would you agree that the staffing levels for transmission level interconnection requests have not changed since 2015?

A (Mr. Freeman) Mr. Riggins can probably answer in more detail than me. I would not agree with that. We have added staffing to both the distribution and transmission to manage both transmission and distribution projects.

A (Mr. Riggins) Yeah, I would expand on that to say the transmission studies are conducted by our transmission planning team. So wherein most of the resources you see listed, those are dedicated resources. And in the transmission instance you see that I talk about FTEs, or full-time equivalents. So over that period of time it's our best estimate as to what was allocated. But I'm confident that they have the resources in place to study the projects that are presented to them.

Q So, Mr. Riggins, in Figure 1 of your direct testimony on page 12, the third to the bottom line, *transmission study planners*; would you agree that it says 7 under January 1, 2015, 7 under January 1, 2017, and 7 under September 1, 2018?

A I would agree.

Q And you're also saying that the staffing level has increased in that time?

A I didn't say it increased. These are the full-time equivalents that I believe have been allocated to do studies, and we continue to monitor the number of studies that we have, the workload and adjust the number of planning engineers actually conducting the studies at that time. So this number was based on my interaction with the planning team manager and trying to estimate how many resources could be allocated to those projects. As the volume increases, certainly the number of those people working more full-time on those studies increases.

A (Mr. Freeman) Well, let me clarify when I said that we have increased staffing, the Transmission Planning Group does use external consultants, and as I understand they're using them on a more regular basis. Also, that 7, I think represents the transmission planners involved in this. Within our organization we've continued to add staffing and some of that staffing is dedicated more to the transmission interconnection process than to the distribution process. I just wanted to clarify that I did not misrepresent when I said that we have added increased staffing. And also when you get to construction staffing, field engineers that do work, I mean, the study process does not take into account that at all. But as we're seeing an increase in the number of transmission projects interconnecting which you -- I would think you would recognize that we are seeing more and more transmission projects connecting up and are actually operating, it's taken a tremendous number of engineering resources, field engineer resources and construction resources to accommodate those projects.

Q Thank you, Mr. Freeman. Sticking with you but switching to your rebuttal testimony. On page 15 of your rebuttal testimony you discuss how as the

System Impact Study process has evolved, Duke has introduced various practices such as mitigation options, developer-requested extensions, cure periods, and informal information requests and challenges. Can you point me towards where in the redline of the Interconnection Standard that was included in the Duke and Public Staff Settlement Agreement the mitigation options and cure periods are incorporated into the language?

A I'm sorry. I was trying to get to the page you were referencing --

Q I'm sorry.

A -- and I was partly listening to your question and partly searching for where you were going to reference. So could you repeat your question?

Q Certainly. You discuss mitigation options and cure periods in your rebuttal testimony. Are those incorporated into the redline of the Interconnection Standard that's attached to the Duke/Public Staff Settlement Agreement?

A I'm not as familiar with all of the redlines that were included in the Interconnection Standards. I'm going to -- I'll refer the question to either Witness Gajda or Witness Riggins, but I believe we have asked for cure periods. I mean, we've been trying informally to use cure periods that when a particular project gets to a point where we've asked for information, for example, and we haven't gotten that information, we'll send kind of one last request for that information and we'll provide them with like, for example, another 10 days to respond and cure before we would either withdraw a project or whatever. So I think the answer is yes we are trying to formalize that process more than we have historically.

A (Mr. Riggins) I can speak to mitigation options a bit. Clearly, they're not in the Interconnection Procedures but they're part of the System Impact Study process that's taking place and were put in place I guess in response to some of the policies, some of the work we did around reliability and power quality, which is Mr. Gajda's area of expertise. So it was an effort to try to be accommodating and to find options that would allow interconnection of projects of certain sizes, hence the mitigation options, as opposed to just studying them at the size that was presented. In many cases the answer would have been that if they were to connect they would have to go to a transmission interconnection which would be much more costly. So we implemented those in response in an attempt to be more accommodating to the developers and to the customers.

Q And to be clear NCSEA supports the mitigation options and the cure period. But what recourse would an interconnection customer have if Duke were to stop offering mitigation options and cure periods given that they're not memorialized in the redline.

A (Mr. Freeman) I would think that would become potentially kind of a question for our legal support on what would be the appropriate process to go through looking at mitigation options. But -- I mean, we have been accommodating with those. I mean, if you look around the country, if you look at even the North Carolina Standards, I mean they're -- your interconnection request is studied. And the more we offer mitigation options the more it does impact other projects and it does kind of extend the process out. I think at this point it's fair to say that at least in the foreseeable future we do not have a plan to not offer the mitigation options. And again, I think it's an attempt to try and accommodate as many projects as we can.

A (Mr. Riggins) I would also add, though, that I think mitigation options and cure periods go hand-in-hand. Right. So we want to continue to offer mitigation options but there has to be an ability to put a deadline and to require a project to make a decision so that we can process through the queue. So I think it's important that we do both of those things.

Q Thank you.

MR. LEDFORD: Switching gears, Mr. Chairman, I'd like to pass out an exhibit. Mr. Chairman, I'd ask that the exhibit be marked as NCSEA Duke Cross Exhibit Number 1.

CHAIRMAN FINLEY: It shall be so marked.

(WHEREUPON, NCSEA Duke Cross Exhibit 1 is marked for identification.)

BY MR. LEDFORD:

Q Mr. Gajda, I believe these next questions are

going to be directed towards you.
A (Mr. Gajda) Very well.
Q Duke introduced its Circuit Stiffness Review in July of 2016; is that correct?
A I believe that's correct.
Q And duke applied the screen to all interconnection customers in the queue who had not yet signed an Interconnection Agreement; is that correct?
A That sounds correct.
Q And, in essence, under the July 2016 version of the Circuit Stiffness Review, if the stiffness at the point of interconnection of a generating facility was too low, the generating facility needed to reduce its capacity in order to interconnect; is that correct?
A That would be a mitigation option.
Q Were other options available?
A Well yes, I mean we're required to study the project at its level. So the implementation of an evaluation of stiffness ratio was a screen by which we realized that we had concerns for stiffness ratios below that number which means that then an advanced study, which we eventually

developed, needed to be formed in order to advance the interconnection at that size.

Q So prior to the creation of the advanced study what happened if a stiffness factor was too low?

A There was not an extensive period of time that went from the establishment of that. As you're probably well aware, there was a period of time in which we had to decide what that advanced study would be. We had -- we felt a sufficient number of evidence from events that occurred on the system to be concerned for low stiffness interconnections and we knew that the System Impact Study process and the studies that it described would not necessarily sufficiently capture all of the power quality reliability impacts that would occur for low stiffness interconnections so, therefore, we proceeded to developed that.

Q So that advanced study process that was developed, that was a part of the November 2016 CSR revisions; is that correct?

A That sounds correct.

Q And so in your opinion was the July 2016 version of Circuit Stiffness Review a Good Utility

Practice?

A I'll state that I believe everything we've done with Circuit Stiffness Review was Good Utility Practice. It has evolved and so that's -- I know you're referencing versions appropriately, and it has evolved through the process. I would reference it all as Good Utility Practice under the circumstances that we've been experiencing.

Q And how has the CSR screen evolved since the November 2016 revision?

A So it was a -- it began as I described just a minute ago. And again our -- we recognized the need to perform additional studies to properly capture the impacts for low stiffness interconnections so we set about doing that and part of that was done in conjunction with the industry, with the developer industry. We ended up creating that advanced study and began to implement that advanced study I -- if memory serves in early 2017. I believe we began to implement the advanced study and then as the advanced study was performed for those low stiffness interconnections we have proceeded since then doing that advanced study when the stiffness ratio was determined to be low. And, if the advanced study were to flag that, there will be a potential issue around, mostly around harmonics is what we're interested in, but then we would proceed to discuss with the developer ways to mitigate that issue.

The only further development that I immediately recall with Circuit Stiffness is that as we spent more time doing this advanced study, which to our knowledge was a type of study that had not yet been done across the entire utility industry because we were one of the first ones to discover some of the issues and concerns that we were finding, we evolved that kind of I would say one iteration further. And as we discovered that even some interconnections that were above this stiffness ratio of 25 could still potentially be of impact. And so we realized that really utility scale interconnections that had significant amounts of transformation, transformers at the site, would really -- needed to be evaluated for the impact of harmonics and rapid voltage change. And at that time since we had gotten a lot of practice doing those types of studies, it was a logical next step to assure that we didn't just stay kind of with our blinders on and stay with this original implementation and then risk having par quality impacts where we might miss them. So then we ultimately proceeded to doing those evaluations for most facilities over a megawatt I believe.

Q So how is the circuit stiffness ratio/Circuit Stiffness Review used today?

A So we proceed to calculate Circuit Stiffness Review -- excuse me, circuit stiffness ratio and -- because we've been calculating it and we believe that from a really long-term perspective it's a basic power system credo, that installing generators at stiff areas of the grid is much better than installing them in weak areas of the grid. So we proceed to calculate the stiffness ratio today and -- but we do not use it as a trigger for advanced study instead we use the trigger that I mentioned a minute ago.

Q Thank you. So just to be clear, it's your position that the July 2016 version of CSR, the November 2016 version of CSR, and the current version of CSR are all Good Utility Practice?

A That's correct.
Q Okay. Thank you. Mr. Gajda, you talked about power quality issues that prompted CSR.
A Yes.
Q Duke rolled after -- excuse me. After Duke rolled out the July 2016 version of CSR, the Company also entered into a Settlement Agreement with a number of solar developers; is that correct?
A That's correct.
Q And the Settlement was filed with the Commission which prompted the Commission to issue an Order requesting responses to questions; is that correct?
A That sounds correct.
Q Are you familiar with Duke's September 22, 2016, filing in response to those questions?
A I believe -- yes, I believe I know which one you're speaking of.
Q Subject to check, would you agree that Duke's filing discusses power quality impacts at a Campbell Soup facility that Duke attributes to a nearby solar facility?
A Yes, it does.

Q And that nearby solar facility was owned by Strata Solar?
A That's my understanding, yes.
Q And are you familiar with Strata Solar's filing in response to those same Commission questions?
A I'm not sure if I have immediate recollection on that.
Q Well, subject to check, would you agree that Strata's comments noted that the Circuit Stiffness Review would not have identified the issue that led to the power quality impacts?
A Subject -- I'm sorry. Repeat your question again. Subject to check --
Q Would you --

MR. JIRAK: If I could, if you'd like to question the witness on a document with which he's not familiar, I'd request that you provide a copy of the document to him.

MR. LEDFORD: May I approach?

CHAIRMAN FINLEY: Sure.

MR. JIRAK: If possible, we would like to see a copy as well so we can get some context for the questions.

MR. LEDFORD: Mr. Chairman, this is all in the record since the last revision. I only have my own copy.

MR. BREITSCHWERDT: Can we at least see it before the witness?

CHAIRMAN FINLEY: Go up and take a look and ask him the question. Counsel, go take a look at the paper that he's looking at. And, counsel, you ask the question.

(WHEREUPON, Mr. Breitschwerdt reviewed the document from the witness stand.)

MR. BREITSCHWERDT: Mr. Chairman, let the record reflect that these appear to be comments filed by Strata Solar in the docket on September 22, 2016, with some notes that Mr. Ledford has included, along with some highlighting.

CHAIRMAN FINLEY: I think that's what he identified. Let's get on with it.

BY MR. LEDFORD:

Q Would you agree that in those comments, and you can look at the areas that I highlit, that Strata Solar says the Circuit Stiffness Review would not have identified these problems?

A I see that statement you highlighted here.

Q Thank you. Subject to check, would you also agree that Duke's September 22, 2016 filing discusses power quality impacts at a Fidelity Bank that Duke had not resolved, but Duke had acquired a nearby solar facility owned by O2 emc to install power quality monitoring equipment?
A Yes, I recall -- I recall we had a potential report of a power quality issue and that -- and, yes, that's correct. We ended up -- there wasn't a resolution on that event.
Q And much like Strata Solar would you, subject to check, agree that O2 emc made a filing in response to the Commission's questions as well?
A Again, I don't track all filings so I'll have to take your word for that.
Q Well, subject to check, and it's also tabbed in orange there, would you agree that O2 emc said that the power quality issues at the bank existed prior to the construction of the solar facility?
A I see the statement.
Q Thank you. Would you also agree that the Public Staff's filing also in response to the same Commission questions noted that the Public Staff had not received any complaints related to power

quality?
A I'll take your word for that.
Q Thank you.

MR. LEDFORD: Mr. Chairman, at this time I would like to pass out another exhibit.

CHAIRMAN FINLEY: Go right ahead. I'll tell you what, let's take our afternoon break, Mr. Ledford, while you're passing that out. We'll come back at five minutes til 4:00, five minutes til 4:00. We're going to go to 5:30 this afternoon. 3:55.

(Recess began at 3:40 p.m., until 3:55 p.m.)

CHAIRMAN FINLEY: Let's come back on the record. Mr. Ledford.

MR. LEDFORD: Thank you, Mr. Chairman. Mr. Chairman, during the break I passed out an exhibit. I'd ask that it be marked as NCSEA Duke Cross Exhibit 2.

CHAIRMAN FINLEY: It shall be so marked.

MR. LEDFORD: Thank you.

(WHEREUPON, NCSEA Duke Cross Exhibit 2 is marked for identification.)

BY MR. LEDFORD:
Q Mr. Gajda, on page 50 of your direct testimony

you state that Duke's -- excuse me, you state that it is *the Companies' sole and complete accountability and responsibility for the safety, reliability, and power quality of the grid*. Is that an accurate reading?

MR. JIRAK: It's line 6.

A Thank you. Yes, I see it here. Yes, it is.

BY MR. LEDFORD:

Q All right. And turning to NCSEA Duke Cross Exhibit 2, would you mind turning to page 12230? I apologize for the weird numbering. But it's towards the back, a few pages from the back.

A I'm on that page.

Q And could you read for us the first full paragraph that begins with *several commenters expressed*?

A *Several commenters expressed their concern that some protection should be provided to qualifying facilities from potential harassment by utilities in the form of requiring unnecessary safety equipment. As discussed above, the State regulatory authorities with respect to electric utilities over which they have ratemaking authority and nonregulated electric utilities* *have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.*

Q Thank you. So in the case of the O2 emc Fidelity Bank issue that we discussed right before the break, the cause of those power quality concerns have not been resolved, but the QF wasn't required to install safety equipment; is that correct?

A The QF was required to install safety equipment as I recall as an overall part of the Settlement Agreement if I'm not incorrect.

Q But that was a part of the filing as well, the Duke filing, excuse me.

A Yeah, there were many power quality events listed. That was one of them but it was probably a small one but, yes, it was in there, but it was one of many.

Q So can you please explain to me how the QF being required to install safety equipment when the cause of the power quality issue had not been determined complies with FERC Order 69?

A The events that occurred -- the O2 facility in question I believe is a 20-megawatt facility. And there was no question once we dug into the Campbell Soup issue, which was also related to a 20-megawatt facility, that we really started to question at a higher level appropriate size of facilities and the range of potential impacts they could have on a system. So really from a more global perspective we realized that it was just from a utility perspective common sense and responsibility under our exercise of Good Utility Practice that necessitated the -- a requirement for power quality meters which, by the way a number of other utilities require power quality meters at interconnections. We really believe that to be an extremely responsible requirement for solar farms especially at that size.

Q Thank you. Let's stick with Good Utility Practice for a minute. And is it fair to say that in your direct testimony you state your disagreement with NCSEA's discussion of Commission oversight of Good Utility Practice?

A I'll probably have to go right to that in order to --

Q Page 55 if it helps.

A Page 55 of my direct testimony?
Q Correct, starting on line 10.
A Yes, I see the statement. Yes, I see a statement that the -- can I read the single sentence?
Q Yes.
A *Therefore, the Companies fundamentally disagree with NCSEA's contention that anyone other than the Companies, under the Commission's oversight, should have final decision-making power or veto rights over the determination of Good Utility Practice and the implementation of a proposed technical standard.*
Q And so in your opinion does the Commission have the authority to quote, veto Duke's determination of Good Utility Practice?
A Yeah, I don't -- yes, I don't -- the Commission's authority isn't under question, whether you call it a veto or a determination, but the Commission maintains authority here.
Q I believe "veto rights" was the phrase you used so I'm paraphrasing your words.
A Okay, very well.
Q According to NCSEA Duke Cross Exhibit 1 that was passed out a little while ago, Duke has

introduced nine new screens since May of 2015. Could you please explain to me the oversight that the Commission has had for each of these screens?

A Well, so I guess the way that I will attempt to answer your question is that it's our understanding that again the Commission has oversight, general oversight under the utilities' cost of service and quality of service and the Commission has established rules such as one that's -- one that I'm well familiar with is R8-17 under voltage delivered to customers. The Commission has established rules that are related to either cost or quality of service. The example I gave is quality of service, and so that the Commission's exercise of its authority has often been around the customer's direct experience. So when you ask about the Commission's authority with respect to, I think you mentioned nine different screens, these are -- these nine different screens you mentioned are essentially, what other term I can come up with them, are engineering guidelines by which we operate the system to assure -- operate and plan the system to assure that our customers still see that same voltage and whatever other direct customer experience requirements the Commission has put forth rules on.

Q So not to -- I'm not disputing Duke's obligation to maintain service quality but let's stick with those screens. How does Duke share information about those screens with potential interconnection customers?

A Yeah, so as we started seeing those large numbers of interconnections, it's I believe been well-established in testimony that we held a number of stakeholder meetings to share that information with the development community, and that was the -- really the only effective way that we knew at the time to do that and so we proceeded to do that on a number of occasions. More recently we were very interested in establishing a Technical Standards Review Group, and we believe that to be very likely the most effective method for sharing those types of -- that type of technical information and having those types of technical discussions going forward.

Q Thank you for that explanation, but I've got a couple of non-technical questions. Duke uses the location of line voltage regulators as an interconnection screen; is that correct?

A Yes, that's an item within our Method of Service Guidelines. Yes.

Q And how does Duke share information about the location of line voltage regulators with interconnection customers?

A Witness Riggins may or may not have immediate recollection on this. That I believe -- there is some information that is shared on that in a pre-application report I believe.

A (Mr. Riggins) Yeah, at a minimum the existing line voltage regulators are detailed in those reports and information we can provide. To some degree some of the planned regulators might not be defined because we don't know about them at that time, so we're asked to provide in pre-application the information that we know. But certainly we share that information as early as possible so that customers can make a good decision based on that.

Q So I want to keep with as early as possible if we could. So per the redline that's attached to the

Settlement between Duke and the Public Staff, if approved by the Commission the fee to obtain a pre-application report would be $500; is that correct?

A That's correct.

Q And Duke does not make the location of line voltage regulators available publicly, correct?

A That's correct.

Q And why is that?

A I'm not sure it's meaningful information to the general public. There's lots of information about reclosures and regulators and other pieces of equipment that's not published for the public to see.

Q Would you agree it's meaningful to a potential interconnection customer if they had that information before they had to pay $500?

A I suppose it's meaningful but I think a $500 pre-application which is made available under these interconnection procedures is a reasonable amount of money to pay for the information, line voltage regulators or otherwise, that might help a customer make a good business decision about whether it's a viable request.

A (Mr. Gajda) If you'll permit me, I think overall from providing this information prospectively ahead of time Duke does have a significant number of concerns about just putting mass data about the grid, even the distribution grid, and making it widely and publicly available. So I think that's just another item to keep in mind.

Q So are line voltage regulators protected by fencing or any security measures?

A (Mr. Riggins) Typically they're installed on a pole or a couple of poles.

Q And are they hidden from the public in any way?

A They're not hidden.

MR. LEDFORD: Mr. Chairman, if I could.

(WHEREUPON, Mr. Ledford passed out an exhibit.)

MR. LEDFORD: Mr. Chairman, I'd ask that this exhibit be marked as NCSEA Duke Cross Exhibit 3.

CHAIRMAN FINLEY: It shall be so marked.

(WHEREUPON, NCSEA Duke Cross Exhibit 3 is marked for identification.)

BY MR. LEDFORD:

Q Is this image in Exhibit 3 a line voltage

regulator?
A (Mr. Riggins) Yes.
Q And would -- subject to check, notably in the left-hand corner, would you agree or accept that this line voltage regulator is near the corner of Wade Avenue and Dixie Trail here in Raleigh?
A (Mr. Gajda) I'll agree that it is because I drive past it every day.
(Laughter)
Q That was actually one of my next questions because I drive past it every day as well.
So an interconnection customer could walk Duke's lines and find every single one of these; is that fair?
A (Mr. Riggins) That's correct.
Q But that would be an extremely time consuming activity, correct?
A (Mr. Freeman) Define extreme time consuming activity because I think -- I mean what we've seen is all of these developers installing these larger facilities are all sophisticated developers and they've got engineers that can identify these fairly rapidly. So I'm not sure exactly what you mean by time consuming.

Q Wouldn't it be more rapidly -- wouldn't they be able to identify them more rapidly if Duke made the information publicly available?

A Sure. But then you're asking Duke to spend time and money to identify these locations as well, and then there's a question about who and how should those costs be recovered.

Q Does Duke not have the information readily available about the location of its assets on the grid?

A I would think it's fairly readily available because we make it readily available in the pre-application report.

A (Mr. Riggins) Correct. So, again it goes back I think to the debate of do you make all information available to all people at some cost that might be significant versus following the processes that are in the Interconnection Procedure today and are providing the information to customers that have a need for it and have them pay for that service.

Q Okay. So we've discussed the various screens that Duke has put into place since May 2015. I want to switch gears to future new screens that might be coming.

Mr. Gajda, in your rebuttal testimony on page 25, you state that *the Companies' agree to file any significant new screens, studies, or major modification in their application of the procedures with the Commission for informational purposes only*. Is that an accurate reading?

A (Mr. Gajda) Yes, it is.

Q What makes a new screen significant?

A Well, that's a great question. And it's kind of the crux of many things interconnection is what we don't know yet is what we don't know yet. So not to be coy but literally as we proceed forward and learn new things about how interconnections continue to impact the grid we have no -- there's really no reason or we're not incentivized to create any new screens and so to the degree that anything would be needed we would set about a process that I believe we've described in testimony or data requests to consider modifications to Good Utility Practice and determine whether something else would be needed. I really don't have a great solid answer to describe what's significant or insignificant. There's really not a way to do that.

Q Could you tell me --

A (Mr. Freeman) But I would --

Q Oh, sorry.

A I would also suggest that what Mr. Gajda has said earlier is that we're using the TSRG process to discuss new screens and I would think that through discussions there and feedback from developers that may see that a particular new screen or new policy would have a, I'll call it a significant impact. That discussion would probably drive what would be deemed as significant.

Q Let's stick with the TSRG for a minute. Mr. Gajda, in your direct testimony on page 29, you state that Duke is willing to discuss the Fast Track process at the Technical Standards Review Group or TSRG; is that correct?

A (Mr. Gajda) Yes.

Q And of the intervenors to this proceeding, who has advocated the strongest for reforming the Fast Track process?

A That's a bit of a subjective question.

Q Would you agree that IREC has taken the lead on that issue?

A That's likely fair.

Q And is IREC invited to participate in the TSRG?

A Not -- no, not specifically and there's a reason for that. It's because we structured the TSRG. When we began its structure we looked out in the industry to see how other TSRGs, if they were named so, were structured. We specifically visited the Massachusetts TSRG which there has been mandated by the Commission, and I only say that because there's four utilities at the table, but as we went there we realized that there were utilities at the table and there were individual project developers, engineers at the table, and so our conception of the TSRG from the beginning was that it was a highly technical forum and it should involve engineers and -- that were likely developing projects for their consultants. And our -- we went to NCSEA, NCCEBA and South Carolina Solar Business Alliance with the intent of trying to seek out those appropriate parties. And so this is just really a reminder for everybody what we did there but -- so I understand your question and your point but ultimately that was what we did because we believed that the -- who's sitting down at the table and physically designing projects is who needed to be at the TSRG.

Q So in your direct testimony you state that the Companies established the TSRG in conjunction with NCSEA. How did NCSEA assist in establishing the TSRG?

A Again, we went to NCSEA, NCCEBA and South Carolina Solar Business Alliance to really seek input on membership and who should be at the table. Because of the solar development community or for that matter any distributed generation entity because there's not any one single representative, it wasn't like we were going to another utility. In this case, we had to really kind cast a wide net. And as advocacy organizations we thought that it was fair to go to NCSEA and the two others mentioned to seek that and that's why we proceeded in that manner.

Q So you just said that, and I'm paraphrasing here, that you came to NCSEA seeking guidance on who could have a seat at the table. What was NCSEA's role in selecting the organizations that participated in the TSRG, or that participate in the TSRG?

A Well, as I recall, subject to check - since I get to say that now - as I recall, I believe that we essentially requested, we had a concept for how the TSRG would be laid out and with, I believe we called it, three kind of primary members and six sort of secondary members with the intent that the primary members would be involved in agenda development in conjunction with Duke. And as I recall, we went to the organizations essentially just seeking membership. There may be a portion of this that I'm not recalling properly and, if so I apologize, but that's my recollection.

Q So is it fair to say that NCSEA simply agreed to attend the TSRGs as opposed to developed it in conjunction with Duke?

A Yes. I mean to be quite honest, yeah, Duke knew that a TSRG process would be valuable. We had been asked by several external parties if we were considering something like that, so we went about to create it and in that process, that's correct, we approached NCSEA and the two other organizations for membership.

Q Thank you.

Mr. Riggins, switching to your rebuttal testimony, on page 19 you state that *the Companies commit to share with the Public Staff the current plans for the online portal and to identify additional features that need to be evaluated*; is that correct?

A (Mr. Riggins) That's correct, yes.

Q Why would the Company only share this information with the Public Staff?

A (Mr. Riggins) I'm not sure I'm following the question. Who else are you suggesting they would share it with?

Q Would the Company be willing to share it with other stakeholders such as intervenors to the current proceeding?

A Certainly. I think we actually have reached out to a number of stakeholders and developers to get input. And particularly around the customer portal there's been engagement already with those parties to try to make sure we're designing something that would be applicable and be of value.

Q Would the Company be willing to file their plans with the Commission?
A I think if asked to do that there would be no reason why we wouldn't file it.
Q Thank you.
Mr. Gajda, returning to you for a few more.
A (Mr. Gajda) Yes, sir.
Q I want to talk about material modification for just a little bit.
A Okay.
Q In your direct testimony you discuss Duke's proposal to use the date of the execution of a System Impact Study Agreement as the determining point of fact for when a study has been start -- for when a study has or has not started; is that correct?
A That sounds right.
Q And that same language is incorporated into the redline of the Interconnection Standard that was attached to the Duke/Public Staff Settlement Agreement; is that correct?
A I believe that's correct.
Q But the execution of an SIS Agreement does not

necessarily mean that Duke can immediately be in the study; is that correct?

A Perhaps and it's the only reasonable external checkpoint which clearly defines between Duke and an external party when, essentially when we will begin the study.

Q What's the average time between the execution of an SIS Agreement and the actual start of study by the utility?

A I don't have that piece of information.

A (Mr. Riggins) I can weigh in. I don't have a specific number of days but I can tell you that we do start the study pretty soon after the study -- the System Impact Study Agreement is signed because now we intentionally provide that Agreement to the customer when we're prepared to start the study. So in delivering the Agreement that indicates that we're now prepared, that customer is now a Project A or a B, and it's ready for study. So the start of the study should be very coincident with when that Agreement is signed and returned.

Q Thank you. Do you have any idea of how many interconnection customers currently in the queue

have executed an SIS Agreement but Duke has not yet started the study?
A I don't know that number specifically.
Q Thank you. Switching gears a little bit to how Duke plans.
Mr. Freeman, in both your direct testimony and your rebuttal testimony you discuss about $200 million in transmission network upgrades that are necessary to interconnect additional generations -- additional generation in portions of eastern North Carolina; is that correct?
A (Mr. Freeman) That is correct.
Q And in your direct testimony discuss that heavy saturation of Duke's distribution system with solar may require a massive redesign of Duke's distribution system; is that correct?
A That is correct, yes.
Q Are you familiar with Exhibit PB-2 which was attached to NCSEA Witness Brucke's initial testimony?
A No, I'm not.
Q Subject to check, would you agree that it is a PowerPoint presentation that explains Duke's Grid

Improvement Plan that was distributed by Duke in November?
A Okay, subject to check.
Q Are you aware whether this massive redesign of the distribution system appears in Duke's Grid Improvement Plan?
A Subject to check, because I'm not specifically referencing your document. But, no, I don't think that is part of the Grid Improvement Plan.
Q Thank you. And the transmission upgrades in eastern North Carolina, are they a part of the Grid Improvement Plan?
A No, they are not. Those are triggered specifically by interconnection requests and the studies that were done to interconnect those facilities. So those upgrades are tied directly to interconnection requests and interconnection -- or interconnecting generators.
Q Thank you. And, Mr. Freeman, or any of you, are you familiar with the North Carolina Transmission Planning Collaborative?
A Generally I think we're all familiar with it, yes.
Q Are you familiar with the Collaborative's most

recent report?
A I am not, no.
A (Mr. Riggins) No.
MR. LEDFORD: Mr. Chairman, may I pass out an exhibit?
CHAIRMAN FINLEY: Yes.
MR. LEDFORD: Mr. Chairman, I'd ask that this exhibit be marked NCSEA Duke Cross Exhibit 4.
CHAIRMAN FINLEY: The report shall be marked as Number 4.
MR. LEDFORD: Thank you.
(WHEREUPON, NCSEA Duke Cross Exhibit 4 is marked for identification.)
BY MR. LEDFORD:
Q Mr. Freeman, are you aware of where any of the reconductoring projects that you discuss appear in the Collaborative's report?
A (Mr. Freeman) I am not aware, no.
Q And recognizing that I just dropped a 100ish page document in front of you, subject to check, would you agree with me that they do not appear anywhere in there?
A Sure I'll agree with you. Yes.

Q Thank you. Mr. Freeman, in your direct testimony and your rebuttal testimony you extensively discuss the concept of cluster studies, just specifically stating that the Company now believes it's time -- excuse me, the Companies believe that it is now necessary to transition from a serial study process to a cluster study process; is that correct?
A That is correct.
Q Did NCSEA raise the issue of cluster studies at the beginning of the 2017 stakeholder process?
A I don't recall.

MR. LEDFORD: Mr. Chairman.

(WHEREUPON, Mr. Ledford passed out an exhibit.)

CHAIRMAN FINLEY: We'll mark this exhibit Number 5.

MR. LEDFORD: Thank you, Mr. Chairman.

(WHEREUPON, NCSEA Duke Cross Exhibit 5 is marked for identification.)

BY MR. LEDFORD:
Q Mr. Freeman, would you agree this is a list of issues that NCSEA presented at the initial

stakeholder group meeting on May 25, 2017?
A I don't believe I was at that meeting but it looks like this is -- I mean I'll take your word for it that this is what you prepared and -- for discussion at that meeting.
Q Mr. Gajda or Mr. Riggins, were either of you at that meeting? It has been awhile; I can't recall.
A (Mr. Riggins) I attended several, but I don't know about this one specifically.
A (Mr. Gajda) Likewise.
Q Subject to check, would you agree that Advanced Energy did a pretty good job of distributing materials that were handed out at meetings to participants whether they were in physical participation or not?
A (Mr. Freeman) I'll let my peers answer that question because I only attended maybe one of those particular stakeholder meetings.
A (Mr. Riggins) Can you restate the question?
Q Did Advance Energy -- I'll retract the question.
Looking slightly more than half way down the page, would you agree that under the bullet point *Are structural changes to the*

interconnection queue necessary? NCSEA posited the question, *should cluster studies be adopted*?
A (Mr. Freeman) What I read you're correct.
Q Thank you. But at that time Duke did not support discussing cluster studies during the stakeholder process; is that correct?
A I -- again, I only attended one meeting so I don't know what kind of discussions took place during those stakeholder discussions. But I think the intent of that particular stakeholder group was driven by the 2015 Interconnection Order where two years later we were being asked to look at any particular changes to the Interconnection Procedures as they were written at that point. So I think at that point in time we were looking at kind of minor modifications that needed to be -- that needed to take place based on the two years of history that we had since we revised the Interconnection Standards in 2015.
Q Thinking back to the 2014 proceeding, weren't cluster studies raised at that time?
A Yes, they were. Yes.
Q So it would be logical for NCSEA to raise them

again in the stakeholder meeting that followed the 2015 Order?

A Yeah. I would grant that that would be logical, yes. But during the 2014 discussions -- you know, the discussions around cluster studies we just didn't feel like that it was appropriate at that time to initiate cluster studies, and we felt like at that point in time that the sequential study process was adequate. In fact, at that point in time we had I think either zero or almost no transmission projects in the queue and at that time we weren't experiencing any kind of transmission congestion. And I think even in at least one of our testimonies we described that looking at the distribution system as a radial system that cluster studies really are not that appropriate for distribution but yet they are more appropriate for transmission in the transmission network.

Q But that conversation was never had during the 2017 stakeholder process, correct?

A I can't answer that.

Q Okay. Why should stakeholders believe that the outcome -- excuse me. Per paragraph three of the

Settlement between Duke and the Public Staff, Duke is now committing to a new stakeholder process to discuss cluster studies, correct?

A That is correct.

Q So why should stakeholders believe that the outcome of a new stakeholder process would be any different than the outcome of the 2017 one?

A Well again, I think since twenty -- the 2014-2015 timeframe with the amount of projects that are in the queue I think our thinking has changed and we feel like it is appropriate. In fact, when we looked around the country now, a number of utilities and RTOs that are experiencing the same heavy penetration that we're experiencing have all either moved towards cluster studies or are in the process of moving towards them. So, for example, I think we identified in our testimony that Public Service Company of Colorado is in the middle of potentially converting from sequential study process to cluster studies. In fact, they filed with FERC and we're hoping to see what kind of results -- you know, whether FERC approves their cluster study change or not. So, for example, PSCO or Public Service of Colorado, they have as I recall 23,000 megawatts of projects in their interconnection queue and they're only an 8500 megawatt system. So I think most utilities are starting to see that -- you know, what we've historically done around sequential study process is just not sustainable and that we need to really look at a fundamental change in how we're studying projects.

Q Mr. Gajda, in your direct testimony on page 7, beginning on line 3, you state that *Overall, the Companies see limited structural issues within the technical evaluation portions of the North Carolina Procedures, and do not believe that extensive revisions are necessary at this time*. How does that statement -- does that statement contradict what Witness Freeman has testified in his direct and rebuttal testimony?

A (Mr. Gajda) No, it does not. As Witness Freeman stated, when we approached the 2017 stakeholder process it was really in response to the Commission Order to do so. And so I believe for the most part Duke approached that relatively open minded with the idea of there are several stakeholders in this process and let's sit down and see what minimum number of changes may produce value in the Interconnection Standards knowing what we know today. I believe Witness Freeman's statements around the need for cluster studies really developed sometime after this process began.

Q Thank you. Switching gears, Mr. Gajda, on page 63 of your direct testimony you discuss physical limitations to balancing area's capability to absorb energy injections. Would a larger balancing area make this better?

A That's a very complicated question. Not necessarily; could, could not. But that's a very complicated question.

Q We're lucky I don't have any follow-ups on that.

(Laughter)

Q Just one question about dispute resolution. In the Settlement redline Section 6.2.4, it states that by mutual agreement the utility and the interconnection customer may seek the assistance of a dispute resolution service. When would it be in the utility's best interest to engage an outside mediator or dispute resolution service?

A (Mr. Riggins) When would it be in the utility's best interest?

Q Or when would the utility agree to that?

A I think that we stated that we would support engaging a third party, but we also strongly believe that the Public Staff has served in that role and we've been able to resolve most of the disputes that have been brought forward in an efficient manner. We still believe that to educate a third party on all of the issues is going to be difficult, time consuming, distract people that are otherwise working on interconnection projects to bring them up to speed. So when would we support it? I suppose if we got to a volume that made it such that the Public Staff couldn't handle the volume we would certainly support that. But our position today is that we would prefer to continue to work as we have and effectively addressing disputes efficiently.

A (Mr. Freeman) And I'll suggest that -- I mean, this is another example of kind of moving into a living lab. I mean, we've committed at the developer's request. Or even the Public Staff suggested this that I think we're all going to learn what's -- kind of what's the appropriate trigger for moving to a third party, mediator, or whatever you want to call it so I think that's yet to be determined. But I think that we've -- the Companies' have made a commitment that we're willing to engage that third party when it's appropriate.

MR. LEDFORD: Thank you. I have no further questions.

CHAIRMAN FINLEY: NCCEBA.

MS. KEMERAIT: I have questions for Mr. Riggins and Mr. Gajda but I don't believe I'm going to have any questions for Mr. Freeman.

Mr. Riggins, I'll begin with you.

CROSS EXAMINATION BY MS. KEMERAIT:

Q I've got a number of questions about payment for interconnection facilities and I'd like to begin by asking you to provide some information about the differences between what upgrades are and what interconnection facilities are. And to begin with, are you familiar with the definitions that are contained in the Glossary of Terms of the North Carolina Interconnection Procedures?

A (Mr. Riggins) Yes.

Q So in order to save a little bit of time what I would propose I would do is I will just read you the definition and then you can state whether that is your understanding that that is, in fact, the correct definition contained in the Glossary of Terms.

And the definition of "Upgrades" as stated in the Interconnection Procedures is the required additions and modifications to the Utility's system at or beyond the Point of Inter- -- excuse me, at or beyond the Point of Interconnection. And Upgrades may be network upgrades or distribution upgrades. And it also states that Upgrades do not include Interconnection Facilities. Is that your understanding of the definition of Upgrades?

A That's correct.

Q And so is it -- would you agree that upgrades are considered to be those types of improvements to a utility's system that allow the interconnection facility to deliver output to the system in a safe and reliable manner?

A I believe upgrades are -- those facilities -- those upgrades that we do to the system that are not dedicated and on the specific property for the interconnection, but to make sure that that interconnection doesn't negatively benefit other customers -- negatively impact other customers.

Q And so in contrast to that is interconnection facilities that would be dedicated to a specific interconnection customer and on that interconnection customer's property; is that correct?

A That's generally correct.

Q Okay. And the definition - and I'll read this as well - for "Interconnection Facilities" contained in the Glossary of Terms states that, Collectively, the Utility's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Utility's system. The Interconnection Facilities are sole use facilities and do not include

Upgrades. Would you agree that that's the definition for Interconnection Facilities?

A Yes.

Q And the definition for Interconnection Facilities talks about sole use facilities. And could you describe what is meant by "sole use facilities"?

A Essentially a sole use facility is a facility that doesn't benefit other customers. So it's there -- if not for that interconnection customer that facility would not be there.

Q So, in other words, it would be specific to the interconnection customer that is seeking to interconnect?

A That's correct.

Q And would any other interconnection customer be dependent upon another interconnection customers' interconnection facilities if the interconnection facility was not constructed or installed?

A They should not.

Q And so if a --

A (Mr. Freeman) Can I clarify that answer? I want to suggest, maybe I'm hearing the question wrong, but what I'm hearing you saying is that if that interconnection facility was not constructed. I think the only reason it would not be constructed would be because the interconnection facility either withdrew or canceled their project. Yet, I would suggest that in the sequential process that we use there are interconnection facilities that are behind that facility that potentially are impacted by that facility not being built. And again, I'm assuming that it's not going to -- if it's not built it's because the facility is canceled. So I think there is a direct relationship to other projects.

Q And, Mr. Freeman, can you describe if the -- so if the interconnection request is withdrawn before construction of the interconnection facility has begun - any type of construction, or installation, or any work done on the interconnection facility - in what way would interconnection customers that would be farther back in the queue be in any way prejudiced?

A I think this relates to -- you know that particular facility has, I'll call it consumed or consumed -- what I call grid capacity, so that does impact other facilities that are further down in the queue.

Q And what do you mean by grid capacity?
A Well, there's a -- when I think about grid capacity I think about -- you know, there's only a certain amount of capacity on the existing grid to accommodate a particular generator, so that's what I mean by grid capacity. And if we need to upgrade the capacity it's -- I mean, that's generally what an upgrade does is it increases that grid capacity.
Q And so the -- but the interconnection facility though would in no way -- if it's not constructed though it is not going to take up any of the grid capacity, correct?
A Well, it -- maybe to your point it doesn't negatively impact that next project but it potentially does because if that particular project did not trigger upgrades and then the next project behind it did trigger upgrades, one project not being constructed potentially changes the solution, if you will, for the next project or vice versa. That particular project in another example may have triggered network upgrades or upgrades and then those upgrades would be passed onto the next project. That's

what I mean.

Q That's really a question about responsibility for network upgrades, correct?

A Yes. I mean, it's -- when I say grid capacity I mean that project moving forward or not moving forward does have an impact on future projects both positively or negatively.

Q Well, I don't want to belabor the point, but not moving forward, the failure to construct an interconnection facilities is not going to affect whether network upgrades are assigned to an interconnection customer that's further back in the queue, that would be based upon an interconnection customer withdrawing its interconnection request and not moving forward?

A (Mr. Riggins) I think it's a question of specific interconnection facilities. Those should be distinct and shouldn't have a negative impact. Certainly a withdrawal can impact a later queued project from a capacity standpoint and upgrade, but the facilities installed at the property should not have a negative impact.

Q Thank you, Mr. Riggins. And now I'd like to move on from that line of questioning to about payment

for interconnection facilities. And, Mr. Riggins, that is addressed -- is it your understanding that that is addressed in Article 6 of the Interconnection Agreement and then also the milestones that would be included in Appendix 4 of the Interconnection Agreement?
A Yes.
Q And currently Section 6.1.1 of the Interconnection Agreement requires that the interconnection customer is responsible for paying 100 percent of the required interconnection facilities and then other charges as required in Appendix 2; is that correct?
A That's correct.
Q And those payments are required to be provided by the interconnection customer pursuant to the milestones that are specified in Appendix 4; is that correct?
A We typically include the payment as a milestone in Appendix 4, but it is a prepayment of those interconnection facilities' charges.
Q And for the prepayment of the interconnection charges, and again that was going to be some other questions that involve -- considered to be

prepayment by the interconnection customer, correct?

A It's a little bit complex, as John said on the other question. So I'll --

Q And I'll come up to those questions and I do realize it's a little bit different in DEP and DEC territory.

A So can I just clarify that interconnection facilities are generally paid for under the extra facilities methodology which is part of our service regulations and they do differ from DEC and DEP. And some cases in DEP there's a contributory plan that would require the prepayment of that up-front amount. In DEC, the extra facilities, typically customers choose the monthly payment, so those payments do not start until the facility is built and billing begins. So, at most, there would be a deposit to be sure that we get to that point so that that monthly fee would begin.

Q And it's my understanding that in both DEC and DEP that for transmission projects -- interconnection facilities for transmission projects that both DEC and DEP require up-front

payments; is that correct?
A Again, in DEP if a customer chooses the contributory plan to pay for their interconnection facilities, they would prepay the cost of that interconnection facility and an ongoing monthly fee. In DEC, unless a customer chooses a prepayment option which most do not, they begin to pay a monthly fee at the time the billing starts which is when the project is constructed. So for transmission, because the magnitude of those projects is typically higher, we will require a deposit for that as allowed in the Procedures to require reasonable security.
Q And for those prepayments upon COD, are any of those prepayments reimbursed to the interconnection customer?
A So we wouldn't have a prepayment at COD, that would be at the end of the project.
Q Right.
A So to the extent that a prepayment is required at the beginning of the project, if that project is terminated then essentially that amount less cost incurred would be refunded.
Q Thank you.

A For interconnection facilities.
Q Yes, correct. And I'll clarify that what I'm -- all of my questions are related to interconnection facilities and not network upgrades.
A Okay.
Q And going back to my question about the payment and the milestones that would be provided in Appendix 4. If there is a prepayment, what does the -- what does Duke require for the number of days after an Interconnection Agreement is executed when that prepayment must be made? Is it 60 days after execution of the Interconnection Agreement?
A It's different between North and South Carolina so I'll have to look through the procedures to be sure I get the right number of days, but it is a specific timeframe by which the interconnection customer has to pay the fees.
Q Okay. And if the interconnection customer does not provide the payment that is required under the milestones in the Interconnection Agreement, what can occur? Can -- Duke can terminate the Interconnection Agreement; is that correct?

A Yeah, according to the North Carolina Interconnection Procedures that's what we're required to do.

Q Correct. And so I'm going to move on to some questions about the timeframe generally that it takes to construct interconnection facilities. And does it take different, generally different periods of time in DEC and DEP territory to construct interconnection facilities for transmission interconnections?

A Not significantly different, no.

Q And what is the general amount of time that it takes to construct those interconnection facilities for transmission interconnections?

A Typically about 24 months.

Q And for transmission interconnections the construction of the interconnection facilities can be delayed due to network upgrades that might also have to be constructed; is that correct?

A That's possible.

Q And is it possible based upon some filings that Duke had made back in the earlier phase of the interconnection docket, Duke had stated that it could take sometimes three to five years for the network upgrades to be completed so that the interconnection facilities would be delayed for three to five years; is that correct?

A If an interconnection customer is dependent on an upgrade assigned to another customer they should not get to an Interconnection Agreement and be forced to make that payment. If they're -- they may have received an interim study, but I don't believe they should have an Interconnection Agreement and be required to make that payment.

Q For the interconnection facilities?

A Correct. In particular, we've looked at some of these projects that are going to have to wait for an upgrade. It might take three to four years. We know that the costs that we would put into the Interconnection Agreement today would be somewhat stale in four years when we are ready to build those facilities so we'll intentionally want to delay that process and enter into an IA at the time that's more appropriate.

Q So in this case, the IA would be delayed is your testimony?

A That's correct. We would not deliver the Interconnection Agreement. We should not deliver

the Interconnection Agreement to the customer until we're prepared to build those facilities.
Q And then for interconnection facilities for interconnection to the distribution system is the time to construct those facilities different in DEC and DEP territory or is it substantially the same?
A The time to build the interconnection facilities should be very similar.
Q And what would that be in for both DEC and DEP territory?
A I don't know an exact number but my best estimate would be you're talking a period of months, not 24 months, but we're talking about availability of crews and the ability to get the work scheduled, and if there are no upgrades that are required it's a fairly quick process just to build the interconnection facilities themselves.
Q And for upgrades you mean network upgrades?
A No, I'm speaking of distribution system upgrades such as reconductoring, that sort of work that can take longer periods of time.
Q And those distribution system upgrades could take 12 to 15 months; is that a good estimate about

the timeframe that it might take?

A It depends on the degree of work that's required.

Q And, generally, how long -- what would be the outermost time that it would take to perform those distribution system upgrades?

A Fifteen months might be an estimate of worst case scenario. If there's substation upgrades that have to be done as well as distribution line upgrades, then certainly those can take a little longer.

Q And will the construction of the distribution interconnection facilities, will that be -- will that construction wait until the distribution system upgrades has been completed?

A I don't think that's a fair statement. We would try to align the work on the interconnection facility with when the project is built and when the upgrades are done. But I don't know that it's absolutely scheduled that way to always occur after the upgrade is done.

Q If it takes place around the same amount of time it could be, as you mentioned, about a 15-month waiting period before completion of the interconnection facilities. Is that a fair statement?

A I think that's a reasonable estimate of an outlier. If a project requires substation upgrades - additional equipment to be installed in the substation, significant reconductoring work of the distribution facility - then it can take some time.

Q And can you describe what the general cost for both transmission connected interconnection facilities and distribution connected interconnection facilities is?

A I'd say order of magnitude distribution facilities are probably eighty to a hundred thousand dollars; transmission interconnection facilities to three to five million.

Q And, Mr. Riggins, are you -- well, I should say I assume you're aware that NCCEBA and a number of interconnection customers have been raising the issue about concerns about having to make payments, prepayments for interconnection facilities well in advance of when the funds are needed by Duke, and then also about the request that a surety bond be permitted as an acceptable form of financial security by Duke. I assume

you're familiar with those requests?
A I am.
Q And currently what type of financial security does Duke allow for interconnection facilities?
A I don't know the specifics on that. Anything other than cash, of course, would be presented to our credit and risk department to assess that to make a determination if it's acceptable or not.
Q And does Duke allow a cash collateralized letter of credit as financial security currently?
A I can't answer that.
Q But currently Duke does not allow a surety bond as an acceptable form of financial security?
A I think we've already agreed in certain circumstances where the need for network upgrades are going to be over an extended period of time that we would consider surety bonds in those particular instances.
Q And so I think that one of the concerns for NCCEBA and the interconnection customers is when they provide prepayment or the cash collateralized letter of credit after the Interconnection Agreement has been executed that there could be a significant period of time in

which the money is being held by Duke and they're not able to earn any interest on it and it's been provided to Duke. Is that -- has that concern been expressed to you?

A Certainly we've heard that concern. But I would also point out that there's not necessarily a long delay in when a project starts. So when Duke gets paid there is additional design work, there's procurement work, sometimes there's the commitment to resources that has to be made in advance. So I would say that when the Interconnection Agreement is signed and we receive that payment we go to work on all of those activities. It just sometimes can take a period of months before the end result is reached.

Q And those costs for the interconnection facilities, you mentioned design work, and then I assume also the construction and installation work. What are some of the other major components of the cost for the interconnection facilities in addition to those three?

A Well, I think those are the major components - design, engineering, procurement, and then constructing the facilities.

Q And with the design portion of the cost, would that be considered to be the least amount of the cost for the interconnection facilities?

A I think that's safe.

Q And is it fair to state that sometimes Duke begins the design portion of the interconnection facilities and then there could be some substantial delay before any further work for the, for example, the construction or installation of the interconnection facilities has begun?

A I don't know of specific instances where that's happened, but I can think of an example where design work might begin. And then one of the other things I didn't mention which is not necessarily a cost item, but sometimes we have to secure additional rights-of-way or easement in order to build the upgrades that might be necessary or to extend a line to a project. So it might make -- there may be certain situations where that work is going on and there might be some delay in some of the construction.

Q Thank you. And then, Mr. Riggins, in your

rebuttal testimony duke has stated through you that Duke will allow surety bonds as an acceptable form of financial security when there is what's been described as a material lag between the execution of the Interconnection Agreement and the date when Duke begins spending money on interconnection facilities. Is that a correct statement?
A That's correct.
Q And can you describe what a "material lag" means?
A I think in that statement what we're envisioning is this upgrade that we're all faced right now, so probably a three to five-year time period would be considered significant.
Q So it would be -- it would not be a time period that would be less than three to five years to constitute a material lag to your understanding?
A To my understanding.
Q Okay. And finally, Mr. Riggins, when it can be many months to several years after the prepayment is required before the interconnection facility construction begins, is there a reason that the interconnection customer needs to post cash or financial security 60 days after the

Interconnection Agreement is executed when Duke does not begin spending money for a significant period of time afterwards?

A Well, first and foremost I think it's required under the Procedures. And then secondly, again I mentioned in DEC where the interconnection facilities typically are paid for as a monthly fee at the end of the project when it's constructed, so I don't think you have the issue there. And, in DEP, again if they choose the contributory plan under extra facilities there is an upfront prepayment that's required. There's also the option of the noncontributory plan which looks more like DEC. It's a higher monthly fee but it would not require an upfront payment of those fees.

Q And there could be a scenario that would be possible in which -- so Duke is not going to begin spending money on interconnection facilities until it has payment from the interconnection customer; is that correct?

A That's correct.

Q So there could be a scenario that would be a fair situation in which for those prepayments Duke could invoice the interconnection customer in advance of when it begins, when it needs to begin spending any money on the interconnection facilities, and then would provide a specific period of time - 30 days, 60 days - in which that 100 percent payment would be required to be made. That could be a possibility as well?

A I don't think that's a possibility under the procedures as they exist today because it requires payment to be made in the timeframe you mentioned.

Q And are you aware through your counsel that that is a request that NCCEBA is currently making of Duke at this point to try to see if we can work out that issue after the hearing?

A It's my understanding there's been conversation.

MS. KEMERAIT: Thank you. I have no further questions.

CHAIRMAN FINLEY: Attorney General.

MS. KEMERAIT: And I have a few questions for Mr. Gajda as well.

CHAIRMAN FINLEY: All right. Excuse me. Just wishful thinking.

(Laughter)

BY MS. KEMERAIT:

Q And, Mr. Gajda, I have questions for you about energy storage and the implications of energy storage for material modification. And similar to the question that I asked of Mr. Riggins, are you aware that this is an issue that's of great interest to NCCEBA, and NCSEA, and IREC, and a number of the interconnection customers?

A (Mr. Gajda) In general, yes.

Q So my questions are going to focus about specifically whether the addition of DC coupled energy storage would constitute a material modification as defined under the North Carolina Interconnection Procedures. And so my questions are going to be about DC coupled energy storage and not AC coupled energy storage. So you can just assume that I'm talking about DC.

A Okay.

Q And to your knowledge has energy storage been added to any of the solar facilities in Duke's North Carolina systems to date?

A I'm not aware of any energy storage being added to any facilities. I can think of a Duke R&D facility which has some energy storage but I can't think of -- I'm not personally aware of any third-party solar facilities at which storage has been added.

Q And for energy storage in North Carolina, is it just one facility that currently utilizes energy storage to your knowledge?

A To my knowledge.

Q And are you aware that there is, as I mentioned, a considerable amount of interest in North Carolina and then I would also say across the country about energy storage being added or developed to solar PV facilities?

A Certainly.

Q And will there be any benefits to Duke's system if energy storage is added to solar facilities?

A That's up for question. That would be -- that's undetermined from my perspective within the aspect of what we're talking about here with the Interconnection Standards. I'm not thinking about benefits or lack of benefits to Duke because the Interconnection Standards really just look to study the impact to the system and power quality and reliability for customers. So they don't really -- the Interconnection Standards don't directly go to quote, unquote, benefits for Duke. And that's kind of a, probably a very wide characterization so.

Q And I would agree with you that the Interconnection Standards are to address the process. But would you agree that energy storage though could address the intermittency of distributed solar power, for example, to provide power when the sun is not shining?

A I mean, I'll say that a storage facility - for example, Duke operates a pump storage facility - has some sort of potential. Although, currently right now we operate that facility as part of Duke's generating fleet and so it's -- there's a very well understood mechanism by which that's operated. And so I think -- I think it would be -- it's well understood because we have a -- Duke has a pump storage facility. I think it's relatively well understood how another energy storage facility owned by Duke and operated in a similar manner might operate. Outside of that I can't really speculate.

Q And so I next want to move on to what the effect of a material modification is. And as background for this issue can you explain what happens if a change to an interconnection request is deemed to be a material modification?

A Yes. So there really are several factors here so part of it is timing. So whether the request, as I stated in my summary statement, the -- a request for material modification is a request to change something about the interconnection request, and that could happen before the study has begun and it could happen also after the study has begun. There's also a separate provision for a change being requested after an Interconnection Agreement has been executed or if the facility is actually in service. When a customer asks to make a change to the design, for example, during the study process the material modification provisions in the Interconnection Standards really just allow for the utility to make a determination, is this change material, hence the term, and I believe the Standards go to a change in the electrical output characteristics. So at the end of the day the utility is trying to determine. And is this an inconsequential change and then, therefore, allow it to proceed because it will not impact the study, it will not impact later queue customers, or any power quality reliability, et cetera. If there is a change in output characteristics, that must be factored into a study. And this change happens -- then now it becomes very key as to whether this change happens before or after the study has begun. Because if a change -- if this change is requested before the study has begun well then the study, of course, can account for it. If the change happens after the study has begun, then at that point a change in output characteristics, the only way that could be properly accounted for would be a restudy, which is not really an official term here because a restudy would imply that the study would now be perhaps repeated and it would take more time in the queue and then other customers -- interconnection customers in the queue would be impacted. So in that sort of scenario, a change is considered material because it has all of those impacts and, hence, is asked to -- or is required to really then move to the end of the queue so those impacts don't occur.

Q Right. So that -- so to give a short answer that would mean in that situation you'd have to submit a new interconnection request, go to the back of the queue, and then the study process would begin again?
A That's correct.
Q And on average how long does it take to complete the study process after an interconnection request has been submitted?
A That, I don't know I can specifically answer that. It highly varies between distribution and transmission interconnections. I know that. And even not accounting for that I don't think I have that information in front of me.
Q Mr. Riggins, do you have the information for distribution and transmission about the length of time it takes currently to complete the study process?
A (Mr. Riggins) So generally an entire System Impact Study from start to finish with all of the components that would have to be looked at is probably going to be in the order of 100 days or something; assuming no tolling and we're not waiting for the customer for information, that

sort of thing. I think in the sense of a material modification there's parts of the study that would have to be re-done. There's probably some parts of the study that would not have to be re-done. So I would expect that the time period would be shorter than a typical System Impact Study that has to go through all of the phases.

Q Thank you. That was one of the questions I was going to ask about the shortening of the process. But 100 days for the initial System Impact Study to be completed, but how long generally is it taking for interconnection customers for the System Impact Study to be begun after the interconnection request has been submitted? How long are interconnection customers waiting for the System Impact Study to begin?

A So, clearly it depends on whether that customer is a Project A or a Project B or they're interdependent. So if they are a Project A and they receive a System Impact Study agreement, then the study should begin very quickly. If they're interdependent they might wait for a long period of time. As we point out in testimony, all of the delays that we've been concerned about establishing timelines for affect those later queued projects. So there are examples where customers are interdependent and there would be a long period of time between an interconnection request and the start of study.

Q And by a long period of time I assume you mean it could be three or more years; is that fair to state?

A Yeah, if that's how long it takes to clear the A and the B project. And if you happen to be number 13 on a particular substation it may be 10 years in a serial process.

Q And, Mr. Gajda, you participated -- I'll return my questions back to you. You participated in a working group, Working Group Number 2 of the stakeholder process; is that right?

A (Mr. Gajda) That's correct.

Q Okay. And the Working Group Number 2 proposed language for a new Section 1.5.2.5; is that correct?

A That's correct.

Q And that particular section pertains to the addition of new equipment to a project and whether it would constitute a material modification. That may be an over-simplification but is that generally correct?

A Yes.

Q And that section, that 1.5.2.5 addresses the material modifications for a DC coupled energy storage; is that right?

A That's one of the pieces in that section, yes.

Q So going forward, just for clarification I'm of going to be focusing on the energy storage portion of that particular section. And I'll begin with Duke and the stakeholders did reach some agreement about what would constitute a material modification during that stakeholder process; is that your recollection?

A We reached a very good general consensus, yes.

Q And would part of the general consensus be that an increase in the maximum generating capacity of a generating facility constitute a material modification?

A I think so. If you're referring to that part of the standards that we looked at editing that talked about the maximum generating capacity, I recall that specific edit and, yes, we agreement on that.

Q Yeah, I was referring to Section 1.5.1.6, and I believe that Duke and the stakeholders were in agreement with that provision?
A I believe that's correct.
Q And then Duke and the stakeholders had also reached agreement that the addition of energy storage on the AC side of the facility would constitute a material modification; is that your recollection?
A That sounds correct.
Q But there was a very significant fundamental disagreement between Duke and the stakeholders about whether energy storage would be added, so if that would be added to the DC side of a system would constitute a material modification; is that your recollection as well?
A Yes.
Q And what did Duke propose in that regard that was objected to by the stakeholders?
A Duke looked at an additional clause which -- and I believe it was 1.5.2.5 which described a change in the DC system configuration. And I believe it was that Duke realized that additional language which was called -- around the profile,

production profile of the facility was going to be key. We can talk more about it but I think that's the piece that you're asking about.

Q Yes, that is. And can you describe what the production profile means?

A Yes. So various generating facilities generate at different times of the day. But really prior to solar most types of interconnections that Duke would consider, I'll just pick on say a hydroelectric landfill gas, we can generally assume that those facilities would operate any time of the day or night. A solar facility was, as we started to study solar, clearly recognized that it would not be generating at say 3:00 a.m. So the basic profile, these sort of normal distribution, or sine wave, whatever you want to call it, the solar production curve is accounted for when we do the study. And we did that early on because we knew that it really didn't make sense for anyone to study what a solar facility might do at three o'clock in the morning especially if that was going to trigger upgrades. So when we think of what a solar facility does across the span of a sunny day we call that the

production profile.
Q And, Mr. Gajda, the stakeholders did not agree with Duke. They believed that energy storage should not have to be delivered during the very same production profile in order to not be deemed a material modification; is that your recollection?
A It sounds generally correct.
Q And in the current study process, does Duke always study a specific production profile?
A Very complicated question but not as bad as the one before. So we -- again, we do account for the production profile. When you say do we account for a very specific profile, that kind of implies that do we account for every specific minute of the day; do we study say every, all 24 hours of the day, and these sorts of things. That goes to the question of what do we study and how do we study. Do we specifically perform a thermal voltage profile study, 24 of them, say for example for the hour of the day? No, we determined that would be unnecessary at this time. It could be necessary at some point in the future. The industry has discussed the concept

of an 8760 Study which refers to the number of hours in a year as being something that's a potential for the future. So we need to remember that that could be a need in the future. It's not right now. So, again, to stick with your question, we account for the fact that a solar facility generates a maximum output, and generally in the middle of the day, and we account for the fact that it's not generating at night, and then we make a number of decisions around our study cases in order to account for that.

Q And what is the specific period that is evaluated during the System Impact Study? I think you've described it as the daylight hours; is that right?

A So that depends. Our distribution studies have evolved to look at the 9:00 a.m. to 5:00 p.m. as a reasonable period of time to capture not only what solar is doing during that time but then what our system load is. So clearly we know that on whatever perfect sunny day might occur that the output at noon is going to be different than the output at 9:00 a.m. But when you do an interconnection study there's two significant components. It's the output of the facility itself studied against the output or, excuse me, not the output, studied against the characteristics of the power system at a specific time or a range of time. So I'm just right now just talking about a distribution study but they generally consider a 9:00 a.m. to 5:00 p.m. period when they go back and look for a historical time when we're looking at say peak load and minimum loads to study against.

Q And does Duke evaluate the full output during that nine to five period for distribution?

A We evaluate -- we do not assume that the facility is operating at full output during that entire time. We go back during that period of time and we look to see what the peak system load was during that time, and we go back and also look for a minimum load occurring during that time, and then we align that with the maximum output of the solar facility, knowing that whatever that system case of say peak load is could occur any time during that period of time. And we essentially went back and found where that was and knew that that was a reasonable point to study against. I hope that answers your question. I'm just trying to capture it accurately.

Q Thank you. And during -- for the thermal voltage study, does Duke study every hour during that nine to five period for distribution?

A So again, we do not run a specific terminal voltage study for every hour like say we don't do a nine, ten, eleven, twelve, et cetera. Again, we go and look back for a peak load study and a minimum load study. And right now at least that -- those are the two, essentially what we call boundary conditions, that we capture for generation on distribution. We turn around and we have to do two more studies which look at peak and minimum load when the generation is not online. And those are the four general studies that capture all possible operating conditions on the circuit.

Q And when Duke is performing its study, does it consider -- does it evaluate any times outside of the daylight hours that you mentioned from nine to five; for example, a winter peak loading time of say 8:00 a.m. or a summer peak time of 6:00 p.m. Does Duke evaluate 8:00 a.m. or 6:00 p.m. during the System Impact Study?

A For a distribution study, no, I don't believe so. We, again, for a distribution study of solar we specifically go ahead and look at that period, that nine to five period that we mentioned a minute ago.

Q What about for transmission?

A So transmission is a bit more complex. And with transmission there's actually slightly different practices in DEP and DEC. And I don't know how deep you want to go, but it's done slightly differently because transmission modeling is a different animal. I mean, to attempt to very quickly describe it, although we have provided I believe in a data request, in DEP right now we evaluate the output of the facility against I believe it is 90 percent of the system peak. And our transmission planning engineers determined some time ago that that was a -- that captured properly what that needed to capture. In DEC it's very similar, and I apologize I can't immediately quote it, it's very similar to that, but I know we have provided it in data requests.

Q Thank you. And even if Duke did consider a -- had been considering a specific and detailed production profile based upon certain hours, that production profile could change based upon equipment that might be used or substituted at the site, the location, the weather, that type of -- those types of changes. So the production profile is not -- can be -- it's not a static type of consideration, it can be more fluid; is that correct?

A That highly depends upon the facility. As you're aware, we suggested in the recommended -- in our redline that the production profile of the facility be submitted, and an hourly production profile. And our feeling was that could be for a number of reasons, energy storage being one of the them; that especially since energy storage can charge and be a load at some times, not just a generator, that capturing production profile. The worst case scenario production profile is valuable.

You bring up a valid point in that that also then comes along with a requirement for the interconnection customer to follow whatever it is it has filed in there. I mean, it goes without saying Duke, as an operator of the system, has a concern that the facility whether or not it will hold to what it said it will do. So I think this is part of the learning that we're doing on how do we evaluate energy storage.

Q Mr. Gajda, in regard to that comment, the interconnection customer can and the utility can require that limiting controls can be installed to ensure that the output that the energy storage delivers is as stated by the interconnection customer; is that your understanding?

A Yes, that's correct. And, in fact, we currently allow that at a number of distribution sites.

Q And for -- so now I'm going to ask you to consider that a situation in which, if the energy storage is added to the DC side of the facility, and if the energy storage does not increase the maximum generating capacity, and the output from energy storage is added only during the same periods that were studied during the System Impact Study as you mentioned the example would be from nine to five; do you believe that the study results would change?

A I think, with all due respect, the number of conditions that you laid out in your question it illustrates why we can't just add that storage and say that everything's going to be okay. I think -- I think -- you know, the question at stake is not whether Duke is okay with storage being added to a facility. The question is whether or not it's responsible from a power quality and reliability perspective to allow it to happen without a study. So again, with all due respect, the number of conditions that you put in front of that I think is our concern. It has to be studied as it actually is. The fact that it's DC coupled really just removes some of the short circuit, and other things that I know you didn't want to talk about, but the fact that it's DC coupled just removes those from the study process. But it doesn't change the fact that the output of the facility can do different things during the time of day and if that's not captured during in the study then we're not capturing the proper operation of the facility.

Q Well --

A (Mr. Freeman) I just want to add something to that to maybe simplify it a little bit. I mean, I've seen with at least one of our solar developers that has a couple of battery devices that they operate and those batteries can go from instantaneous off to almost instantaneous on. So, I mean, it's a spike like that and then it goes across and comes back down. So even inside the day where even solar, the intermittency of solar, it generally doesn't instantaneously go on and come back off. The batteries introduce a whole other complexity to Mr. Gajda's point around -- I mean instantaneous, I'm talking within cycles on/off, and that has huge implications on ramping. It has huge implications on the equipment that's on the distribution circuit, if you're looking at distribution, connected storage, with the ability to manage voltage at -- back at the substation, so it does add a significant amount of complexity that does need to be studied in more detail.

CHAIRMAN FINLEY: But you've got a -- there's a solar project with batteries; is that right?

THE WITNESS: (Mr. Freeman) Well, even with batteries --

CHAIRMAN FINLEY: But do you have a solar facility on your system with batteries that -- other than the R&D project that was mentioned?

THE WITNESS: But even -- even a solar facility with batteries, depending on how it's operated, you can see that instantaneous on/instantaneous off meaning -- off meaning going from charge to discharge. So it does create a very different potentially production profile than --

CHAIRMAN FINLEY: My question is -- I thought you said -- do you have a project on DEC or DEP, a solar project that has batteries connected to it?

THE WITNESS: We do at one of our pilot sites where we're --

CHAIRMAN FINLEY: The R&D project?

THE WITNESS: Correct. Correct. The one I was witnessing was one -- it was a separate project. It's a smaller project that's on one of our -- at one -- interconnected to one of our wholesale customers.

BY MS. KEMERAIT:

Q And, Mr. Gajda, I'm going to move along hopefully pretty quickly about the studies that are performed during the System Impact Study. So to have this move along quickly I'm going to provide a statement and if it's not correct please correct what I'm stating. But for the studies performed during the System Impact Study from the data request that Duke provided, it's my understanding that the studies are the Stability Analysis, the Short Circuit Study, the Protection Study, and the Thermal Voltage Study, and then the Rapid Voltage Change and Flicker Analysis; is that correct?

A That sounds correct.

Q And when DC coupled energy is added to a facility, the only study of the ones that I just mentioned that could potentially change would be the Thermal and Voltage Study; is that correct?

A I believe -- in the data request or testimony I believe we said that it could be Thermal or Voltage, Thermal/Voltage, or a Stability Study I believe. Either one could be impacted.

Q But the Short Circuit Study or the Protection Study would not be impacted, correct?

A That would be our expectation.

Q And so if Duke were to consider or to evaluate whether the addition of energy storage could be safely interconnected you would not have to repeat the Short Circuit Study or the Protection Study?
A Correct. We would not expect to.
Q And in regard to the Thermal Voltage Study and potentially the Stability Analysis, although, my recollection was is that Duke only referred to the Thermal Voltage Study as a study result that could potentially change, but based upon your testimony, we'll talk about Stability Analysis and the Thermal Voltage Study results. If Duke were to consider whether the addition of energy storage that would be provided during the time of the study period or right outside the time of the study period, you would not have to as Mr. Riggins mentioned perform those studies all over again; is that correct?
A (Mr. Gajda) I'm sorry. I was flipping to the section that you were talking about, so could you just repeat that?
Q If Duke were to consider whether the addition of energy storage let's say, for example, at the

6:00 time to help with peak loading would change the study results, you would not have to perform the Thermal Voltage Study or the Stability Analysis all over again; is that correct?

A Well, no, I believe there's a high probability we would have to potentially do that. I mean, again, you're referencing it operating at 6:00 for say peak time, but that's -- our peak may or may not always be at exactly 6:00, so this is where kind of the complication ensues on assumptions about when it would operate. We have to -- we have to know when it's going to operate and how it's going to operate. And the Stability Analysis takes into account the flows on the system and so that's why it has a relation to the thermal voltage so that's why either of those could be impacted, because you are -- you're operating the facility in a different manner than what the study potentially originally called for.

Q Mr. Riggins, did you state earlier though that the studies could be performed in a more expedited manner and would take considerably less time? Was that your testimony earlier?

A (Mr. Riggins) So my testimony was really more reflective of some of the components in the System Impact Study. So when I was saying that I'm thinking about the LVR, line voltage regulator, if there was one of those then you go into sometimes protected time periods where you're looking for right-of-way and looking for ways to build to a point above that device. My assumption was that an existing facility -- you know, if we're just talking about adding storage, that we don't have to go back and do that, and certainly that would be more efficient than having to do the whole System Impact Study. I was not referring to the particular components that Mr. Gajda is referring to.

Q Okay. And, Mr. Gajda, approximately how long does it take to perform the Power Flow Analysis and the Stability Analysis?

A (Mr. Gajda) Well, on the -- so we're kind of back I think to the transmission side and it takes several -- several weeks perhaps of uninterrupted time is what a Thermal Voltage Analysis would take. Stability analyses can highly vary and they're vary labor intensive so I can't give you a good quote on stability analyses.

Q Thank you very much.

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

CHAIRMAN FINLEY: Okay. Let's come back tomorrow at 9:30.

(WHEREUPON, the proceedings were adjourned, and will resume tomorrow at 9:30 a.m.)

C E R T I F I C A T E

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

Kim T. Mitchell
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Kim T. Mitchell
Court Reporter