PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, November 30, 2021

TIME: 2:15 p.m. - 3:43 p.m.

DOCKET NO.: EMP-116, Sub 0

BEFORE: Commissioner Kimberly W. Duffley, Presiding

Chair Charlotte A. Mitchell

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Juno Solar, LLC,

For Conditional Certification of Public

Convenience and Necessity to Construct a 275-MW

Solar Facility in Richmond County,

North Carolina

VOLUME 3

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

FOR JUNO SOLAR, LLC:
Karen Kemerait, Esq.
Ben Snowden, Esq.
Fox Rothschild LLP
434 South Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR THE USING AND CONSUMING PUBLIC:
Layla Cummings, Esq.
Robert G. Josey, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER DUFFLEY: Okay. Let's go back on the record.

MS. CUMMINGS: Public Staff calls Dustin Metz to the stand.

COMMISSIONER DUFFLEY: Do you want to be affirmed or sworn?

MR. METZ: Either or.

COMMISSIONER DUFFLEY: Okay. Place your left hand on the bible.

DUSTIN METZ;
having been duly sworn,
testified as follows:

DIRECT EXAMINATION BY MS. CUMMINGS:

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

A My name is Dustin Ray Metz. My title, I'm an Engineer in the Electric Section of Operations and Planning in the Public Staff's Energy Division. My business address if 430 North Salisbury Street, Raleigh, North Carolina.

Q Thank you. And did you cause to be prefiled in this proceeding 36 pages of direct testimony, also an Appendix A with your education and

experience, and two exhibits on October 26, 2021?
A Yes.

MS. CUMMINGS: Presiding Commissioner, we ask that Mr. Metz's prefiled testimony be copied into the record as if delivered orally for the stand, and that his prefiled exhibits be marked for identification as shown in the prefiled exhibits.

COMMISSIONER DUFFLEY: Without -- any objection?

(No response)

Without objection, that is allowed.

(WHEREUPON, Metz Exhibits 1 and 2 are marked for identification as prefiled.)

(WHEREUPON, the prefiled direct testimony and Appendix A of DUSTIN R. METZ is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. EMP-116, SUB 0

In the Matter of		
Application of Juno Solar, LLC, for a Certificate of Public Convenience and Necessity to Construct a 275-MW Solar Facility in Richmond County, North Carolina	)))))	TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. EMP-116, SUB 0

Testimony of Dustin R. Metz

On Behalf of the Public Staff

North Carolina Utilities Commission

October 26, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Section – Operations and Planning in the Public Staff's Energy Division.

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

A. The purpose of my testimony is to provide the Commission a review and final recommendation on the application for a certificate of public convenience and necessity (CPCN) filed by Juno Solar, LLC (Applicant or Juno) on July 12, 2021 supported by the direct testimony and exhibits of the Applicant's witness, Piper Miller. In response to Commission questions issued in its August 31, 2021 Order Scheduling Hearings, Filing of Testimony, Establishing Procedural Guidelines, and Requiring Public Notice, witness Miller also filed Supplemental Testimony on September 14, 2021.[1]

My testimony has the following sections:

I. Summary of Testimony
II. Description of the Facility and Application Review
III. Transmission Interconnection
IV. Evaluation of the Applicant's Proposed Conditions
V. Affected Systems Concerns
VI. Need for the Facility
VII. Impact to Rates
VIII. Public Staff's Recommendations

[1] Miller Direct and Supplemental Testimony was later filed with portions previously marked confidential unredacted on October 15, 2021 and Exhibit C, Statement of Need, to direct testimony filed unredacted on October 19, 2021.

I. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

Juno proposes to construct a large solar facility (Facility) that would interconnect to the Duke Energy Progress, LLC (DEP) grid in a constrained area and will likely trigger substantial network upgrade costs in DEP, and potentially, other affected systems in the Duke Energy Carolinas, LLC (DEC) and PJM service territories. Juno states that there is a need for the project in the state and region, and that it is in negotiations to sell all of its output to a commercial off-taker in PJM.[2]

DEP has not studied the Juno facility for interconnection, and Juno plans to enter the Transitional Cluster Study (TCS), DEP's first cluster study process after the approval of queue reform by the Federal Energy Regulatory Commission (FERC), this Commission, and the South Carolina Public Service Commission. The Applicant contends that the Commission should grant its request for a conditional CPCN that would terminate if the levelized cost of transmission (LCOT) calculated, once the network upgrades are known, is above $4.00/MWh. Juno does not say at what specific point in time this condition or the termination of the CPCN would be triggered. The Applicant also does not go into any detail on the

[2] Miller Direct, at 13.

process for rehearing the application should the termination provision be triggered and how that may affect other projects in its study cluster.

Juno witness Miller states that the Applicant is caught in a ”patently unfair and unreasonable situation” and a “catch 22” if the Commission refuses to grant it a CPCN prior to making certain milestone payments as part of the TCS, which requires the Applicant to make substantial financial postings, and Juno may incur significant withdrawal penalties if it exits the study process.

I disagree that Juno, or any applicant entering Duke’s TCS or Definitive Interconnection System Impact Study (DISIS), is subject to an unfair “catch 22”. Instead, the Applicant is seeking to shift risk from itself to DEP ratepayers. This is a risk that was known at the time the parties, including DEP and Pine Gate Renewables,[3] agreed to the queue reform process after a lengthy stakeholder process.

In addition, the conditional CPCN as requested does not solve the supposed “catch 22” described by the Applicant. Even if the Commission grants the CPCN with conditions and the network upgrades go above the certain defined dollar amount LCOT as

[3] Pine Gate Renewables is managing the development of Juno Solar’s proposed generating facility and will operate Juno in collaboration with Birch Creek. Miller Direct Testimony, at 1.

requested by the Applicant, the Applicant is still subject to the same financial risk of withdrawal from the TCS.

The Commission cannot make a fully informed decision on the Application until it has been studied by the interconnecting utility and potential affected system costs are known. I recommend that that the Commission deny the CPCN without prejudice, allowing the Applicant to refile its Application once it has obtained its Facilities Study report and once any applicable network upgrades assigned from affected systems studies are known. Not only will the true LCOT be unknown prior to these studies, but also the total magnitude of the network upgrades to ratepayers coming out of the TCS will be unknown, a factor the Public Staff believes the Commission should consider when evaluating the need for a facility studied within a cluster study.

II. DESCRIPTION OF THE FACILITY AND APPLICATION REVIEW

Q. PLEASE DESCRIBE THE FACILITY.

A. The Applicant proposes to construct a 275-megawatt AC (MW_{AC}) solar photovoltaic electric generating facility in Richmond County, North Carolina. The Applicant also describes the potential to add 68.75MW / 275MWh of energy storage.[4] The Facility plans to

[4] Witness Miller states that the Energy Storage System will be subject to change during the design. Miller Direct, at 12, ln. 14-15.

interconnect with the DEP transmission system via the DEP Richmond-Laurel Hill 230kV transmission line. The footprint of the Facility covers approximately 2,600 acres of land, distributed across multiple parcels.

Q. WHAT IS THE APPLICANT'S PROPOSED CONSTRUCTION TIMELINE FOR THE FACILITY?

Witness Miller states on page 9 of her direct testimony that construction is expected to begin on the Facility in the second quarter of 2023, and commercial operation is expected to occur in the third quarter of 2024. Witness Miller further states that the facility will enter the TCS. The TCS is the first cluster study set to commence this year as part of DEP's queue reform effort to move away from an interconnection serial study process to a cluster study approach that allows the utility to allocate costs among multiple projects triggering the need for a system network upgrade. There are multiple phases to the TCS: Phase 1 is power flow and voltage study, estimated to be completed by March 1, 2022; Phase 2 is a stability and short circuit study, estimated to be completed by August 28, 2022; and finally, a Facilities Study, estimated to be completed by late February 2023. According to DEP, the TCS timeline for study concludes with the awarding of Interconnection Agreements in 2023, which could be extended an additional 150 days or more depending on the need for restudies.

Q. DID YOU REVIEW THE APPLICANT'S PROPOSED, AND LATER REVISED, SITE PLAN FOR PROPOSED CONSTRUCTION?

A. Yes. The Applicant revised its proposed site plan, reducing the overall footprint of the Facility, while maintaining the same nameplate capacity output, and identifying lowlands or marshlands that would not be suitable for construction of a solar array or heavy equipment.

Q. DOES THE REVISED SITE PLAN RAISE ANY CONCERNS, OR DO YOU HAVE ANY OBSERVATIONS THAT YOU WOULD LIKE TO BRING TO THE COMMISSION'S ATTENTION?

A. Yes, given my experience with the Public Staff reviewing CPCN applications for solar facilities, it is not uncommon for sites to have numerous modifications to the site layout and boundaries, and even changes in nameplate capacity prior to project completion. In this case, because the Applicant's proposal to issue the CPCN with a condition that is dependent on the ability of the facility to produce the total estimated energy output, a more detailed site map is warranted.

Based on my review of the Application and other publically available topography maps, there are numerous marshland areas, creek beds and other unusable areas on or near the 2,600 acre site. Should the proposed site prove incapable of supporting a facility that can produce the total energy utilized in the initial calculation of the LCOT, the true LCOT may be substantially greater than what is being relied upon in determining whether to grant the CPCN.

The Public Staff has serious concerns that the Applicant, during the construction process, may experience reasonable, but unexpected circumstances that will reduce the nameplate capacity and production profile, and thus cause the true LCOT to dramatically exceed the LCOT on which the conditional CPCN is based. To illustrate this concern, see Metz Figure 1 below that evaluated changes in the LCOT with a different network upgrade costs, changes in annual capacity factor (energy production), and reduction in the nameplate rating. I will explain the different network upgrade costs later in my testimony.

Metz Figure 1

Network Upgrade Costs ($M)	13.0	16.8	51.7
	LCOT $/MWh		
Applicant as filed, 275MW, 40 years @ 25.55% CF	1.01	1.3	4.00
275MW, 40 years @ 23.55% CF (reduction in CF)	1.12	1.44	4.44
250 MW, 40 years @ 25.55% (Reduction in Nameplate)	1.11	1.43	4.40
250 MW, 40 years @ 23.55% (Reduction in Nameplate and CF)	1.23	1.59	4.89

Q. DID THE STATE CLEARINGHOUSE HAVE ANY COMMENTS?

A. Yes, the State Clearinghouse filed additional comments on October 15, 2021. The Department of Natural and Cultural Resources (DNCR) has requested additional information. DNCR noted that it has sent a previous letter about this project on November 22, 2016 recommending a comprehensive archaeological assessment. DNCR states that it still recommends such an assessment and there are areas of high probability for archaeological sites. DNCR makes an additional recommendation to have a cemetery on-site mapped by a licensed surveyor.

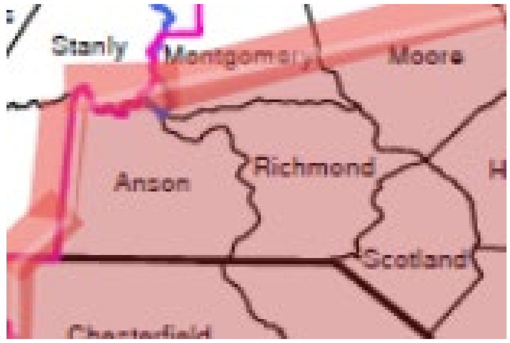
III. TRANSMISSION INTERCONNECTION

Q. HAS THE APPLICANT PROPOSED TO INTERCONNECT IN A PORTION OF DEP'S SERVICE TERRITORY THAT PREVIOUSLY HAS BEEN IDENTIFIED AS CONSTRAINED (CONGESTED)?

A. Yes. DEP's open access transmission interface, OASIS, website provides a map as well as a list of individual transmission lines that are constrained,[5] which I have included as Metz Exhibit 1. Richmond County, in which the Applicant has requested interconnection, is part of the red or constrained area. Metz Figure 2 is a detailed view from Metz Exhibit 1 that focuses in on Richmond County.

[5] DEP Constrained Infrastructure, *available at* https://www.oasis.oati.com/cpl/index.html , under drop down "Generator Interconnection Information", DEP-DEC Constrained Areas and DEP lines and Subs Constrained Infrastructure (last accessed Oct. 25, 2021).

METZ FIGURE 2



Because the constrained area is relatively broad, it is necessary to evaluate the constrained substation and transmission list, which I have included in Metz Exhibit 2.[6] In its original Application and supporting testimony, Juno states that it plans to interconnect to the (DEP) Richmond-Laurel Hill 230 kV transmission line. Metz Exhibit 2 shows that the Laurinburg-Richmond 230 kV line at the Laurel Hill Substation is constrained even prior to incorporating Juno's interconnection request.[7] It is unclear which other projects will potentially impact this already constrained section of the DEP system, nor is it clear how many interdependent projects exist in the interconnection queues, how many of those projects will choose to enter the TCS, and ultimately complete all phases of the TCS, and become commercially operational. In addition, DEP has identified

[6] Constrained Substation and Transmission List, *available at* https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/DEP_Lines_and_Subs_Constrained_Infrastructure_Tranche_2.pdf (last accessed Oct. 25, 2021).

[7] DEP Constrained Infrastructure, p. 4. Note, all items listed (both red and black text) are constrained sections of the system. The item text in red are new lines and parts of the system that was updated following CPRE Tranche I. There has been no new maps or list updates to Duke's OASIS site following the completion of CPRE Tranche II.

multiple other transmission lines and substations in Richmond County that are already constrained prior to the TCS.

Q. HAS DEP COMPLETED A POWER FLOW OR OTHER GENERATOR INTERCONNECTION STUDY OF THE FACILITY?

A. No. DEP has not completed a power flow analysis for the Facility.[8] The Public Staff believes that without a power flow analysis done by the utility based on projects that have entered TCS, and subsequent system impact study and facilities study, the review of the CPCN is premature.[9,10]

Q. DID THE APPLICANT COMPLETE ITS OWN POWER FLOW ANALYSIS?

A. Yes. On page 1 of Supplemental Testimony, witness Miller states that Birch Creek, which owns Juno, performed a steady-state power

---

[8] For purposes of my testimony, I am referring to "power flow analysis" as the combination of power flow, voltage and short circuit analysis or other analysis required to interconnect a generation facility, inclusive of affected system studies when applicable.

[9] The Public Staff has taken similar positions in other EMP dockets, either recommending the Commission consider the Application after the network upgrade costs are known or requesting a condition that the Applicant will be responsible for the network upgrade costs that are unknown. See EMP-102, Sub 1, Supplemental Testimony of Metz (Jul. 7, 2021), at 17; EMP-108, Sub 0, Supplemental Testimony of Lucas (Jul. 22, 2020), at 14-15; EMP-109, Sub 0, Testimony of Lucas (May 15, 2020), at 6-7; EMP-110, Sub 0, Supplemental Testimony of Lawrence (Nov. 16, 2020), at 8-10; EMP-111, Sub 0, Testimony of Lucas (Sept. 18, 2020), at 11-12, 19; EMP-114, Sub 0, Testimony of Lawrence (Mar. 22, 2021), at 7-8; EMP-115, Sub 0, Testimony of Lucas (Apr. 14, 2021), at 8-9; EMP-117, Sub 0, Testimony of Lucas (Oct. 19, 2021), at 13-15.

[10] This recommendation is consistent with the Public Staff's recent Petition for Rulemaking to Revise Commission Rule R8-63 in Docket No. E-100, Sub 176. In that docket, the Public Staff recommends a rule change that would allow the Public Staff to deem merchant generator CPCN applications incomplete without this cost information.

flow study. In discovery requests, the Public Staff investigated the underlying assumptions that Birch Creek utilized.

Q. DID YOU REVIEW THE APPLICANT'S POWER FLOW ANALYSIS?

A. Yes, I did review the Applicant's Power Flow analysis and asked several questions in discovery. I reviewed their assumptions on the base case and the change case. After my review, I have two observations. First, I do not believe that the Applicant can provide an accurate or useful analysis without knowing with certainty the other projects that will enter the TCS and remain in the TCS through the completion of the Phase 2 report, at a minimum. Second, the Applicant only completed a summer peak power flow analysis. Given that the Applicant had considered battery storage to be discharged during the winter peaks, a winter study should be completed and possibly a shoulder season study.

Q. HAVE YOU PROVIDED TESTIMONY IN OTHER CPCN PROCEEDINGS FOR MERCHANT GENERATION THAT EVALUATED NETWORK UPGRADES?

A. Yes. I have provided testimony in many dockets that discuss network upgrades, and have worked with other members of the Public Staff on this subject.

Q. PLEASE SUMMARIZE YOUR TRANSMISSION ANALYSIS AND THE COMMISSION'S DECISION IN DOCKET NO. EMP-105, SUB 0 (FRIESIAN) THAT IS RELEVANT TO THIS PROCEEDING.

A. In summary, the Public Staff evaluated both the magnitude of network upgrade costs and the LCOT for the utility to safely interconnect the facility to a constrained area of DEP's grid to maintain reliability. The LCOT metric is a straightforward tool that allowed consideration of the required upgrades and their respective costs to the transmission system on a unit of energy conversion basis.

The Commission in the Friesian case did not consider the LCOT as a definitive test with pass or fail criteria; the Commission considered it as a benchmark of reasonableness of the costs to interconnect generation. The total magnitude of the upgrades, $223.5 million, informed the total rate impact of the facility to DEP ratepayers, which was also an important consideration.

While the specifics of the Public Staff's review of Friesian's application were unique to the facts and circumstances of that facility, the sheer magnitude of the network upgrade costs and the relatively high LCOT weighed heavily towards the Public Staff's recommendation to deny the CPCN. In the Public Staff's view, interconnection of the Friesian facility would result in costly overbuilding and inefficient planning of the transmission system and was, therefore, not in the public interest. The existence of a completed System Impact Study and Facilities Study report was crucial to the Public Staff's ability to make its final recommendation; however, the Juno Facility does not currently have these studies.

I would further note that in the Friesian case, the estimated costs of the network upgrades increased even after the Facilities Study, and then decreased again.[11] In its June 11, 2020 Order denying the certificate, the Commission stated "[r]ather than assuage the Commission, the various swings in the estimated cost of the network upgrades raise further concern."[12] It is possible that Juno and its cluster will have similar swings in cost estimates and that, in the Public Staff's view, is another reason the Commission should wait for the results of interconnection studies prior to issuing a CPCN.

Furthermore, whatever the costs are to interconnect Friesian at this point in time[13] is potentially relevant in this proceeding if Friesian enters the TCS and is in a cluster study with Juno's Facility.

[11] See Late Filed Exhibit, Docket No. EMP-105, Sub 0, filed by DEP on January 8, 2020, and corrected supplemental late-filed exhibit filed on April 16, 2020.

[12] Order Denying Certificate for Merchant Generating Facility (Friesian Final Order), Docket EMP-105, Sub 0 (N.C.U.C. June 11, 2020) at 24, fn. 8.

[13] Due to the passage of time, Friesian would likely have to be studied again whether it enters Transitional Cluster or Transitional Serial Study.

Q. PLEASE SUMMARIZE YOUR MOST RECENT TRANSMISSION ANALYSIS IN DOCKET NO. EMP-102, SUB 1 (PITT SOLAR).

A. While Pitt Solar is still pending before the Commission, and the specifics of that application are unique to it, the crux of my evaluation in that case was to inform the Commission that without a completed Affected System study, I could not calculate the transmission impacts and provide a recommendation to the Commission.

Q. MR. METZ, HAS THE PUBLIC STAFF MADE SIMILAR RECOMENDATIONS TO THE COMMISSION RECENTLY?

A. Yes. As we learn more about the complexities of increasing amounts of generation in specific constrained sections of the transmission system, it is necessary to scrutinize the potential ramifications of the upgrades, costs, and commensurate value to rate payers to ensure long term efficient planning while providing reliable service at affordable rates. I believe this Commission's review of merchant generator applications and the total cost of construction of those facilities, especially network upgrade costs that are ultimately passed on to ratepayers, is key to ensuring the statutory goals of N.C.G.S. § 62-110.1 are met.

IV. EVALUATION OF THE APPLICANT'S PROPOSED CONDITIONS

Q. THE APPLICANT REQUESTS A CONDITIONAL CPCN. CAN YOU DESCRIBE THOSE CONDITIONS?

A. Yes. The Applicant requests the Commission issue a conditional CPCN that allows network upgrades up to a certain LCOT amount, after allocation among multiple TCS projects. If that amount is exceeded, witness Miller proposes that "CPCN will automatically terminate and be of no further force and effect unless Juno Solar requests further proceedings to consider whether the CPCN should not be terminated, in which case the CPCN will not be terminated unless so ordered by the Commission."[14]

Q. UNDER THE APPLICANT'S ASSUMPTIONS OF THE TRANSMISSION ESTIMATES, PLEASE DESCRIBE HOW THE COMMISSION COULD EVALUATE THESE COSTS.

A. Using the Applicant's assumptions, the network upgrades would cost $13 million (assumed to be the assigned cost to the Facility by the Applicant's power flow analysis), and in a worst-case scenario, $16.84 million. In this scenario, 100% of the cost was assigned to Juno assuming no other projects were allocated a part of the estimated upgrade costs or those projects subsequently withdrew

[14] Miller Direct, at 24.

from the study process.[15] The magnitude would equate to a LCOT range of $1.00/MWh to $1.30/MWh (See Metz Figure 1), assuming Juno's generation output occurs at its planned levels, the final construction costs are equal to the estimates and no affected system costs are triggered. Under these assumptions, the Public Staff would agree that the costs are reasonable in both magnitude and LCOT. However, the network upgrade costs for the facility should not be reviewed in isolation, but rather, in context of other facilities likely to interconnect in the same cluster.

Q. IF THE APPLICANT'S TRANSMISSION ESTIMATE ASSUMED A ~$1.00/MWH LCOT, WHY IS THE APPLICANT REQUESTING A $4.00/MWH LCOT CONDITION?

A. Witness Miller states that a $4.00/MWh LCOT "represents the amount that Birch Creek believes to be a just and reasonable threshold which will serve to facilitate the state and Duke's renewable energy goals while not burdening ratepayers with reimbursement of unduly high network upgrade costs."[16] Witness Miller does not

---

[15] Once all the required studies are complete, inclusive of affected system impacts when applicable, projects will be assigned their respective cost responsibility for transmission upgrades. For illustrative purposes, assume that a specific transmission upgrade of $10M was identified and there are four projects of 20MW, 10MW, 5MW, and 1MW for a total of 36MW. The $10M would be assigned to each of the projects based on their MW rating. 20MW project would be assigned 55.55% (20MW of the single facility divided 36MW of the total aggregated facilities triggering the upgrade) of the costs or roughly $5.55M. The 10MW project = $2.78M, 5MW project = $1.39M, 1MW project = $0.28M.

[16] Miller Direct, at 3.

provide any analysis for the total impact this would have to ratepayers if applied to other merchant plant CPCN applications or how merchant generators wheeling power into PJM will help Duke or the State meet its renewable energy goals. Just for the Facility, however, $4.00/MWh represents an approximate total of $51.7 million in upgrade costs that will be reimbursed by DEP ratepayers pursuant to Duke's Open Access Transmission Tariff (OATT) regardless of whether that power benefits North Carolina ratepayers or not.

Q. HAVE YOU EVER TESTIFIED THAT THE LCOT CRITERIA IS THE ONLY PASS OR FAIL TEST FOR A MERCHANT POWER GENERATION PLANT, OR ANY CPCN APPLICATION FOR THAT MATTER?

A. No, I have never testified that the LCOT is a pass/fail test and I am not doing so here. I am advocating that the LCOT is a factor to be considered along with the total magnitude of the costs, as I have every other time LCOT has been evaluated. Furthermore, the need for the power in the State and the region must also be balanced against that cost and long term planning for the state.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE LCOT PROPOSED BY THE APPLICANT?

A. The methodology Juno has used to calculate LCOT based on its steady-state power flow study is consistent with the Public Staff's methodology used in other proceedings. However, I believe that the proposal fails to address the total magnitude of the upgrades for all the projects in the TCS. Also, the proposal does not provide a justification outside of the LBNL study benchmarks for how granting the CPCN based upon an LCOT of $4.00/MWh or less allows the Commission to take into account methods for providing reliable, efficient, and economical electric service. [17]

Q. DO YOU HAVE CONCERNS WITH A CONDITIONAL CPCN WITH CONTINUED INCREASES IN TRANSMISSION CONSTRUCTION ESTIMATES, AND CAN YOU EXPLAIN WHY A PHASE 1 POWER FLOW ANALYSIS TO DETERMINE A LCOT IS PROBLEMATIC?

A. Yes. My concerns are reflected in witness Miller's supplemental testimony, in which she acknowledges industry trends leading to rising transmission costs, stating "transmission costs have generally risen, due to: 1) increasing materials and labor costs, and 2) the tendency of these costs to increase with increased solar penetration

[17] N.C.G.S. § 62-110.1(d) states "[i]n acting upon any petition for the construction of any facility for the generation of electricity, the Commission shall take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economical electric service."

on the system."[18] The Public Staff conducted discovery on this topic, and found the Applicant's response to be thorough, responsive, and illustrative of why a conditional CPCN based on any power flow cost estimate is premature prior to receiving a Facilities Study report. In response to Data Request 2-11 related to witness Miller's statement above, Juno states (emphasis added):

> The statement that interconnection costs have risen is based on industry observation and is not one that can be readily demonstrated on a project-to-project basis, as each project has its own unique interconnection requirements. Birch Creek has, however, observed systematically underestimated interconnection costs from the point of System Impact Study ("SIS") to Facilities Study ("FS"), where it is not unusual of late to see FS cost estimates **roughly doubling the corresponding estimates made during the SIS phase**, including projects studied by DEP and DEC.
>
> Rising hard costs and labor costs across the nation presumably impact all interconnection costs. The Employment Cost Index maintained by the Bureau of Labor Statistics reflected a year-over-year increase of 2.6% as of the last quarter, and many commodity costs have risen steadily since early 2020, with steel commodity costs in particular seeing an over 200% price increase since March 2020 and contributing substantially to rising costs of electrical infrastructure.
>
> Furthermore, in the Friesian docket, DEP filed a late filed exhibit on January 8, 2020 to explain the reason for the increase in cost estimate for the network upgrades from $116 million (Initial Estimate) to $224.4 (IA Estimate). DEP provided information that the increase in costs is not applicable to just the Friesian

[18] Miller Supplemental, at 3.

project, but applies generally to transmission projects. DEP provided the following information:

- Labor costs – As was discussed extensively during the hearing, there has been an increase in labor costs for this type of work. This updated labor cost information was then used to develop a more refined estimate of the per mile labor costs that led to the updated estimate.
- Environmental costs – Similarly, the Company continues to experience increased costs for environmental compliance and such increased costs were factored into the IA Estimate. For instance, the Company's experience with more recent projects has demonstrated that matting costs (a significant cost item) were often far greater than initial estimates.

Q. DO YOU AGREE WITH THE APPLICANT THAT ENTERING THE TCS (OR DISIS) WITHOUT A CPCN CREATES A "PATENTLY UNFAIR AND UNREASONABLE SITUATION" FOR THE APPLICANT?

A. No. I do not agree that it is unfair or unreasonable, and it is extremely challenging to make a recommendation that relies solely on the LCOT for an acceptable or unacceptable amount of reasonableness. The TCS is a voluntary process for the transformation of serial studies to large-scale cluster studies. The construct of the TCS and the DISIS occurred through a stakeholder process, which determined the phases, milestones payments, withdrawal penalties, and timing requirements. This process was approved by the North Carolina Utilities Commission, the Public Service Commission of

South Carolina, and the Federal Energy Regulatory Commission. The Public Staff believes that solar developers will have a fair opportunity to participate in this process. A CPCN is not required to meet any readiness milestones and the Facility, and others similarly situated, can apply for a CPCN once the process has concluded.

V. <u>AFFECTED SYSTEMS CONCERNS</u>

Q. PLEASE IDENTIFY ANY CONCERNS YOU HAVE WITH AFFECTED SYSTEMS STUDIES AND THE TCS.

A. An Affected System (AS) is an adjacent utility to the interconnecting utility, in this case DEP, where the output of a generation facility located in DEP negatively impacts the AS (i.e., causes overloads or other reliability issues). Each Balancing Area reviews its own respective interconnection queues to determine whether or not it is an AS. Neither TCS nor DISIS is a joint modeling exercise between DEP and DEC. AS studies between DEP and DEC will be treated similarly to how PJM and DEP coordinate AS studies, as has been discussed extensively in other pending dockets before this Commission.

I have multiple concerns related to the AS study process because: (1) the Facility's production profile will match that of the current large solar capacity and energy in DEP, (2) the Facility will interconnect in a constrained area, and (3) the Facility is in close proximity to the

DEC system. The Facility, along with others nearby, will likely trigger a need to evaluate the DEC-DEP tie lines to identify potential upgrades in the DEC system.[19] While other adjacent utilities are further away from the Facility than DEC, those utilities could be AS's as well. Thus, projects in PJM and their respective power flows will have to be evaluated in conjunction with the TCS as well.[20]

The Public Staff sent a data request to Duke to ask about the coordination of AS studies and the TCS. Duke's Large Generator Interconnection Agreement (LGIA) governs the AS Study process.[21] Duke explained in response to a data request that:

> Coming into Phase 1, Juno Solar will not have any indication of affected system requirements or cost, since the project will not have been studied. After the release of the Phase 1 Study results but before the end of Phase 2 customer engagement, Juno Solar would be notified that an affected system study may be required. However, the timeline does not support receiving affected system requirements and cost before Phase 2 milestones are due. The preferred timeline would be for affected system studies to occur during the Phase 2 Study so that the costs and requirements would be known before posting M3 milestones prior to Facilities Study. In the case where a potential affected system was identified during Phase 2 study, this may not be possible. [22]

[19] This is heavily dependent on what is the base case scenario and what generation is added in the change case.

[20] In supplemental testimony, witness Miller identifies PJM but not DEC as a potential affected system. Miller Supplemental, at 4.

[21] Affected Systems Business Procedure for Duke Energy, *available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/Affected_Systems_Business_Procedure_v2_final.pdf (last accessed Oct. 25, 2021).

[22] Response of DEP to Public Staff DR 1-8.

A project or multiple projects could be in both the TCS and the LGIA AS study processes, at the same time with each process having its own estimated network upgrade costs. Duke has a goal to complete an AS study within 60-90 days (but the LGIA does not have definitive completion timelines but has goals with a degree of flexibility). Once the studies are complete, the LGIA and TCS processes are moving in parallel and the project, if it triggers a network upgrade on an affected system, will have to enter to an Affected System Operating Agreement with the affected utility and establish milestone payments and timelines.

VI. <u>NEED FOR THE FACILITY</u>

Q. DID YOU EVALUATE THE APPLICANT'S STATEMENT OF NEED FOR THE GENERATION FACILITY?

A. Yes. The Applicant stated a need for the generation output of this facility in PJM given PJM's expected load growth. The Public Staff asked the Applicant to describe in more detail how North Carolina consumers and the North Carolina electrical system needed this facility:

> Birch Creek anticipates that this project will "wheel" the majority of its output to PJM, which will primarily provide clean energy benefits to the Dominion system including the portion of North Carolina included in its footprint. Moreover, the volume of clean energy to be produced by Juno Solar would substantially displace existing CO_2-emitting resources, in turn facilitating regional decarbonization consistent with North

> Carolina's clean energy policy goals. Juno also anticipates selling a portion of its generation on an "as-available" basis to DEP when not economic or feasible to charge its battery or deliver it to PJM, directly providing the utility and state with additional clean energy toward their respective targets.[23]

Through discovery, the Applicant has stated, the "[p]roject will remain incentivized to discharge energy from the battery storage system during these winter morning peak hours [6am to 8am]".[24]

Q. WITNESS MILLER STATED IN HER DIRECT TESTIMONY THAT ALL SIX SCENARIOS OF DEP'S 2020 INTEGRATED RESOURCE PLAN (IRP) RESULT IN INCREASED SOLAR AND STORAGE CAPACITY ON THE DEP SYSTEM. IS IT YOUR UNDERSTANDING THAT PLAN A OF THE 2020 IRP <u>DID NOT</u> ECONOMICALLY SELECT ANY NEW SOLAR OR SOLAR PLUS BATTERY STORAGE IN THE 15-YEAR PLANNING HORIZON?

A. Yes. Plan A did not economically select any new solar, or solar plus battery storage in addition to the mandated solar or expected PURPA queue materialization that is required by law at the time of the filing of the 2020 IRP.

Q. **WILL THE FACILITY DISPLACE ANY CARBON EMITTING GENERATION?**

[23] Response to Public Staff Data Request 1-8.
[24] Response to Public Staff Data Request 1-10.

A. There is no evidence, at this time, that the Facility will or will not displace carbon emitting resources. Energy and capacity are needed for continued load growth, as well as for retiring generation (carbon emitting or not), so the output of any new generation facility may just be incremental energy added to the system to meet load growth and may or may not contribute to dependable capacity depending on whether the energy storage system will be dispatched at the time of need. The broad assertion that it will displace carbon-emitting resources is not convincing, as there was not an evaluation provided to it would displace carbon-emitting resources in DEP or PJM.

Q. IS THERE ANY OTHER REASON NON-CARBON EMITTING GENERATION WOULD BE NEEDED IN THE STATE OR REGION?

A. In the time since the Applicant filed testimony, the General Assembly enacted a new law, S.L. 2021-165 or H951. This law requires the Commission to develop a Carbon Plan and take all reasonable steps to reduce emissions by 70% over 2005 levels by 2030. This will undoubtedly lead to the retirement of fossil fuel units and require procurement of new non-carbon emitting generation on the Duke Energy system to serve load. At this point, however, prior to the development of the Carbon Plan, it is premature to assume that the Facility would be needed to assist in meeting those goals. The law is technology agnostic and the Carbon Plan must comply with current law and practice with regard to least cost planning for generation in achieving carbon reduction goals and determining the generation and resource mix.

Q. WOULD YOU AGREE THAT PJM HAS IDENTIFIED THE NEED FOR NEW GENERATION, BOTH ENERGY AND CAPACITY?

A. Yes. However, PJM would need to evaluate the current interconnection queues and the historic PJM capacity markets to identify if there is truly a short fall of new projects to meet its needs. The PJM interconnection queue, inclusive of Virginia and North Carolina, has voluminous amounts of generation, particularly carbon free generation, seeking to interconnect. Given the interconnection queues, I find it doubtful that PJM energy and capacity needs are dependent on the Facility.

Based on my review of the PJM interconnection queue, the Applicant has not demonstrated the need for the Facility or that it has to be located in the DEP service territory to serve PJM.

Q. DID YOU REVIEW THE 2021 PJM LOAD FORECAST REPORT?

A. Yes, I did.[25] PJM is expecting peak load growth of 0.3% for the next 10 years and 0.2% over the next 15 years, with a summer forecasted peak of 153,759 MW in 2031 and winter forecasted peak of 135,568 MW in 2030/2031. However, compared to the 2020 PJM Load Forecast, the summer peak will decreased 1.5%, a reduction of 2,209 MW in study year 2026. It is noteworthy that page 33 of the report (listed as page 28), shows the Dominion (DOM) Zone is shifting to a winter peak and winter load growth is nearly double that of summer load growth. In comments to FERC on the Advance Notice of Proposed Rulemaking for transmission planning, Dominion stated:

> As of October 2021, approximately 47,640 MW of renewable energy is currently in the PJM queue for the DOM Zone. Of 568 projects in the PJM queue for the DOM Zone, only 6 are for the development and interconnection of non-renewable resources, i.e., 562 are for the development and interconnection of intermittent renewable projects.[26]

[25] PJM 2021 Load Forecast Report, *available at* https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx (January 2021).

[26] Comments of Dominion Energy Services, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, FERC Docket No. RM21-17-000 (Oct. 12, 2021), at 16.

VII. <u>IMPACT TO RATES</u>

Q. SIMILAR TO THE PUBLIC STAFF'S ANALYSES OF FRIESIAN, DID YOU EVALUATE THE RATE IMPACT OF THIS PROJECT?

A. Yes. I requested a rate impact analysis from DEP in this case. DEP provided the rate impacts to customer classes for increases in transmission costs, similar to that which a merchant power plant would trigger.

Table 1 below illustrates the calculation needed to estimate impacts to NC Retail and Wholesale Rates.

Table 1. Rate Impact Calculator Assuming No Network Upgrade Costs

Network Upgrades ($mm)	$0	*$mm+ FERC Interest 5yrs@3.25%*
Depreciation Rate: Property Tax Rate DEP WACC (Pre-Tax)	2.23% 0.36% 8.44%	*60 years (NC-1001)* *NC-1001* *DEP Settlement*
Carry Cost	11.03%	
Revenue Requirement	$0.00	
Book Revenues DEP Retail Transmission Allocation	$3,921 59.67%	*E2 sub 1219 Compliance Exhibit #2 (col_J+col_N)* *DEP-COS NC Retail Demand Allocation (NC-1001)*
NC Retail Rate Impact	***0.00%***	
OATT Net Rev Requirement ($mm) Wholesale Transmission Allocation	$240.5 32.36%	*Formula Rates pg1 line 8* *Formula Rates pg5 line 6*
Wholesale Transmission Impact	***0.00%***	

Q. USING THE CALCULATIONS IN TABLE 1, PLEASE LIST THE NC RETAIL AND WHOLESALE IMPACTS USING THE COSTS LISTED IN YOUR TESTIMONY.

A. I put multiple costs into the Network Upgrades field and my results are displayed in Table 2, below. The results provide a perspective on the magnitude of the cost and the associated impact to rates for both North Carolina retail and wholesale customers if the Facility triggers upgrades and the cost of the upgrades are reimbursed to the Applicant.

Table 2: Rate Impacts

$(M)	NC Retail Rate Impact	Wholesale Rate Impact	Notes
13	0.02%	0.59%	The Applicant's assumed assigned cost
16	0.03%	0.73%	The Applicant's assumed total cost
51	0.09%	2.29%	Equivalent $4.00 LCOT

A 2.29% increase to wholesale rates at the assumed $4.00/MWh LCOT scenario is noteworthy, when compared to the percent in change resulting from the Facility in isolation. When factoring in the total network upgrades that may or may not be included for all projects in the TCS, the percent increase will be much higher.

This analysis accounts for upgrades that may be required in the DEP service territory. There may also be additional AS costs. Any analysis of need for the Facility should also take into account the need on the affected system if it is determined that network upgrades are triggered on a neighboring utility's system.

VIII. PUBLIC STAFF'S RECOMMENDATION ON THE CONDITIONAL CPCN APPLICATION

Q. FOR THE PURPOSES OF THIS APPLICATION, DOES THE PUBLIC STAFF AGREE WITH A CONDITIONAL CPCN?

A. Not in this case. The Public Staff frequently recommends the granting of CPCN applications with conditions. We believe, however, that it is premature in the development process to consider conditional CPCNs for facilities based on a predetermined LCOT cap before the facility has been properly studied. We also believe that the Applicant has failed to present sufficient reasons why the Commission must act before system network upgrade cost estimates are available.

In the Friesian case, the Commission found that it is appropriate to consider the total cost of siting a generating facility, and that the CPCN statute obligates the Commission to analyze the long-range needs for expansion of facilities to achieve maximum efficiencies.[27] Consistent with that decision, the Public Staff recommends that the

[27] Friesian Final Order, at 17, *citing* N.C.G.S. § 62-110.1(c).

Commission consider the Facility once it has more certain cost information.

Other than the unknown magnitude of costs associated with the TCS and any affected systems costs, the Applicant's requested condition presents other problems. The upcoming TCS will be the first of its kind for generating facilities in the Duke balancing areas. The Public Staff is concerned that if the costs go over the predetermined conditional threshold, withdrawals and delays may occur while the Commission rehears the CPCN application at the request of the Applicant. Complaints regarding the process may occur at the end of the multiyear study and undermine the results of the TCS.

Furthermore, the Public Staff believes that the Applicant is shifting risk from itself, unjustly, onto captive ratepayers, based on a metric that can be greatly changed if the Facility changes its design (i.e., the use of a battery) or reduces its nameplate capacity prior to commercial operation or even over the life of the project. The Facility is in a known transmission constrained area of the DEP system, and high network upgrade costs are likely. The risk should remain with the Applicant, who will profit from the development of the Facility, especially if it contracts to sell output outside of DEP.

Q. PLEASE EXPLAIN FURTHER, WHY THE TIMING OF THE CONDITION WITH EITHER AN AUTOMATIC TERMINATION OR FURTHER HEARINGS AT THE COMMISSION GIVES YOU CONCERN.

A. In discovery, the Public Staff asked Juno when the study process the $4.00/MWh LCOT condition should be evaluated, and the Applicant's response stated, "Birch Creek believes it is appropriate that Juno's CPCN no longer be conditioned at the point of execution of an Interconnection Agreement."[28]

There are specific timelines and milestones that have to be met in the TCS process.[29] Those timelines and payments were determined after a robust stakeholder process and may be impacted by any Commission proceedings (or automatic CPCN terminations) that cause a project to withdraw. Juno will be awaiting the results of that an AS study in parallel to the TCS process, and any affected system

---

[28] Applicant Response to Public Staff DR 1-21.

[29] The Public Staff has determined the following timeline for the TCS based on Duke's Queue Reform presentations available on OASIS and filings in the interconnection docket:

Readiness Establishment Window (60 days): Sep. 1 to Oct. 31, 2021
Customer Engagement Window (30 days): Nov. 1 to Nov. 30, 2021
Phase 1 Power Flow/Voltage (90 days): Dec. 1 to March 1, 2022
Issuance of Phase 1 Study Report (30 days to Phase 2 deposit)- March 31, 2022
Phase 2 Stability and Short Circuit (150 days) : April 1 to Aug. 28, 2022
Issuance of Phase 2 Study Report (30 days to Facilities Study Deposit)
[Possible Phase 3 restudy-of required add 150 days]
Individual Facilities Study (150 days): September 27, 2022 through Feb. 24, 2023
Issuance of Facilities Study Report: Feb. 24, 2023
[Phase 3 restudy potentially takes the timeline out to August of 2023]

See Duke Energy Queue Reform Stakeholder Meeting Presentation, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/Duke_Energy_Queue_Reform_Stakeholder_Meeting_Presentation-_March_16_2021.pdf (last accessed Oct. 25, 2021).

study costs would have to be calculated in determining the Facility's LCOT. These two study processes are not aligned which will make it difficult to determine the timing to enforce the proposed LCOT cap and the impact that would have on other projects in the TCS.[30]

Q. WHAT IS THE PUBLIC STAFF'S FINAL RECOMMENDATION?

A. The Public Staff requests that the Commission deny the application at this time, without prejudice, and allow the Applicant to refile once it has more certain cost information. We specifically request that the Applicant refile the application no earlier than after a completed Facilities Study from the TCS process, and a completed AS, if applicable.

---

[30] Public Staff Comments on Queue Reform, August 31, 2020, Docket No. E-100, Sub 101, first state our concerns with the coordination of affected systems studies. On page 8, the comments state:

> In addition, the Public Staff notes that due to increasing activity for large merchant generation seeking transmission interconnection into PJM in the DENC service territory, several of DEP's transmission lines near the DENC system have been identified as being impacted or "affected" by the interconnection customers participating in PJM's cluster-based transmission study process.
> The Public Staff has recently raised concerns regarding the timing and allocation of these affected system costs in comments and testimony it has filed in merchant applications for certificates of public convenience and necessity. The Public Staff notes that these affected system studies must also be aligned with Duke's queue reform measures to ensure that the upgrades identified in an affected system are appropriately included in the baselines for Duke's own cluster study process, and that the cost allocation provisions applicable to affected system projects are revised to be consistent with Duke's efforts to assign costs to those projects that contribute to the need for the network upgrades.

It is the Public Staff's view that the schedule of the TCS process allows adequate time for an uncontested CPCN review process. If obtaining the CPCN causes delays in the construction timeline, the Applicant also has the option of filing a motion for limited construction authority.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associates of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience, including six years with direct employment with Framatome, where I provided onsite technical support, craft oversight, engineer change packages and participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations) member, avoided costs and PURPA, interconnection procedures and power plant performance evaluations; I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

BY MS. CUMMINGS:

Q Mr. Metz, do you have any changes to your prefiled testimony or exhibits?

A I do not.

Q If I asked you the same questions today on the witness stand, would your responses be the same as the answers you have prefiled?

A Yes, they would.

Q Mr. Metz, would you please provide a summary of your testimony.

A The purpose of my testimony provided the Commission with the results of Public Staff's investigation on Juno Solar's Application for a 275 MW AC Merchant Power Plant. The Public Staff recommends that the Commission deny the CPCN without prejudice and allow Juno to refile its Application once it obtains a completed facility study. A completed Facilities Study would allow the Public Staff and the Commission to evaluate a reasonably known impact, estimate, of potential transmission upgrades to maintain the safety and reliability of the bulk electric system.

Juno is seeking to interconnect into a known constrained area of Duke Energy

Progress transmission system and sell the output of the facility to an offtaker in PJM. Duke Energy Progress has not completed a Power Flow Analysis or any other interconnection study and Juno's proposed condition fails to address the magnitude, or total cost, of the required upgrades to allow interconnection of Juno or a combination of multiple projects.

The Public Staff disagrees with the characterization of the Cluster Study process as a catch-22. It is simply a business decision that the Applicant has to make like other generating facilities participating in the Transitional Cluster Study, TCS, or Definitive Interconnection Study process, DISIS. The TCS is a voluntary process for the transition from serial studies to large-scale cluster studies through two state commissions and the FERC. Under the TCS process, which Juno has entered into, the Applicant does not need a CPCN to progress through the TCS process. Juno will have the opportunity to apply for a CPCN once the upgrade costs are known. Should that be a contested proceeding that impacts the timing to start construction of the facility, Juno also has the right to file a request of limited construction authority.

The Levelized Cost of Transmission metric, aka LCOT, is not a pass/fail test. LCOT is a factor to be considered, along with other factors, like the total magnitude of costs and potential impacts of a transmission system, a position that the Public Staff has consistently taken in testimony in multiple other merchant plant CPCN dockets. The need for the power in the state and the region must also be balanced against the cost and the long-term planning for the state as the Commission considers whether a facility meets the Public Convenience and Necessity pursuant to North Carolina General Statute § 62-110.1.

I listed in my testimony the Applicant's proposed condition of a $4.00/MWh LCOT rate impacts to North Carolina retail and wholesale. See my testimony Metz Table 2. While Table 2 is illustrative to see that the rate impacts of approximately 0.09 percent, North Carolina retail impact and a 2.29 percent wholesale impact, noting that this rate impact does not factor in the total magnitude of other projects that may seek interconnection in the first ever Transitional Cluster Study process. Fundamentally, Public Staff believes that the Applicant is seeking a certificate too early in the process. The Public Staff first proposed a stay until the costs are known. The Commission denied the request for a stay and we believe the next best alternative is denial without prejudice. Juno is the only merchant plant in the TCS seeking a CPCN at this early stage and we believe the Commission would be in a better position to evaluate the application once the interconnection study results are available from the TCS. This completes my summary.

MS. CUMMINGS: Thank you, Mr. Metz. The witness is available for cross examination.

CROSS EXAMINATION BY MR. SNOWDEN:

Q Good afternoon, Mr. Metz.

A Good afternoon.

Q So Mr. Metz, counsel for the Public Staff, in their cross-examination of Mr. Levitas and Ms. Miller, discuss some filings that were made before this Commission for FERC during Queue Reform. Do you recall that?

A Yes.

Q So they reference the -- this Commission's approval in the E-100, Sub 101 docket of Queue Reform?

A Yes.

Q And also FERC's order approving Queue -- FERC jurisdictional Queue Reform process; is that right?

A I'm generally aware of them, yes.

Q Okay. So would you agree that CPCN procedures for FERC jurisdictional projects were not at issue in the E-100, Sub 101 docket?

A That is correct. My general understanding of the Transitional Cluster process, whether it was the NCIP or the LGIA or the LGIP, the CPCNs was not a consideration. The consideration was how to transition the Queue.

Q Okay. And the changes to the procedures that this Commission considered in the Sub 101 docket related solely to state jurisdictional projects, right?

A That is correct.

Q Okay. And wouldn't you agree that FERC would have no business weighing in on issues related to the issuance of CPCNs by this Commission?
A I can't speculate on what FERC evaluated.
Q Okay. Well, would you agree that it's not within FERC's jurisdiction to rule on the procedures for issuance of a CPCN by this Commission?

MS. CUMMINGS: Objection. I don't think the witness should have to speculate on FERC's jurisdictional limit.

MR. SNOWDEN: Fair enough.

Q I want to ask you this. It's not the Public Staff's position that because the solar industry, CCEBA, supported Duke's Queue Reform proposals before this Commission, and before FERC, that Juno Solar should be barred from raising this Catch-22 issue in this docket, is it?
A My testimony is not preventing Juno from raising the supposed Catch-22 issue.
Q Okay. So it's not the Public Staff's position that CCEBA's support for the Queue Reform proposals prevents Juno Solar from raising what it believes is the Catch-22 issue in this docket; is that right?

A Are you asking -- sorry to ask a question on a question. I'm trying to seek clarification.
Q Sure.
A Are you asking what was discussed during the stakeholder process or are you asking what's --
Q Not --
A -- put on the application?
Q Not at all. I'm just trying to understand the Public Staff's position on this issue. Does the Public Staff maintain that because CCEBA supported and other members of the industry supported Queue Reform proposals, that Juno Solar shouldn't be able to raise this supposed Catch-22 issue in the CPCN docket?
A I mean, it's their application. They can raise what they want.
Q Okay. Thank you. So, Mr. Metz, you testified that you do not believe that Juno Solar has demonstrated a need for the facility; is that right?
A Could you point to exactly in my testimony?
Q Sure. I can point you to page 28 of your direct testimony -- your testimony.
A Thank you. One second. So yes. On the bottom

of page 8, after 14 -- lines 14 through 16, taking in context the entire question and answer, starting on line 4 through 13. Yeah. "Based on my review of the PJM Interconnection Queue, the Applicant has not demonstrated a need for the Facility or that it has to be located in a DEP service territory to serve PJM."

Q Okay. Well, let's take the first part of that where you say that the Applicant has not demonstrated the need for the facility. What's your basis for concluding that the Applicant hasn't demonstrated the need for the facility?

A Well, an emphasis that facility is upper case, so it's just saying the Juno facility specifically. Is that given the amount of carbon-free generation within the PJM queues that are reviewed, and other EMP applications, there are numerous amounts of other generation that can serve what PJM has identified as energy and capacity needs.

Q So what I'm hearing you say is that PJM's got -- there are plenty of carbon-free projects in PJM's queue, and so this facility is not necessary?

A I'm not saying it's not necessary. I'm just saying the amount of energy that could be procured could also be procured from other resources. It does not have to be solely from this project, this facility within the DEP service territory.

Q So because -- I'm trying to understand. So is it your position that because the Juno facility is not the sole viable source for carbon-free generation in PJM, there's not a need for it in PJM?

A I mean, I believe I stated earlier was that there is a need for energy and capacity in PJM; however, PJM has not identified that the only place that they can get it from is this facility or Juno Solar.

Q Well, PJM itself doesn't identify needs for capacity comprehensively, does it? I mean, it's a market, isn't it?

A It is a market. That is correct.

Q Okay. So would it be fair to say that it is buyers within PJM who identify needs for energy and capacity?

A I guess I'm getting hung up on a little bit on the context of the word "need". To the extent that if a buyer wanted the energy or capacity for their carbon-reduction goals, then it would facilitate a market decision.

Q Okay. So if there is a market decision to procure energy and capacity from this facility; would you agree that there is a need for the facility?

A Based upon my understanding of the Applicant and the non-binding -- being careful with this -- the non-binding agreement, that there is a need for carbon-free generation.

Q Okay. So it's your understanding that there's a need for carbon-free generation. Is there a need for this facility?

A I believe my testimony has answered this.

Q Okay. But you do agree that there is a demonstrated need for energy and capacity in PJM; is that right?

A That is correct.

Q Okay. So the Public Staff has considered CPCN Applications for a number of other merchant plants that plan to sell it to PJM. Are you familiar with those?

A Yes, I am.

Q Okay. So these would include the Timbermill Wind project in EMP-118; is that right?
A That is correct.
Q Okay. And that would include American Beech Solar?
A That is correct.
Q Okay. Just to name of couple of them. So would you agree that in each case where a merchant facility has announced its -- back up. Would you agree that where merchant facilities applying for CPCNs have stated that they intend to sell to PJM, in every such case, the Public Staff has either agreed that there was a demonstrated need for the facility or not taken a position on the issue? Do you agree with that?
A Yes. And we did not recommend denial of this facility based upon the need element. We recommended denial without prejudice based upon the facilities coming in too premature and the Public Staff would need to evaluate the transmission cost once the incumbent utility or the transmission owner, in this case Duke Energy Progress, completed their Power Flow Analysis.
Q Understood. And we'll get to that. But I'm

really trying to focus on your conclusion that there is not a demonstrated need for the facility.

Prior to this proceeding the Public Staff has never taken the position that a merchant plant selling into PJM has not demonstrated a need for that facility; is that right?

A I'm trying to go through the multiple EMPs through my head and specifically the ones that I filed testimony on but, subject to check, yes.

Q Okay. And the Commission has granted CPCNs to merchant plants that intend to sell into PJM, hasn't it?

A I cannot recall all the EMP applications, but yes, I do believe there are some.

Q And so would you agree that in the Edgecombe Solar case the Commission granted a CPCN based in part on the fact that Edgecombe Solar was planning to sell into PJM?

A Yes.

Q Okay. And the same could be said of the Fern Solar Application; is that right?

A Subject to check.

Q Okay. And the same could be said for the Halifax County Solar application; is that right?

A That is correct.

Q Okay. And more recently the Commission concluded that the Oak Trail Solar project demonstrated a need based on sales into PJM; is that right?

A Subject to check.

Q Okay. So in short, I mean, wouldn't you agree that in the eyes of both the Public Staff and the Commission up to now merchant plants selling into PJM have consistently been able to demonstrate a need for the facility?

A Up to now for the projects that have tried to sell into PJM have been located within the PJM footprint. So this facility created an existential wrinkle when it is a project trying to locate with Duke Energy Progress and then sell the energy into PJM.

Q Okay. Well, this is getting to something important. I'm trying to understand why in prior cases the Public Staff has always supported or at least not opposed a showing of need and in this case the Public Staff has come to the conclusion that there's not a need for the facility. And what I think I'm hearing from you is that there's not a need for the facility because it's located in DEP. Is that an accurate characterization of your testimony?

A No. An accurate characterization of my testimony on lines 14 through 16. *Based on my review of the PJM interconnection queue, Applicant has not demonstrated the need for the facility or that it has to be located in DEP service territory to serve PJM.*

Q Okay. So, is it your testimony or your view that you're not contesting that there may be a need for the facility's output in PJM, it's just that it hasn't shown that it needs to be located in DEP?

A That's a fair characterization, yes.

Q Okay. On what basis have you concluded that the facility needs to show that it must be located in DEP to serve that need?

A Well, in part of the evaluation I'll be looking at the overall transmission impacts to the system. So in this particular case, Duke Energy Progress through the FERC Crediting Policy, Duke Energy Progress ratepayers would ultimately be

responsible for any transmission upgrades that need to take place or their allocation through TCS accordingly. So again, this creates a unique circumstance when to evaluate the overall project.
Q Okay. So I think I'm hearing you say that your position on need is driven by the fact that Juno may trigger upgrades that would get reimbursed by DEP's ratepayers; is that right?
A Not solely, no.
Q Okay.
A But the facts and circumstances on specific applications that they are locating within Duke Energy Progress.
Q Okay. So is it the location of the project within DEP that drives your conclusion about the need for the project?
A Not in isolation, no. Or if the project was located within PJM, the project could direct sell to PJM just as the other EMPs that you have made mention of. And then the aspects of having to evaluate the transmission system, regardless of which utility is responsible for, may be somewhat minimized with the factor of Affected System

Studies of course.

Q Okay. Well, let me ask it another way. Why is -- why should the Commission care whether this facility is located in -- well, back up. With regard to the issue of need, what is the relevance of this project being located in DEP or in PJM if it can sell into PJM either way?

A I feel like I've answered this three or four times now.

Q Okay. Well, bear with me because I'm a slow learner. I'm -- sorry. Go ahead.

A It's just the application the Applicant Juno Solar did not demonstrate that in order to serve PJM's forecasted needs, it has to come from the Juno facility. And the Public Staff did not recommend denial based upon need. This is an observation.

Q Let me ask it another way. If there was no possibility that there would be reimbursable upgrades for the Juno project, would you have found that there was a need for the project?

A The Public Staff would still evaluate the transmission impacts regardless of whose cost responsibility they are.

Q All right. Ms. Miller testifies in her rebuttal testimony that Juno has executed a term sheet for a large investment grid retail and wholesale energy provider in PJM. Did you hear her testimony about that?
A Yes, the non-binding term sheet. Yes.
Q Okay. And you do not -- is it your position that having executed a non-binding term sheet does not demonstrate need for the project?
A It's non-binding. It can change.
Q Okay. Are you familiar with the Timbermill Wind project which is currently seeking a CPCN in Docket Number EMP-118, Sub 0?
A Mr. Thomas was the lead engineer from the Public Staff. I'm generally familiar with the overall application, but not the specifics of it.
Q Are you aware that in that case the Public Staff found that there was -- found that there was a demonstrated need for the project even though the project did not have a contract for the sale of its output?
A I would have to defer to the testimony of what's in the record.
Q Okay. So in her rebuttal testimony Ms. Miller

testifies about the transmission charges that Juno Solar will have to pay to wheel its output in PJM and did you hear the testimony on that this morning?
A Yes, I did.
Q Okay. And merchant projects that are located in PJM do not have to pay those charges to DEP, do they?
A So if a project is located within PJM and they are not wheeling through Duke Energy Progress, then no, they would not pay Duke Energy Progress a wheeling charge.
Q Okay. Thank you. And even if projects in PJM triggered upgrades, affected system upgrades, on Duke's system, they still wouldn't have to pay transmission charges to Duke; is that right?
A If your question was they would not have to pay wheeling charges, that would be correct, because in terms of an affected system depending on how everything going on with American Beech and the appeals --
Q Right.
A -- and all that and Duke's owed reimbursement they could pay the transmission costs pending the

outcome of that appeal. But the wheeling charge, there would be no wheeling charges.

Q Well, they could pay the costs -- the upfront costs of those upgrades; is that right?

A The -- so clarification, if we are talking about the affected system element of a PJM project into an affected system on Duke Energy Progress with an executed Affected System Operating Agreement which has the milestone provisions within it, the Applicant would pay Duke Energy Progress those costs and after commercial operation and upon mutual agreed upon terms between Duke Energy Progress and the Applicant in that case, there would be a reimbursement or is my understanding a potential transmission credit.

Q Okay. Thank you. But no wheeling charges of the kind that Juno is going to have to pay to Duke; is that right?

A That is correct.

Q Okay. So Ms. Miller testified that Birch Creek projects that Juno will pay more than $275 million in wheeling charges to DEP over the life of the project. Would you agree that those revenues provide a benefit to DEP and its ratepayers?

A So the wheeling charges and the wheeling charging revenues or through the ATRR revenues is slightly complex. I'm going to try to answer it the best of my abilities from an engineering perspective. I'll infer the Commission had further questions from an accounting perspective, that the Public Staff would make those resources available or even Duke Energy's. I am not an accountant. I get a little bit lost in the revenues and how they flow, so I'll try to answer it to the best of my abilities.

So through the wheeling charges the one element that created some difficulties in calculating it -- well, first and foremost, the Public Staff initiated discovery on this because we thought there would be or could be a revenue to ratepayers to potentially apply against or offset the LCOT. So this was initiated just like we do in avoided cost. We try to find increments and decrements, because we all know the interconnection process continues to evolve. So there's an understanding of the overall process. So we evaluated the wheeling charges and sought discovery from the Applicant on this matter.

So one element that started to create some complexity in evaluating this was the optionality of the project. As we heard today it's like well, on one hand they could sell into PJM. Well, under that hypothetical I'll come back to non-firm and firm because there is a cost difference and that can be found on Duke's OASIS website publicly available.

How do we start evaluating that? Under what revenue stream? Can I say right now that if an applicant proposed optionality it'll be on a non-binding agreement but we could do something else with it later or any point up to execution I found it extremely difficult to -- not the calculation itself, but probably the weight that that would actually be a revenue offset to overall calculation. So just optionality in itself created difficulties summarizing.

Moving to the second point versus firm versus non-firm. I believe we've heard reference to Public Staff Data Request 213, and using the spreadsheet that the Company provided and that they listed 175 MW of what they were prescribing -- prescribing -- not that they have to do it, not that a Conditional CPCN can make them do it -- of 175 MW and they're able to calculate the firm point-to-point service. So yes, using the Company's spreadsheet and before I start -- it's nonconfidential, correct? I believe we've released it, but I heard something conflicting.

Q Yes. Yes.

A Okay.

Q It's nonconfidential.

A And we can -- I can provide this to the Commission as a late-filed exhibit as well with some of the Public Staff calculations. Under 175 MW firm point-to-point, firm being that they are subscribing that they have rights to move that energy across Duke Energy Progress systems and cannot be curtailed unless probably under emergency conditions, under 40 years, yes; $286 million in potential revenue at the escalation rates projected and all assumptions held constant.

However, one would have to

evaluate the net present value of that. In other words, ratepayers today under a $4.00 LCOT would be $51 million. You would have to do a net present value of the potential revenues over 40 years. Going out 40 years there is a lot of assumptions. It's a lot of unknowns. I'll stay away from the word risk. Simplifying discount rate, that equates to $88 million net present value with 175 MW firm point to point. Again, to restate, I could not give that any weight given the optionality of the project.

A different evaluation that I conducted was that revenue stream from the wheeling charges was not with the upgrades of a $4.00 LCOT. One would need to add in the potential of the $4.00 LCOT which would be $51 million, and so under the initial case would be the base case and then one would evaluate the additional $51 million injection at year one, simplifying assumptions, and doing a Net Present Value Analysis it went to instead of $88.2 million it went to $89.7 million plus or minus. There's some assumptions in here.

The base case in change case

demonstrated that only $1.5 million additional revenue would be from the $51 million upgrade cost or approximately one-sixteenth. Again, increment and decrement that the Public Staff has evaluated consistently in multiple dockets.

The second part of the evaluation was looking at the non-firm, because again, the Application as proposed did not say whether it had to be firm or non-firm. The Applicant could elect to do non-firm. Using the same assumptions of 40 years -- and by the way, I've done this at 15 years, 20 years, and 30 years -- the simplifying assumptions with non-firm the revenues drop in half to approximately $42 million versus the approximately $88 to $89 million.

I know it's a little bit long-winded answer, but on the wheeling charges, it was a lot to discuss there and the conversation.

Q Yeah, I'm forgetting my question.

COMMISSIONER DUFFLEY: And Mr. Snowden, while you think of that, if you will provide a late-filed exhibit. Thank you.

MR. SNOWDEN: Certainly.

BY MR. SNOWDEN:

Q Let's unpack it. There are a couple of things to unpack in your answer there. The first thing that stood out to me was that you said that you calculated based on Juno's allocation, their statements about the purchase of firm transmission, that the net present value of that $275 million or so would be either $88 million or $89.7 million; is that right?

A Approximately with the given discount rate add 40 years if all things manifest themselves.

Q Okay. So that is higher than the 50 or so million dollars in upgrade cost that would correspond to the $4.00 LCOT; is that right?

A That is higher with the caveat that that is under assumption that they would do firm point-to-point service or non-firm point-to-point service over the entire contract length, that they could elect at a different point in time say at 15 years or 10 years, again, because it's a non-binding term sheet, a different term sheet can be elected into tomorrow. I can't speculate on that nature. But yes, that why I evaluated at different term

lengths.
Q Do you have any reason to doubt that they would continue to purchase firm transmission service over the life of the project?
A Well, I heard today that -- I thought I heard today that you would evaluate potentially selling the -- well, I read in the Application that your evaluator even in through discovery that you could sell at anytime to Duke Energy Progress as an offtaker or outright sell the facility to potentially Duke Energy or Duke Energy Progress. So yes, I do have reason to doubt.
Q Okay. But would you agree that if the project were sold to Duke for compliance with -- for purposes of meeting the H.B. 951 goals, that's just an entirely different set of benefits that we'd be looking at, isn't it?
A That is and that's a great question, because under that we would no longer -- ratepayers would no longer be receiving the wheeling revenue to potentially offset the transmission costs.
Q Okay. I also want to go back to something else you said. You calculated that out of the $88 or $89 million in wheeling charges, only $1 million

or so of those charges would go to paying for the upgrades associated with the facility; is that right?

A Under one scenario looking at the potential, if you would look at the incremental contribution, under that concept then yes, it would only be $1.5 million, but there are multiple assumptions embedded with that and that may not be the most absolute value to hang your hat on.

Q Okay. But some portion of the rest of that would go to fund other -- either other upgrades to Duke's system or other capital investments past or future in Duke's transmission system, wouldn't it?

A And that -- and that is true. And with the further clarification is that not just all of the costs through the OATT or for capital. I do not know the percentages, but they are O&M, overhead, and other capital expenditures.

Q Okay.

A And capital expenditures.

Q Okay. Projects that are located in Duke's service territory that sell to Duke do not pay transmission or wheeling charges to Duke; is that

right?
A Can you say that again, please?
Q A project that is located in Duke's service territory and that sells to Duke does not pay wheeling charges, right?
A It is my understanding if a facility hypothetically is located in Duke Energy Progress and direct sells to Duke Energy Progress, then no, there would be no wheeling charges.
Q Okay. Thank you. So Juno Solar has requested that the Commission approve its CPCN subject to a condition that if the LCOT upgrades associated with the project exceeds $4.00 per MWh the CPCN will terminate. Is that your understanding?
A Yes, that is my understanding.
Q Now, in your testimony you do not take any position on the question of whether an LCOT of no more than $4.00 per MWh is reasonable, do you?
A I do not take a position, because the position of my testimony was is that in order for me to provide a recommendation to this Commission that I need a completed Facility Study with best estimate transmission cost from the transmission owner in order to make the evaluation. Noting

that even those costs like we saw in Friesian, like we've seen in other EMP applications where I filed testimony, those costs go up and down through multiple times and even as we had in discovery in this particular case on your project, Public Staff Data Request Number 2 looking at question number 7 we asked the question "What class or level estimate would Juno consider the $16.84 million estimate. What is the tolerance and range of that estimate."

This is a planning or budgetary class estimate based upon the reasonableness and assumptions in line with the Utility Practice and Industry Standards. This estimate is to have a minus 20 plus 100 variation. These -- again, these are still preliminary estimates.

We accept that there are estimates, but however, like I tried to say and we said in testimony I need a completed Facility Study from the utility noting that we will have to evaluate those costs at that time and understanding the risks associated with some of those potential upgrades and the level of class estimate. And like I've done in other EMP testimonies, that we will evaluate a range of potential outcomes of magnitudes of cost to evaluate the benchmark and reasonableness on the LCOT metric which is inclusive of evaluating the magnitude and the nature of the upgrades in themselves.

Q Isn't Juno Solar asking in this case that the ultimate fate of its CPCN will be determined by the LCOT as shown in the Facility Study for the project?

A So the Applicant is requesting and through, I believe, different clarifications of testimony because the position has morphed over time or evolved slightly that the Applicant is agreeing that $4.00 LCOT all-in cost is the -- it will -- if it goes over that, then they'll withdraw or revocate their CPCN. That is my understanding of the Applicant's request.

Q Okay. And is it your understanding that Juno is not asking the Commission to make a judgment as to what the actual LCOT of the project is based on its current estimates, is it? Let me ask it another way. Juno has asked that the Commission set a $4.00 standard for LCOT for the project, right?

A That is correct.

Q All right. And compliance with that $4.00 standard is to be measured based on the results of its Facility Study; is that right?

A I don't know if it was designated that the Facility Study would be actually setting the benchmark as pass or fail, because that creates another unique issue with the termination provision as proposed and the conditions somewhat become -- it's not -- problematic is not the right word. It's just becomes very complex to try to solve for to the extent that the Applicant is requesting that the execution of the Interconnection Agreement should terminate the revocation provisions through time and other factors where estimates change and those costs could go up.

Q Well, let me ask you this though. You are not taking the position that the Commission should be able to revoke a CPCN based on what the, you know, post-construction actual costs of interconnection are, are you?

A No. I'm saying at this time if we looked at the timing of it, again, we do not have a completed Facility Study with a level or range of estimate or evaluation of even what the upgrades are, I would have to evaluate the upgrades, the execution of the Interconnection Agreement and the types of upgrades, because I remember testifying to this on Friesian, and part of the conversation was the multiple river crossings associated with Friesian. Each river crossing from a project management standpoint and a construction standpoint is an embedded risk. I can't make an informed decision on whether or not the terminating provision should indeed be the IA with the balance of the actual estimation, because until you put boots on the ground, you don't know what you're going to run into.

So, if we did a paper version of an evaluation that based LCOT off of and the metric and all these conditional functions that we want to, that the Applicant is trying to request, one may need to evaluate whether that is appropriate in that unique set of facts and circumstances.

Q So are you telling me that you don't necessarily trust the estimates that are prepared by Duke's interconnection teams for purposes of the Interconnection Agreement?

A That has never came out of my mouth.

Q Okay. Well, that's -- I mean, that's -- I'm asking you -- what I think I'm hearing you say is that well, you know, there's a lot of uncertainty with these IA estimates. You know, Duke's teams may not have appropriately accounted for risks. I would need to review that myself to determine whether that estimate is reliable. Is that your testimony?

A As I'm representing the general and consuming public, yes.

Q Okay. So if you had an Interconnection Agreement in your hand that said the cost of these upgrades is however many dollars equals a $4.00 LCOT, even at that point the Public Staff could not reach a conclusion as to whether the LCOT for the facility was reasonable?

A It starts to become very challenging, because, for example, if the $4.00 LCOT -- so I believe the testimony listed that approximately the Applicant through their Power Flow Analysis estimated that around 17 miles of transmission line will have to be upgraded. I mean, we have seen in other system impact studies within PJM on new EMP applications triggering what they call wreck and rebuild that basically we could have just invested millions of dollars, hundreds of thousands of dollars, who knows what the cost are on a line for reliability upgrade last year, two years, five years, et cetera, but then a project comes on and says hey, we need to wreck and rebuild that not for reliability, because the existing system is okay, it's working, it's per NERC standards, and we need to rebuild that line so ratepayers may be exposed to the undepreciated cost of the existing line plus now the incremental cost.

So again, one needs to evaluate exactly what the transmission upgrades will or will not be.

Q It sounds to me like you're testifying that you don't think that -- well, is it your view that LCOT is not a particularly good metric for the reasonableness of interconnection cost?

A I believe it was stated earlier is that LCOT was

just one tool in the evaluation of a project.
Q So, in the Friesian docket you provided testimony about what you thought were appropriate benchmark LCOT values for network upgrades in that case; is that right?
A If you're referencing the LBNL Study, that is correct?
Q Okay. And the LCOT values from the LBNL Study were in the range of $1.56 to $3.22 per MWh; is that right?
A That's sounds correct, yes.
Q Okay. And would you agree that since 2019 transmission costs have generally risen?
A Generally risen is somewhat vague. Just looking at markets and potential labor cost and other there's been more upward pressure with them the last year. But yes, I would agree they have generally risen.
Q Okay. So let me ask you this. Would you agree that as of now an LCOT of $4.00/MWh is not unreasonably out of line with those LCOT figures that are presented in the LBNL Study?
A That is correct. The Public Staff does agree that the potential of a $4.00 LCOT may be the

correct metric, but however, until we see a completed Facility Study from Duke Energy Progress specific to Juno Solar, it's premature to just say that's okay. Because what -- one function of the LCOT -- well, how people are characterizing the LCOT we're failing to identify the magnitude cost impact.

For example, a 5-MW project with an LCOT of $4.00 has a much lower impact to wholesale in North Carolina retail compared to a 275-MW project. And as we can see through the TCS cluster that is potentially coming through, there's going to be a magnitude of projects knowing that at this point in time we're only seeing the potential of one CPCN, we have to evaluate the magnitude of cost.

Q So Mr. Metz, what I'm hearing is that you are concerned with the overall magnitude, not just the -- what I'm hearing is that you are concerned not just with the LCOT from the project, but one of the other factors you're concerned about is the -- is the magnitude of -- the absolute magnitude of the upgrades associated with that project; is that right?

A That is just another element, yes.
Q Okay. And has the Public Staff taken a position as to what absolute magnitude of upgrades associated with a single project would be reasonable or unreasonable?
A No, because I tried to clarify that earlier on. Okay. So it's also an embedded function of what the upgrades actually are. So, for example, if under one hypothetical if it's a wreck and rebuild of a new line we just got done building, we would need to take that into overall consideration.
It may not be a failing criteria. It may not be a passing criteria. It's just something that has to be taken into consideration. And these transmission studies are -- and these projects are all unique in nature.
Q Let me ask you this. In prior merchant plant CPCN dockets, has the Public Staff taken a close look at the exact nature of the upgrades at issue when in his recommended approval of those CPCNs?
A One second. So it might serve the Commission that we answer this question in a data request

from the Applicant in DR-1. Specifically question 8. Question 8, "Public Staff witness Metz states that the Commission cannot make a full informed decision on the application until it's been studied." Fast-forwarding. "Please identify all CPCN proceedings including applications for utility constructed facilities in which the Public Staff has taken a position that the Commission should not render a decision."

So in that response I go through each one of the applications inclusive of EMPs and utility-owned generation. I'm not going to reread it. I mean, we're happy to provide the Commission this response unless they want me to go in more detail in each one of the dockets.

Q Looking at these --

COMMISSIONER DUFFLEY: Mr. Snowden, if I could interrupt. We would like that in a late-filed exhibit, please.

MR. SNOWDEN: Actually Commissioner Duffley, I can go ahead and request that this data request be marked for identification as Applicant's Cross Examination Exhibit 1 --

COMMISSIONER DUFFLEY: So marked.

MR. SNOWDEN: -- so we can all see it. Yeah.

COMMISSIONER DUFFLEY: And let's mark that Metz Cross Examination --

MR. SNOWDEN: Yes. Yes, ma'am.

COMMISSIONER DUFFLEY: -- Number 1. And then looking at how we've marked the Public Staff we'll call it the Juno Metz Cross Exhibit Number 1 to keep consistent with the Public Staff records.

(WHEREUPON, Juno Metz Cross Exhibit 1 is marked for identification.)

BY MR. SNOWDEN:

Q So Mr. Metz -- has everybody got a copy of that now? Looking at the Public Staff's response to Data Request 8, there are several dockets here. With the exception of the EMP-92 docket, these are all dockets relating to CPCNs for utility constructed or units; is that right?

A That is correct.

Q Okay. And would you agree that the utility has got a much greater access to information about the nature of the upgrades that would be required for a facility than an interconnection customer does?

A Well, I mean an interconnection customer once they have a completed System Impact Study and a Facility Study from the utility, they should have a degree of insight into the overall upgrades. My apologies. I am looking for the EMP applications -- exactly.

So, on page 12 of my testimony, we also go into great detail especially footnote 9 of the multiple EMP applications, so my apologies, Mr. Snowden. I only answered the utility-owned but not the merchant plant aspect in the previous question.

Q Okay. Well, I was just asking about the utility-owned ones. So referencing your footnote 9 here on page 12 of your testimony, that references instances in which the Public Staff has requested that additional information about costs, network upgrade costs be provided to the Commission; is that right?

A That is correct. And as you can go to the PJM website on each one of those individual EMP applications, you can see the completed --

there's three studies on -- forget the first one, it's FC, but then System Impact Study and then the equivalent Facility Study.

And some of the conversations that we've had in the previous EMP applications especially EMP-102, Sub 1 which is before this Commission that was my -- there's been multiple filings in that testimony, so I lose track of which one, but at one point in that time is the Public Staff could not make a recommendation similar to Juno Solar is that we did not have a completed Affected System Study for the second part of the overall project, which is in my opinion almost identical to what is going here before Juno. We just cannot make a recommendation on a cost that we don't know what it is or the nature of the upgrades that we don't know what it is.

Q So you believe that the Commission needs to have complete information about all the upgrades that will be required for a project before a CPCN can be granted?

A I believe a Facility Study is the utility's best effort to provide insight in the nature and the cost of the upgrades.

Q Okay. So Mr. Metz, you also say in your testimony that it's the aggregate cost to ratepayers of upgrades in the Transitional Cluster Study that's important. Is that a fair characterization of your testimony?

A I don't know if I said important. If you can point to the point where you're referencing.

Q I'm afraid I don't have a citation off the top of my head. Would you agree that your -- that you testified that the Commission must consider the aggregate cost of all the upgrades triggered by the Transitional Cluster Study before it can act on Juno's CPCN?

A Similar to when I was looking at the on impact to rates on page 30 on Table 1 and then the results on Table 2, I believe the Public Staff would and I believe the Commission would also evaluate the total rate impacts in whole. So when one evaluates certain particular projects, the rate impacts could go up and in other circumstances they may not.

Q Okay. So let me ask you this, because I'm trying to understand how this is going to work. Or how the Public Staff sees this as working. So, if a group of projects in the Transitional Cluster were to collectively impose upgrade costs that the Public Staff believed were unreasonable, should the Commission just deny CPCNs for all of those projects?

A I mean, the answer would be no with a caveat that that's sort of an open-ended question, because I would have to know the nuances or the specifications of each individual project. For example, if they are state-jurisdictional projects seeking CPCNs and interconnection through the TCS, those costs would not be borne by ratepayers. They would be borne by for lack of a better word the market participants or the individual investor.

Q Well, let's limit it to just FERC-jurisdictional projects that whose upgrade costs might be reimbursed by ratepayers. So a group of FERC-jurisdictional projects in the Transitional Cluster collectively resulted in upgrades that the Public Staff thought was unreasonably large in the aggregate. What should the Commission do with that information? Should it deny CPCNs to all the projects that it has before it?

A One would have to evaluate the overall project, because under that potential hypothetical, that is the assumption that all the projects are independent. There could be example -- there could be, again, hypothetical that there may be non-project interdependencies to projects on opposite ends of the system or even near part of the system depending on the injection of where they're putting on at part of the system at a given time. It could be not interdependent and they could be viewed in overall isolation.

But again, in DEP for North Carolina there are two FERC-jurisdictional projects and only one is seeking a CPCN right now before the Utilities Commission.

Q So, what I think I'm hearing you say is that this Commission in considering whether to grant a merchant plant CPCN should undertake to review not only the cost, but the complete nature of the upgrades that might be triggered by a proposed merchant plant; is that right?

A It should be taken into consideration, yes.

Q And that the Commission should also review not

only the aggregate cost, but the interrelationships among the different projects that might all trigger upgrades in the same cluster; is that right?
A It is a potential, yes.
Q That seems like a lot of work. Is that --
A But before is it two projects and Duke Energy Progress seeking FERC-jurisdictional interconnection. I don't know how to classify that as a lot of work.
Q Well so let me ask you a follow-up question. Speaking of the aggregate amount of upgrade costs that might be imposed in the Transitional Cluster, is there a number -- is there a cost -- an aggregate cost number that the Public Staff would deem unreasonable for upgrades coming out of the TCS?
A Could you clarify on -- again, as I stated earlier, when you're looking SP projects, it's done under a slightly different lens comparative to --
Q Just -- I'm sorry. Just for jurisdictional. Ignore the SPs. We don't care those right now.
A Thank you. So could you repeat the question,

please?

Q Yeah. So solely with regard to FERC-jurisdictional projects, upgrades that might be ultimately charged in part to North Carolina retail ratepayers, is there an aggregate number that the Public Staff would consider to be too much to be unreasonable?

A Well again, we believe the concept of the LCOT is correct in nature and it is a possibility once we have the completed Facility Study from Duke Energy Progress that even the concept of a $4.00 LCOT may be approved. I just -- I cannot make that approval at this point in time, because again, one has to evaluate the facts and circumstances at that particular point in time for that particular application or as to the possibility of a Cluster Study process one might need to, in fact, take a step back and look at it more of a holistic evaluation explicitly when we're starting to look at potential outcomes of the carbon plan that will be implemented in the coming years.

Q Okay. All right. I want to think about the logistics of requiring a Facility Study before a

merchant plant can submit a CPCN Application. So Juno is interconnecting under the OATT, not the North Carolina NCIP, right?
A That is correct.
Q Okay. So under the OATT, the LGIA, the Interconnection Agreement, has to be delivered to the customer within 60 days after receipt of the Facility Study; is that right?
A Subject to check. I've read over the LGIA. I don't have --
Q You haven't memorized it?
A I have not memorized it. I have reviewed it. I have aligned the time periods between that NCIP, but subject to check.
Q Okay. Thank you. I had to reread it last night, so I have not memorized it either. So in the Transitional Cluster the customer has to execute the LGIA within 60 days of receiving the draft IA; is that right?
A Subject to check.
Q Okay. So the customer has a total of 120 days from delivery of the Facility Study to execute an Interconnection Agreement?
A Up to, yes.

Q Okay. Up to. And signing the Interconnection Agreement obligates the customer to pay the upfront cost of interconnection facilities for the project and also upgrades; is that right?

A The executed LGIA -- yes, it's an agreement between the utility and the Applicant, right. Lose track of, because I've been spending a lot of my energy here lately on affected systems, I don't know if FERC has to approve that. I don't know.

Q If you -- I'll represent that if you use the pro forma, it just has to be filed not approved.

A Okay. Thank you.

Q All right. So, it's the Public Staff's position though that the Commission deny the Juno CPCN without prejudice and that Juno not be able to refile its application until after it has received its Facility Study and also any Affected System Studies; is that right? And I can direct you to page 6 of your testimony if that's helpful.

A Can you point to exactly what line?

Q Sure. So on lines 5 through 9. You say "I recommend that the Commission deny the CPCN

without prejudice allowing the Applicant to refile its application once it has obtained its Facility Study report and once any applicable network upgrades assigned from Affected System Studies are known." Did I read that correctly?
A That is correct --
Q Okay.
A -- because that will enable me to initiate the investigation process to evaluate the upgrades, the nature of upgrades, have conversations with the impacted utility and as well as the Applicant, similar to how we had conversations in discovery in Friesian.
Q Okay. So as we discussed under the OATT a customer has 120 days from the issuance of its Facility Study to execute its IA; is that right?
A Up to, yes.
Q Okay. In your experience it is typical for the Commission to issue a ruling on a merchant plant CPCN Application within 120 days of it being filed?
A I'm not cognizant of the dates on --
Q Okay. Well, have you -- do you recall an instance in which the Commission has granted a

merchant plant or has taken action to deny or grant a merchant plant CPCN within 120 days of it being filed?

A I'm not cognizant of the dates, but I'm trying to understand the relationship between the execution of the LGIA versus the CPCN. Those are -- while I know it's making a linkage, they don't have to be on the same track.

Q Okay. Well, let me ask you this. It's not really practicable for an interconnection customer to get its Facility Study, prepare a CPCN Application, file it and get a ruling from the Commission on its CPCN within 120 days, is it?

A I think it was something that had to be taken in consideration then the Applicant could make notification to the Commission to take into consideration not for an accelerated timeline, but a concept of potential priority given whatever is before the Commission at that time.

Q So you could ask for a ruling within 120; is that what you're saying?

A That's correct.

Q Okay. But --

A And I think this is a dynamic function of the TCS process, something that we're still learning through.
Q But there's not a process in place that would allow a merchant plant to get a CPCN approved or denied within 120 days, is there?
A I would have to go back and reread. I don't know if there's a timeline that's preventing something to be truncated. I don't think it says that you have to wait 180 days until you get a ruling.
Q Well, the Commission has got to -- there are certain specified timelines such as the 10-day completion deadline, public notice periods, clearinghouse review, time for testimony, time for hearings if necessary, and all that, right?
A That is correct.
Q Okay. And it's more typical for a CPCN Application to take at least say six months or more than that. Is that a fair characterization?
A Potential or one-off anomalies, but usually those were mandated by law.
Q Okay. So it seems to me extremely unlikely that if a merchant facility were not to file -- weren't able to file its application until after

it got its Facility Study, then it would receive a ruling on a CPCN prior to entering into its IA. Would you agree with that?

A Generally, I agree. And then when looking at the statement on page 6 and turning over to page 4, footnote 29, sort of laid out the timeline here for this very concept. When one looks at the issuance of the Facility Studies and the potential individual restudies throughout the process, one can see that the multiple 150 day blocks along with perspective timelines which if the LGIA takes up to 120 days, 120 days is well within the 150 days.

Q Okay. I'm sorry, Mr. Metz. I did not catch where it is that you're looking.

A Oh, sorry. Page 34, footnote 29. So through that footnote where it was generally laying out for illustrative purposes the CV, the different times of when study reports would be issued, the potential complexities of restudy, but in each circumstance the window opened for each individual one. We believe it was appropriate that even given with the up to 120 days that there would be time to perform this process under the nature of the TCS process, which was to clear the logjam. I believe it was said today it was to remove the speculative nature of certain projects and advance commercial-ready projects.

Q Okay. But I'm looking at footnote 29. There's no reference to the deadlines for executing an IA here, are there?

A That is correct. There is not.

Q Okay. This process you've laid out ends in Facility Study, right?

A The individual -- so about -- individual facility studies 150 days. September 27th, 2022 through February 24th, 2023. The issuance of facility studies and again, in conversations with Duke, this is sort of the back end if you would. This is sort of the up to. It may be issued before. And then Phase 3 restudy with the additional timeline requirements.

Q Okay. So you're saying Juno come back in maybe February of 2023 and file their application then? Is that right?

A Give or take upon the issuance of a Facility Study, yes.

Q Okay. So upon receipt of an application for CPCN

for a project that may have already signed an LGIA, the Commission could decide to deny that application, couldn't it?
A The Commission could or it could accept.
Q Okay. So fundamentally, the interconnection customer, the merchant facility, does not know whether the Commission is grant or deny its CPCN when it files its application, right?
A That is correct and I can't make my recommendation to the Commission until I see that actual Facility Study cost by the incumbent utility.
Q Okay. So is it your belief that a merchant facility should enter into an LGIA and commit itself to funding millions of dollars in upgrades and interconnection facilities without knowing whether this Commission will allow it to be constructed?
A So there's two concepts here. It's the TCS process and there's what comes after a TCS process which is often is referred to as the DISIS. Again, the TCS process and the milestones and the increased payments were completed through a negotiated stakeholder process which TCS

process had higher costs comparative to DISIS for the concept of as the word that's been used today clearing the logjam to remove the degree of speculative projects and move forward commercial-ready projects. That was all agreed upon through the stakeholder process by two commissions -- two State Commissions and the FERC.

Q Okay. I'm going to ask my question again, because I'm not -- I'm not sure I heard the answer to it. Is it your belief that a merchant facility either going through TCS or going through DISIS should enter into an -- should be required to enter into Interconnection Agreement without knowing whether the Commission will allow it to be constructed?

A That is a financial risk of that Applicant.

Q So yes?

A They have to evaluate the costs or the cost uncertainty at that given point in time.

Q Okay. So you --

A And I can't speculate on what the Applicant would or would not do, so I apologize. I'm not trying to dodge your question. It's just I can't say what the Applicant would or would not do in execution of LGIA. It's just one has to evaluate the knowns and unknowns and that's in my -- in my opinion a business risk that the Applicant would need to take whether they want to execute the LGIA.

In theory, in speculation, one could enter an LGIA and while waiting for the facility study, if they have a strong understanding of what they believe their transmission costs are, they can enter what they want to enter into. I can't control that.

Q Okay. But in the absence of guidance from the Commission or the Public Staff on what level of costs are reasonable, does a -- how does an interconnection customer make a decision whether or not to enter into an LGIA when they have no idea whether their CPCN is going to be granted or denied?

COMMISSIONER DUFFLEY: Mr. Snowden, that's been asked and answered --

MR. SNOWDEN: Okay. Okay.

COMMISSIONER DUFFLEY: -- a couple of times.

BY MR. SNOWDEN:

Q Well, let me ask you this. Mr. Metz, so when an LGIA is executed, the Utility's interconnection teams will commence doing engineering work and procuring long lead time materials and ultimately constructing the facilities and upgrades; is that right?

A Per the Milestone Agreements. For example, one of the items that we noticed in Friesian was the multiple years it would take for the construction in certain not credibly -- not critical energy infrastructure, but just critical parts of the system that can only be worked on during certain parts of the season. So that would have to be a factor in that agreement would be the timeline.

Q Okay. So Duke's personnel should go ahead and commence work on interconnection without knowing whether the project will actually go forward?

A That is a business risk that the Applicant will enter into with the incumbent utility. That is a business decision between those two parties.

Q Okay. Do you think that is a good use of Duke's limited construction resources?

A If the Milestone Agreements are to keep Duke

Energy cost neutral -- when I say cost neutral, is they will not expend "X" amount of cost or resources without being reimbursed. That is a risk-based decision to keep them indifferent.

Q Okay. Understood that Duke may be indifferent to the cost, but would you agree that Duke's own personnel and resources are not infinite?

A That is correct.

Q Okay. And that there is, in fact, a bit of a crunch on Duke's engineering and construction personnel and has been for the last several years?

A I can't define crunch, but I also know there's been increase in staffing to address these potential situations.

Q Okay. Is it your understanding that once an IA is signed, subsequent DISIS clusters will rely on upgrades that are committed through an IA in the baseline for the next study?

A I'm just trying to -- I'm trying to go through my mind as saying okay, is the baseline the actual IA, because a function of the baseline is the base case which is already considering future upgrades that are already in the works. So it's

not solely based upon the IA. I do not know --
Q All right.
A -- if it explicitly encompasses the IA or not.
Q Well, let me ask it another way. Say you've got the DISIS 2023 cluster and Duke is establishing the base case for that. It's going to consider upgrades that were allocated and committed in the DISIS 2020 -- in the previous year cluster, right?
A Yes. A function of the future DISIS would always be the base case of the -- trying to get my vocabulary right here -- of whatever the entered-in contracts with the previous cluster agreed to pay for.
Q Okay. So wouldn't it cause some pretty significant disruption to other interconnect customers if the Commission were to deny a CPCN for a project that had already signed an IA?
A It depends. It's -- again, it's very complex in nature, because you can have some projects that will not -- again, in theory, you'll have some projects interconnecting in parts of the system that would not have any upgrade costs or create the interdependencies under some examples with

multiple interdependencies. Depending on the magnitude of the interdependencies, there could be complications, but again, complications are just challenges that we continually work and overcome on every given day.

Q Okay. Well, let me -- I'm going to narrow the question a little bit. Take as an example a project that does have significant interdependencies and does incur significant upgrade costs, because I think those are the kinds of projects that, you know, we care about or that the Public Staff cares about.

Wouldn't it be pretty disruptive other interconnection customers into the DISIS process if the Commission were to deny a CPCN for a project like that after it had already signed an IA?

A But again, as I stated earlier, I believe that there's a -- there is enough of a window for once the Facility Study costs are known, they can be evaluated and be brought forward to this Commission and potential for the Commission to make their ruling on whether it should be denied or accepted prior to the next DISIS window closing. Because there is a -- when the DISIS window is opened, there's a period of time before the DISIS window closes.

Q Well, let me ask this. Say you've got -- and I'll move on, because I know we've spent a long time on this. Wouldn't it cause a lot of disruption to the same cluster that the project was in if the Commission were to later deny the CPCN assuming, again, that the project had significant interdependencies and committed to constructing upgrades?

A That's a risk with Cluster Studies process and with functions being interdependent. I mean, we're seeing that right now in PJM, so that is not a new process. That's something that already exists.

Q Understood that the risk of project withdrawals is part of a Cluster Study, do you think the Commission should be doing things to increase the risk of disruption based on more withdrawals?

A I don't believe that we are increasing the risk, because again, as I stated before, is in order for me or the Public Staff and presumably the Commission to make the determination of what the transmission upgrades are mean a completed Facility Study looking at the timelines there is an adequate window albeit somewhat narrow to potentially resolve this issue.

Q Okay. So you say there is an adequate but narrow window after the delivery of the Facility Study to evaluate those costs; is that right?

A Yes.

Q Okay. But you also recommend that Juno not refile its application until after an Affected System Study -- certainly an Affected System Study is completed; is that right?

A That is correct and that's one of the concerns that we did bring up during the stakeholder process as well in our comments that we filed is that the Affected System Study is somewhat -- it's not isolated, but it is in its own parallel path without explicit timelines. So as the Applicant moves through its process, an example, if a project goes into Phase 1 and they get identified of their, hypothetically, locating a Duke Energy Progress and under an affected system under Phase 1 Duke Energy Progress will notify DEC, hey, you're an affected system. What do you want to do about it?

So through the LGI process, Duke Energy Carolinas will say all right, we're going to go evaluate it while the transition cluster and DISIS are moving forward at their own pace. I mean, some of this has also been brought up in much detail due to the resource solicitation cluster. It's that Duke Energy Carolinas could notify them to say well, while you triggered an affected system, there really wasn't nothing there; it was no cost or it was something very, very nebulous.

However, what the Applicant is also informed on both of Phase 1 and phase 2 it's a flag. It's a risk. You have the potential for affected system upgrades. With that known risk, do you want to continue to move forward with paying your deposits and potential penalties with the offset provisions if costs go greater than 25 percent? There's ways out and the penalties be waived.

So yes, the affected system process does go in its own path, but it's informing the Applicant not at Facility Study, well in advance of Facility Study Phase 1, Phase 2, and that's a business risk that they're making throughout the entire process.

Q Okay. So would you agree that there are no defined timelines for the delivery of Affected System Studies?

A Correct.

Q Okay. And I believe you testified that Duke has a, what it calls a goal of completing Affected System Studies within 60 to 90 days. And I'm sorry. That's on page 25 of your testimony.

A That's correct.

Q Okay. Sixty to 90 days from when?

A I would have to go back and reread the LGIA through the affected system process.

Q Okay. But that 60 to 90 days is just a goal, right?

A It is a goal.

Q Okay. And we have no commitments from any other utility about how long it might take them to conduct an Affected System Study, do we?

A That's correct. For example, if Juno Solar was to trigger a PJM affected system process, you're at PJM's discretion of when that Affected System

Study process would or would not be completed no different than any other potential utility.

Q Okay. So there's just -- there's really no telling when a project might receive an Affected System Study?

A Yes.

Q Okay. It could certainly be after the Facility Study was received, right?

A It could be. Yes, it could very well be. But -- so in that conversation or in that vein would be we might be able to get preliminary information and serve discovery on the affected utility to say okay, what was the nature of the upgrade. It's a substation breaker. All right. A million dollars. Okay. We can evaluate that explicit so that it would have to be more fine tuned through the Affected System Study, but if at a preliminary or a high level and we have those conversations say well, we really have about 55 miles of 230 kV that we need to upgrade and we have this other section 115 yada, yada, yada, it changes the story and the Applicant will have to evaluate those risks as they move through the process.

So if the Applicant is notified of affected system at Phase 1, they could bow out without the penalties and that would be potentially fair isn't the right word, but the other people in the queue can continue to evaluate because maybe that magnitude of that project was the tipping point that triggered the affected system and the rest of the projects may be able to come under the triggering effect.

So it's not going to necessarily implode. It's a function that continually has to be evaluated and restudied.

Q Okay. So your recommendation though is that merchant projects or that FERC-jurisdictional customers wait until they receive their Affected System Studies before they file a CPCN Application?

A That would be consistent with the EMP Applications. Because I could not make my determination of what the nature of those upgrades are nor the costs, because now becoming a potential -- so let's say hypothetically, Juno Solar triggers an affected system upgrade in DEC. So Public Staff would have to evaluate, and it's under the FERC Crediting Policy we would have to evaluate the impacts not now just to only DEP customers, we would have to evaluate the impacts now to DEC customers for energy that is going into -- again hypothetically, not trying to single out Juno, but for hypothetically where something is getting sold into PJM.

Q So it's your position that an interconnection customer should wait to receive an Affected System Study from PJM or Santee Cooper or Dominion or in a non-North Carolina utility prior to filing its CPCN Application?

A I think that would be the most ideal solution. And when one considers the termination provision of the LCOT, I don't see them any different. So if the -- under the assumption that if a merchant power plant was seeking a CPCN from the Utilities Commission and they had an unknown affected system cost but was applied to the overall LCOT, I don't see the difference of getting a $4.00, in my words, a blank check paying all the upgrades, or not paying for the upgrades, but potentially paying for the study being exposed to withdrawal penalties only up to multiple months down the road or years down the road and be notified of this open-ended affected system process.

Q So I think you mentioned the possibility of, you know, what would happen if Juno triggered affected system impacts on DEC. So, Ms. Miller testified in her rebuttal that Juno is committed not to seek reimbursement from North Carolina ratepayers for any affected system cost. Did you hear that?

A I agree with that and that's some of the fluid nature that has been discussed over time through the testimony. So part of that would make sure, I mean, the devil is in the details. If one were to make it a condition, I mean, I think the condition would have to be explicit that the LCOT does not apply towards affected system cost. Affected system cost that the Applicant is voluntarily requesting that they pay for their own upgrades and affected system.

Q So if there were condition in Juno's CPCN that provided that Juno would not seek reimbursement for any affected system costs -- upgrade costs that would be charged to North Carolina ratepayers, would that resolve the Public Staff's concerns about affected system upgrade costs?

A In terms of the recommendation that the Public Staff would need to review both the Facility Study and the affected system cost, that may be -- I would have to think on it more, but that very well may be a mitigation measure as you discussed.

Q Okay. And if Juno were to trigger affected system upgrades on PJM's system, they would not get reimbursement for those in any event, would they?

A That is my current understanding, yes.

Q Okay. Are there any other systems that Juno might trigger affected system upgrades on?

A I have the transmission map online, so I'm trying to evaluate it. It would be too much speculation to make any assumptions at this time without fully understanding the -- sort of the base case or the potential retirements or what they've referred to as defacts on what elements are turned down in the system to handle the injection of the new generation. Too much speculation at this time.

Q Okay. Thank you. But Juno would not in any

event be getting a reimbursement of affected system upgrade costs from North Carolina ratepayers; is that right? If it accepted the condition that we just discussed a minute ago.
A Under that condition with that explicit caveat, yes.
Q Okay. Thank you. So let's move on a little bit. Mr. Metz, in your testimony you discuss H.B. 951; is that right?
A Generally, yes.
Q Okay. And that law requires the Commission to take all reasonable steps to reduce emissions from Duke's generating fleet in North Carolina by 70 percent by 2030; is that right?
A In part. There's a couple of provisions that under certain technologies there is a little bit of a grace period. I don't have that law in front of me. Subject to check, I believe it was a year or two under certain provisions. And there's one other caveat, but go ahead.
Q Okay. So, Ms. Miller testifies that with regard to H.B. 951 that Duke's IRP, which the Commission has now approved, shows that achieving this goal of 70 percent reduction require procuring at

least 9 GW of solar by 2030. Does that sound right to you?

A If you can point me to her testimony, please.

Q Sure. Page -- let's see this is her -- let's see -- I'm sorry -- I think it's her direct testimony page 15. I'm sorry. That's her rebuttal testimony on page 15.

A All right. Page 15 the question starting at line 14?

Q Yeah. Line -- yeah, line 16 is the testimony.

A So yeah. Please proceed.

Q Okay. Yeah, so she says "Duke's Integrated Resource Plan pending before the Commission shows that amount of solar that must be procured to be at least 9 GW, although intervenors have put on evidence that would support a much higher number." Do you agree that she's appropriately characterizing the IRP and what others have said in the IRP docket?

A Well, I'm somewhat confused on the -- I mean, she jumps -- and not on purposely, but I couldn't discern whether she was talking about the North Carolina IRP or the South Carolina IRP. I know she talks about sort of at the last line the amount of required solar could be closer to 11 GW, so that would point to me that she was referencing South Carolina's IRP and not necessarily North Carolina's IRP.

And I remember the other caveat that I wanted to eventually discuss that 951 is that the Commission has to create, implement, and follow through on the Clean Carbon Plan or that equivalent and that would inform the steps and evaluation steps on the generation portfolio that would be into the future which I would hope that or at least the Public Staff would also be evaluating the integral Phase 2 report which would be evaluating the amount of potential generation resources to compliment the existing system while balancing the retirement of existing systems to maximize efficient utility build-out on both generation and transmission.

Q Okay. Well, would you agree that based on this 9 GW number that was included in Duke's North Carolina IRP, Duke would need to add at least a gigawatt of solar per year through 2030 and maybe more to reach the decarbonization goals of H.B. 951? Do you agree with that?

A No. I don't necessarily agree with that, because now I don't know if she's mixing Duke Energy Carolinas or Duke Energy Progress, or if she's looking at the Joint Study Case which is generally just sort of a hypothetical, because they are two independent BAs. I don't know if you can provide any more discretion on that, because Duke Energy Progress has a magnitude greater. I don't know that -- I can't recite the exact numbers of solar generation above Duke Energy Carolinas --

Q Okay. I'll represent to you that Ms. Miller is, I believe, is speaking collectively of the two utilities. Does that -- do those numbers sound right when considered in the context of both utilities?

A I'm going to have to know which portfolio, because under Portfolio A no new solar generation. I believe I filed a -- I did file a testimony on this, but no new solar generation was economically selected on Portfolio A respecting that at that point in time in the 2020 IRP we did not have H.B. 951.

Q Okay.

COMMISSIONER DUFFLEY: I need to give our court reporter a break, so how much longer do you anticipate questioning?

MR. SNOWDEN: I would say -- and I will try to trim it down, but I'd say about an hour left. I'll try to -- I will -- if we have a break, I will try to trim that down to get --

COMMISSIONER DUFFLEY: Okay. Well -- and you all also may need to talk about -- I mean, we have to leave at five, so look at other dates potentially that we can come back. So I think we've identified December 8th as a potential date, so if you -- if all the parties could discuss that date during the break.

We're going to go off the record. We'll be back on at 4:00 p.m.

(The hearing was recessed, to reconvene at 4:00 p.m.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings taken and reported by TONJA VINES in stenographic shorthand were transcribed under my direction, and that the Proceedings set forth herein and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell