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Sep 27 2022

September 27, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Correction to Transmission and Solar Procurement Panel Rebuttal Testimony
Docket No. E-100, Sub 179

Dear Ms. Dunston:

On September 9, 2022, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC's ("DEP" and together with DEC, the "Companies") filed the Rebuttal Testimony of the Transmission and Solar Procurement panel ("Transmission Panel") in the above-referenced proceeding. It has come to our attention that two corrections to the Transmission Panel's Rebuttal Testimony are necessary. Specifically, the corrections appear on page 27, lines 16-18 and page 43, lines 4-14. Redlined and clean copies of the corrected pages are included with this letter as Attachments 1 and 2, respectively.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Very truly yours,

/s/E. Brett Breitschwerdt

Enclosure

cc: Parties of Record

projects can be placed in-service on an accelerated schedule and interconnection process improvements are identified and implemented, annual solar procurements and interconnections may be able to be increased. However, the Companies will need to continue to be confident that the planned number of interconnections can be executed in the timeframe required given the aforementioned hurdles with outage coordination.

Q. WHAT IS YOUR RESPONSE TO WITNESS WATTS' ASSERTION THAT DUKE SHOULD ENCOURAGE THIRD-PARTY SELF-BUILD OF INTERCONNECTION FACILITIES AND STAND-ALONE NETWORK UPGRADES?[25]

A. Based on Duke Energy's interconnection standards,[26] a transmission connected solar facility, if connected to a networked 100 kV or 115 kV transmission line, must have line switches installed on both sides of the point of interconnection for isolation purposes if a line switch is not already installed on the line within one mile of the tap line. If certain criteria are not met for 230 kV interconnections, a multi-breaker station is recommended.~~These standards also require that a transmission solar facility, if connected to a networked 230 kV transmission line, must have a ring bus station installed at the point of interconnection for protection and~~

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[25] CPSA Watts Direct Testimony at 10-11.

[26] Susbstation Configuration Guideline for Transmission Inverter Based Interconnections, https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/GDLF-EGR-TRM-00004_Rev_1_Substation_Configuration_Guideline_for_Interconnections_OASIS_v1.pdf (last visited Sept. 9, 2022).

~~isolation purposes.~~ Duke Energy would also need to connect the interconnection infrastructure to the DEC or DEP system and modify associated relaying. These steps in the interconnection process require on average a five-week transmission line outage. Thus, connection of a solar facility to a 100 kV, 115 kV, or 230 kV line requires a coordinated transmission line outage on the DEC or DEP system, as shown by Figure 5 in the Transmission Panel Direct Testimony. Because of this impact to day-to-day transmission operations, reliance on third-party construction introduces significant reliability risk. In fact, the DEC and DEP OATT and the modifications required by FERC Order No. 845 acknowledged this distinction, providing the option for interconnection customers to build interconnection facilities and stand-alone network upgrades, not network upgrades that risk adverse reliability impacts.

Q. HOW DO YOU RESPOND TO WITNESS WATTS' CONTENTION THAT DUKE'S INTERCONNECTION STUDY CRITERIA GO BEYOND NERC REQUIREMENTS, AND THAT REVISING DUKE'S CRITERIA COULD REDUCE THE NEED FOR NEW INFRASTRUCTURE, RESULTING IN SHORTER INTERCONNECTION TIMES?[27]

A. I disagree, and I also do not believe this is the appropriate forum to be debating NERC reliability standards. The NERC reliability standards, as

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[27] CPSA Watts Direct Testimony at 16-17.

Q. IS STANDALONE STORAGE APPROPRIATE FOR AN OPEN BUILD-OWN-TRANSFER PROCUREMENT PROCESS AT THIS TIME?[38]

A. The Companies support all available avenues to keep customer costs low, and would be open to further exploring options for a future build-own-transfer RFP for standalone storage. In such a scenario, the RFP would be subject to Duke Energy-directed siting based on system needs, benefits, timing, and other requirements. The technical requirements for a standalone storage acquisition RFP would be very specific, including approved vendors and equipment, design standards, safety requirements, capacity and energy content, and appropriate use case-driven capabilities. The Companies continue to believe that a BOT model may not be appropriate or feasible in all scenarios but the Companies would, in every case, utilize competitive sourcing processes for the benefit of customers.~~No. For the reasons stated above, standalone storage is a different resource than solar paired with storage and requires a different planning approach, which does not make it appropriate for a full resource build-own-transfer solicitation at this time. The Companies must determine the needs, locations, and characteristics of the battery, not the third-party developer.~~

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[38] CCEBA DiFelice Direct Testimony at 21.

ATTACHMENT 2
CLEAN VERSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan And Carbon Plan	))))))	**REBUTTAL TESTIMONY OF DEWEY S. ROBERTS II AND MAURA FARVER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

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

A. My name is Dewey S. Roberts II ("Sammy"), and my business address is 3401 Hillsborough Street, Raleigh, North Carolina. I am the General Manager, Transmission Planning and Operations Strategy for Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC" and together with DEP, "Duke Energy" or the "Companies"). I am providing rebuttal testimony today with Maura Farver as the "Transmission and Solar Procurement Panel."

Q. ARE YOU THE SAME PANEL THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes. Witness Farver also addresses solar procurement issues in greater detail, so we have expanded the panel name to "Transmission and Solar Procurement."

Q. IS THE PANEL INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. Transmission and Solar Procurement Panel Rebuttal Exhibit 1 presents Table 4-13 from Chapter 4 – Execution Plan of the Carbon Plan filed on May 16, 2022. Transmission and Solar Procurement Panel Rebuttal Exhibit 2 presents provides Rebuttal Figure 1 as presented in our rebuttal testimony in a larger, more readable format. Transmission and Solar Procurement Panel Rebuttal Exhibit 3 presents a list of the Red Zone Expansion Plan ("RZEP") projects that indicates those projects for which the Companies are seeking Commission acknowledgement of their need for execution of the Carbon Plan.

Q. MR. ROBERTS, WHAT IS THE PURPOSE OF THE TRANSMISSION AND SOLAR PROCUREMENT PANEL'S REBUTTAL TESTIMONY?

A. The purpose of this panel's rebuttal testimony is to respond to other parties' testimony related to near-term transmission related actions the Companies have indicated are imperative to pursue for executing a Carbon Plan portfolio and making progress in the Companies' continuing system-wide Carolinas energy transition consistent with North Carolina Session Law 2021-165 ("HB 951") targets.

Table 4-13 of Chapter 4 – Execution Plan, attached as Transmission Panel Rebuttal Exhibit 1, identifies five key near-term actions that are critical to immediately beginning the transmission system transformation actions necessary for successful execution of Carbon Plan resource portfolios. These actions include (modified from the original Table 4-13 to reflect current status):

1. Obtained FERC approval of a generation replacement queue process
2. Subject to Transmission Advisory Group stakeholder review and NCTPC approval of the RZEP projects, start RZEP transmission projects included in 2022 NCTPC Local Transmission Plan
3. Start preliminary routing, scoping, siting, right-of-way acquisition for offshore wind transmission projects with point of interconnection at New Bern Substation
4. Perform further Transmission Planning evaluations/studies for transmission transformation needed to facilitate coal generation retirements

5. Request interconnection studies for needed MW levels of offshore wind being injected into New Bern Substation

This Rebuttal Testimony will further demonstrate for the Commission the critical importance of these near-term transmission related actions to enable the reliable and successful execution of the Carbon Plan. Specifically, I will respond to testimony regarding the need for proactive transmission planning, the need and next steps for the RZEP projects, and address specific topics related to the injection of offshore wind into the DEP transmission system, the Companies' generator replacement process, and transmission-related modeling assumptions.

In addition, Ms. Farver addresses certain solar procurement and storage development and procurement issues raised by the Public Staff and intervenor testimony.

I. PROACTIVE TRANSMISSION PLANNING AND RED ZONE EXPANSION PLAN ("RZEP") PROJECTS

Q. MR. ROBERTS, DID ANY PARTY DISAGREE WITH THE COMPANIES THAT HB 951 ESTABLISHES NEW PUBLIC POLICY GOALS INCLUDING DEVELOPMENT OF A CARBON PLAN?

A. No. Public Staff Witness Metz testified that the Commission should acknowledge the public policy goals for North Carolina as part of its 2022

Carbon Plan, as the Companies request.[1] No other party opposed this request.

Q. DID OTHER PARTIES IDENTIFY PROACTIVE TRANSMISSION PLANNING AS KEY TO RELIABLY EXECUTING THE CARBON PLAN?

A. Yes. There was general recognition among the parties who testified on this matter of the need for proactive transmission planning.[2]

Q. DO YOU AGREE?

A. Yes. The reactive nature of relying on commitments in generator interconnection agreements before beginning construction of transmission network upgrades to enable new generator interconnections will not support the pace or volume of interconnecting resources necessary to implement the Carbon Plan. A proactive transmission planning approach, that is scenario-based and coordinates transmission network upgrades, greenfield transmission expansion, and explores alternatives is necessary to meet the requirements of the Carbon Plan in the specified timeframes and in a cost-effective manner.

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[1] Public Staff Metz Direct Testimony at 46-47.

[2] *See, e.g.,* Public Staff Metz Direct Testimony at 36-37; CPSA T. Norris Direct Testimony at 7; NCSEA, et al. Caspary Direct Testimony at 4-5.

Q. HOW DOES DUKE ENERGY INTEND TO NAVIGATE PROACTIVE TRANSMISSION PLANNING CONSIDERING THE POSSIBLE FERC ORDERS RESULTING FROM THE TRANSMISSION PLANNING NOPR?

A. Duke Energy will continue to engage with the Transmission Planning Notice of Proposed Rulemaking ("NOPR")[3] proceeding and will implement FERC Orders on changes to transmission planning processes in its Joint Open Access Transmission Tariff ("OATT"). Duke Energy will also engage with North Carolina Transmission Planning Collaborative ("NCTPC") Oversight/Steering Committee ("OSC") members, NCEMC, and Electricities, in reviewing and improving NCTPC Local Transmission Planning processes to include the necessary proactive planning process steps for cost-effective transmission planning for the transmission systems within DEC and DEP. In addition, DEC and DEP will continue to participate in regional planning through the Southeastern Regional Transmission Planning ("SERTP") process that will adopt FERC Orders resulting from the FERC Transmission Planning NOPR. The development of local, regional, and interregional transmission plans ensures efficient and cost-effective planning to maintain or improve reliable service to DEC and DEP customers while managing the retirement of generation and addition of new planned generation.

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[3] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

Q. ARE THE RZEP PROJECTS A KEY EXAMPLE OF DUKE ENERGY'S COMMITMENT TO PROACTIVE PLANNING?

A. Yes. Duke Energy considers the RZEP projects to be a necessary and appropriate first step in this direction as these projects have multiple value propositions, including replacing aging infrastructure, resiliency improvements, lower impedance, thus lower transmission losses, in addition to facilitating improvement in the pace and volume of interconnection of incremental resources.

Q. ARE THE RZEP PROJECTS A KEY COMPONENT TO RELIABLE AND SUCCESSFUL EXECUTION OF THE CARBON PLAN?

A. Yes. The RZEP projects will allow for more interconnections of solar facilities in the "Red Zone," a high solar viability region of the DEC and DEP systems where development and interconnections of solar facilities have been thwarted due to extensive network transmission upgrades required. To date, these Red Zone upgrades have created insurmountable cost hurdles for developers of one or two projects being asked to bear the upfront burden of that cost.

Q. DO OTHER PARTIES AGREE WITH THE COMPANIES REGARDING THE NEED FOR THE RZEP PROJECTS?

A. Yes. There is widespread agreement among many parties, including the Public Staff, NCEMC, CPSA, CCEBA/MAREC, and NCSEA et al., that the near-term action of developing and constructing the RZEP projects is a critical path step to executing the Carbon Plan. For example, CPSA witness

Norris acknowledges in his testimony that "Duke has amply demonstrated that the RZEP upgrades are needed to achieve compliance with HB 951 and that ratepayers would be well served by the completion of those upgrades as soon as possible."[4] CCEBA and NCSEA also acknowledge the RZEP projects are necessary.[5] NCEMC witness Ragsdale "recognizes that the RZEP projects are largely designed to address transmission constraints in some of the most cost-effective and desirable locations for additional solar development in North Carolina and is committed to continuing to work with Duke to evaluate these projects through the NCTPC process." NCEMC witness Ragsdale also emphasizes that "Duke's expedited timeline for RZEP should not result in the RZEP projects being prioritized over other transmission projects needed for reliability and maintaining service quality for retail and wholesale customers."[6] Duke Energy agrees with NCEMC witness Ragsdale on this point and will continue to engage with affected systems in the context of generator interconnections as contemplated in the OATT.

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[4] CPSA Norris Direct Testimony at 7.

[5] CCEBA/MAREC Gonatas Direct Testimony at 18-20; NCSEA et al. Caspary Direct Testimony at 13-14.

[6] NCEMC Ragsdale Direct Testimony at 5.

Q. WHAT ARE THE PUBLIC STAFF'S SPECIFIC RECOMMENDATIONS WITH RESPECT TO THE RED ZONE PROJECTS AND SUPPLEMENTAL STUDIES?

A. The Public Staff is generally supportive of the supplemental studies and supports Commission acknowledgment of the majority of the RZEP projects. Witness Metz states that the three DEP projects identified by this Panel in its direct testimony that did not demonstrate strong solar dependence (project #s 9, 11, and 12)[7] should be delayed at this time.[8]

In addition, witness Metz recommends the Companies delay an additional three RZEP projects. For DEC, he does not recommend DEC proactively build RZEP project #4 (Clinton 100 kV, Bush River-Laurens) at this time, "based on the relatively few generator facilities impacting that line and the unclear causal relationship between future solar generation and this upgrade."[9] At the same time, witness Metz recognizes that "this potential line upgrade will likely be needed in the near future if solar generation continues to attempt to interconnect in this area given its proximity to other transmission projects in question."[10]

For DEP, witness Metz recommends DEP RZEP projects #7 and 14 (the Erwin-Fayetteville 115 kV line and the Camden-Camden Dupont 115 kV line) be removed from the Red Zone Expansion Plan at this time, noting

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[7] The numbers associated with the RZEP projects correspond to the order of projects listed at Table P-3 of Appendix P.
[8] *Id.* at 44.
[9] *Id.* at 42.
[10] *Id.* at 42.

that these projects "have approximately 25% of all common upgrades affecting the proposed transmission projects in the study," and that project #14 "appears relatively small in scope compared to the other transmission upgrades."[11] Similar to his DEC recommendation, witness Metz asks the Companies to discuss the impact of delaying these projects on reliability and cost effectiveness and provide any additional support for the need for these projects.

Q. ARE THESE THREE LINES LOCATED WITHIN THE HIGH SOLAR VIABILITY RED ZONE AREAS?

A. Yes. Rebuttal Figure 1 below presents a map that shows the overlapping proximity of the projects that the Public Staff recommends not building at this time—DEC project #4 and DEP projects #7 and #14—with the high solar viability areas in DEC and DEP.

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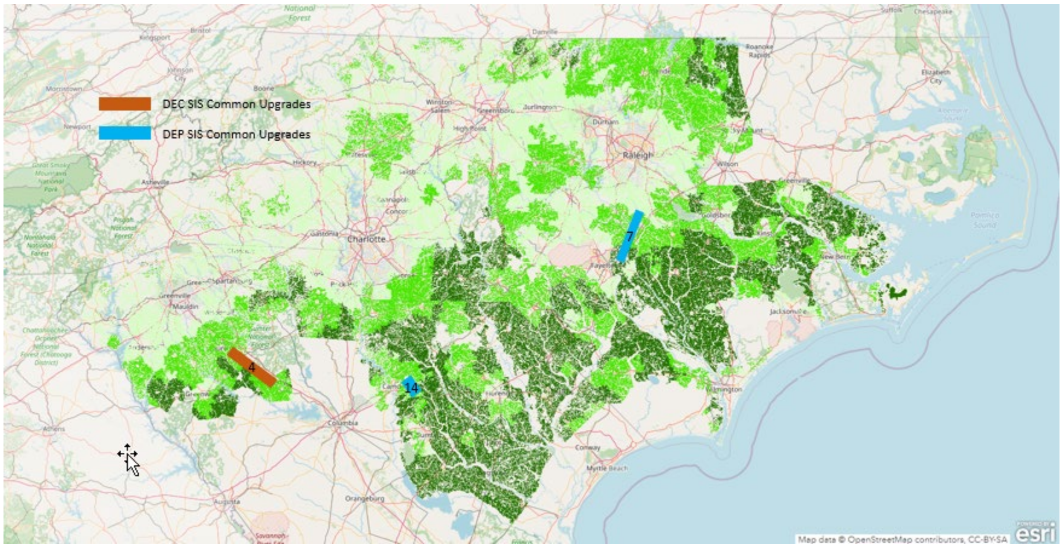
[11] *Id.* at 44.

Rebuttal Figure 1 – RZEP Projects #4, #7, and #14 Overlaid with High Solar Viability Areas[12]



Q. DO YOU AGREE WITH THE PUBLIC STAFF'S RECOMMENDATION THAT AN ADDITIONAL THREE RZEP PROJECTS NOT BE PURSUED AT THIS TIME?

A. I do not agree with the Public Staff recommendations with respect to two of these projects. The results from prior generator interconnection studies and the supplemental studies demonstrate that the Clinton 100 kV B/W lines and Erwin – Fayetteville 115 kV line will be necessary to integrate hundreds of MW of generation in the red zone area and provide a clear causal relationship between the incremental addition of generation in this high solar viability region and the need for these network upgrades.

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[12] Rebuttal Figure 1 is also replicated in Transmission and Solar Procurement Panel Rebuttal Exhibit 2.

Specifically, the RZEP mapping of prior generator interconnection studies (Exhibit 1 of the Transmission Panel Direct Testimony) reflects the Clinton 100 kV Black/White lines in DEC's red zone have over 428 MW of solar facilities mapped to needing this network upgrade and the DEC supplemental study (Exhibit 3 of the Transmission Panel Direct Testimony) reflects the Clinton 100 kV B/W lines had the DFax threshold and/or the line Loading Impact[13] threshold exceeded for approximately 740 MW of solar facilities considered in the study.

The DEP RZEP mapping of prior generator interconnection studies (Exhibit 2 of the Transmission Panel Direct Testimony) reflects the Erwin – Fayetteville 115 kV line in DEP's red zone has over 734 MW of solar facilities mapped to needing this network upgrade in the Transitional Cluster Study alone. The DEP supplemental study (Exhibit 4 of the Transmission Panel Direct Testimony) reflects the Erwin – Fayetteville 115 kV line had the DFax threshold and/or the line Loading Impact threshold exceeded for approximately 625 MW of solar facilities considered in the study.

While Duke Energy agrees that Project #14—the Camden–Camden Dupont 115 kV line upgrade—may be able to be postponed at this time,

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[13] **MW Output** = Real power output of the generator
Distribution Factor (DFax): The proportion of a generator's MW Output that flows on a transmission facility under the worst contingency – DFax threshold = 3%
MW Impact = MW Output x DFax
Loading Impact = MW Impact / Facility Rating – Loading Impact threshold = 1%.

Duke Energy will pay close attention to this upgrade being needed in the near-term if identified in the 2022 DISIS Phase 1 Study.

Q. WITNESS METZ ASKED THE COMPANIES TO IDENTIFY ANY CONSTRUCTION EFFICIENCIES OR COST SAVINGS ASSOCIATED WITH PROACTIVELY CONSTRUCTING ANY OF THE PROPOSED RZEP PROJECTS THAT ARE NOT SUPPORTED BY PUBLIC STAFF'S INITIAL REVIEW. PLEASE RESPOND.

A. As noted in the DEC Transitional Cluster Study report,[14] the upgrade of sections of the Clinton 100 kV B/W lines is estimated to take 48 months. If smaller generators are able to interconnect with sections of the Clinton 100 kV B/W lines prior to constructing the RZEP upgrades, additional cost could be incurred through the need for temporary line construction not contemplated in the current project scope. The DEP Transitional Cluster Study Report reflects that it would take 54 months to upgrade the Erwin – Fayetteville 115 kV line.[15] Even though DEP plans to accelerate this schedule, if delayed and outages need to be scheduled beyond 2026 that would be competing for the same outage window needed for implementing the upgrade to the Erwin-Fayetteville 115 kV line, this delay in the upgrade schedule could delay interconnecting generators dependent on this RZEP

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[14] Duke Energy Carolinas, LLC Transitional Cluster Study Phase 1 Report at 20 (Feb. 28, 2022), *available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf.

[15] Duke Energy Progress, LLC Transitional Cluster Study Phase 1 Report at 14 (Feb. 28, 2022) https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022-02-28_DEP_TC_Phase_1_Study_Report.pdf.

upgrade. Thus, the Clinton 100 kV B/W lines and the Erwin – Fayetteville 115 kV line should remain in the list of RZEP projects for which the Companies are requesting Commission acknowledgement that they are necessary for executing Carbon Plan portfolios at this time.

Q. WITNESS METZ ALSO ASKED THAT THE COMPANIES CONFIRM HIS UNDERSTANDING OF NEXT STEPS IN THE NCTPC PROCESS FOR DETERMINING PROACTIVE UPGRADES AND INCLUDING THE RZEP IN THE NCTPC LOCAL TRANSMISSION PLAN.[16] PLEASE RESPOND.

A. As stated in this Panel's direct testimony, the next steps in the NCTPC process for incorporating the RZEP projects are to: 1) present the updated status of the RZEP projects to the Transmission Advisory Group ("TAG") stakeholders and receive feedback/input on the projects, and 2) seek approval from the NCTPC to include the RZEP projects in the 2022 Local Transmission Plan, all in accordance with the FERC-approved Local Transmission Planning Process as described in Attachment N-1 of the OATT. The Commission's acknowledgement that the proposed RZEP projects are needed to interconnect new solar generating facilities and necessary for execution of the Carbon Plan would bolster the position that the RZEP projects need to be included in the 2022 NCTPC Local Transmission Plan.

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[16] Public Staff Metz Direct Testimony at 46-47.

Q. WHY SHOULD THE COMMISSION ACKNOWLEDGE THE RZEP PROJECTS AS NECESSARY FOR EXECUTION OF THE CARBON PLAN?

A. In its June 10, 2022, 2022 Solar Procurement Order, the Commission directed Duke Energy not to include RZEP projects in the 2022 DISIS baseline, concluding that doing so would be premature based on its finding that "no party has presented competent evidence that the RZEP projects are necessary to achieve the Carbon Plan."[17] The Commission encouraged Duke Energy and any intervenor supporting the RZEP "to provide substantial evidence supporting the necessity of the RZEP projects to achieve the goals of the Carbon Plan in that proceeding."[18] In response to the Commission's order, the Companies conducted supplemental studies to provide substantial evidence of the necessity of the RZEP projects to achieve the goals of the Carbon Plan. The results of these supplemental studies are included in this Panel's direct testimony. Given the Commission's directives in the 2022 Solar Procurement Order, the Companies are therefore seeking Commission acknowledgement that there is substantial evidence demonstrating the need for the RZEP projects for implementation of Carbon Plan portfolios.

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[17] *In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c)*, Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments at 7, Docket Nos. E-2, Sub 1297, E-7, Sub 1268 (Jun. 10, 2022) ("2022 Solar Procurement Order").

[18] *Id.*

Q. MR. ROBERTS, IS THERE AN UPDATED LIST OF RZEP PROJECTS THAT DUKE ENERGY REQUESTS THE COMMISSION ACKNOWLEDGE AS NEEDED IN THIS INITIAL CARBON PLAN?

A. Yes. Transmission and Solar Procurement Panel Rebuttal Exhibit 3 presents the list of RZEP projects that Duke Energy requests the Commission acknowledge in approving this initial Carbon Plan.

Q. WHAT ARE DUKE ENERGY'S NEXT STEPS IF THE COMMISSION DOES NOT ACKNOWLEDGE THAT THE RZEP PROJECTS PRESENTED IN REBUTTAL EXHIBIT 3 ARE NECESSARY FOR EXECUTION OF THE CARBON PLAN?

A. Duke Energy continues to believe that all of the originally identified RZEP projects are necessary to interconnect the volumes of solar needed to meet HB 951 targets and progress the system-wide Carolinas energy transition. As shown in the Transmission Panel direct testimony, the supplemental studies provide evidence of the need for 15 of the original 18 RZEP projects for initial procurements of solar to be interconnected by 2030. However, past transmission planning studies have shown these three upgrades to be needed for interconnecting solar projects, and the Companies continue to view them as needed.

The Public Staff recommends that DEC and DEP not move forward at this time with constructing three of the 15 projects supported by the supplemental studies. The Companies respectfully disagree with this recommendation for two of those three projects (the Clinton 100kV B/W lines and the Erwin – Fayetteville 115kV line). The Companies acknowledge that Project #14, the Camden-Camden Dupont 115 kV line upgrade, may be able to be postponed at this time, but nevertheless continue to believe that this project will be necessary for timely execution of the Carbon Plan.

As I discussed above, the request for the Commission to acknowledge the need for the RZEP is driven by the Commission's directives in the 2022 Solar Procurement Order and the Companies' desire to confirm that it has satisfied that directive. However, regardless of the outcome of the Commission's acknowledgement of the RZEP projects being necessary, the Companies will continue to iteratively evaluate through the NCTPC the need for and benefits of proactive transmission planning projects to interconnect new generation, enable coal unit retirements as part of the system-wide Carolinas energy transition and to implement the public policy requirements of HB 951. In doing so, the Companies will continue to follow the procedures in its OATT for approval of transmission projects for inclusion in its Local Transmission Plan.

II. TRANSMISSION PLANNING FOR OFFSHORE WIND

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION THAT THE COMMISSION DENY DUKE'S REQUEST TO BEGIN NEAR-TERM RESOURCE DEVELOPMENT ACTIVITIES FOR OFFSHORE WIND?

A. Whether, how much, and when offshore wind generation is needed to achieve the Carbon Plan is beyond the scope of my responsibilities. However, for the avoidance of doubt, the Companies need to immediately start preliminary routing, scoping, siting, and right-of-way acquisition for offshore wind transmission projects with the point of interconnection at the New Bern Substation in order to meet an in-service date that facilitates bringing offshore wind energy into the DEP system by 2030. Delaying these activities to 2024 or beyond means the transmission infrastructure will have a later in-service date and thus, the ability to bring offshore wind energy into the DEP system will be delayed beyond 2030. Furthermore, constructing the transmission needed to interconnect offshore wind has substantial execution risk and 2030 is already expected to be very challenging to achieve.

Q. HOW DO YOU RESPOND TO AVANGRID'S ASSERTION THAT COST EFFECTIVE INJECTIONS OF OFFSHORE WIND OF 1.3 GW ARE POSSIBLE AT EITHER THE HAVELOCK OR NEW BERN POINTS OF INTERCONNECTION WITHOUT 500 KV UPGRADES?

A. Avangrid witnesses Starrett and Gallagher claim that 1.3 GW of offshore wind can be delivered even without the 500 kV grid expansion considered in the Carbon Plan. First, they state Duke Energy's proposal to interconnect at New Bern burdens the first offshore wind projects with this nearly $1 billion cost of this expansion, implying it is a requirement for success. This assertion is not correct. Based upon preliminary transmission planning screening analysis and as addressed in Appendix P (Transmission Planning and Grid Transformation), Duke Energy assumes in the Carbon Plan that an 800 MW offshore wind resource does not include any 500 kV expansion.[19] However, at 1,600 MW and above, Duke Energy's modeling assumes a 500 kV expansion is needed to reliably transfer offshore wind energy into the DEP system.

Further, as stated in this Panel's direct testimony, New Bern is expected to be a superior and less costly injection point than Havelock. The Havelock 230 substation has only three 230 kV lines connected, one of

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[19] Carbon Plan Appendix P at 18 ("The screening studies performed to date as part of the 2020 NCTPC study have indicated that 800 MW of offshore wind can be injected at New Bern 230 kV without the addition of major new network transmission lines but with some significant upgrades to the existing system in the New Bern area.").

which goes east to the peninsula-type area of Morehead City. Extensive 230 kV upgrades would likely be needed to accommodate 1.3 GW of energy injection considering the approximate 2,600 MW of generation just to the south at DEP's Brunswick Nuclear Station and Sutton Plant and the nearby solar facilities. In contrast, the New Bern 230 kV substation has five 230 kV lines connected and injecting 1.3 GW of offshore wind energy into the New Bern 230 kV substation could well be possible without any 500 kV expansion. That amount of power injection into New Bern would still likely not be as simple as Avangrid seems to suggest. Several factors would influence the actual network upgrades needed, including considering the nearby generation from Brunswick Nuclear Station, Sutton Plant, Lee Energy Complex, and solar facilities at full output to ensure retention of firm deliverability of that generation during a summer peak study.

Also, as noted in the 2020 NCTPC Offshore Wind Study Report, "No other generation from the DEC, DEP, or PJM generator interconnection queues was added. These generator interconnection queues contain thousands of MW of possible generation that may or may not actually interconnect and which could significantly affect the flows on the DEC, DEP, and Dominion transmission systems in unknown ways. The results of this study could change significantly depending on which and how much generation in those queues moves forward to interconnection."[20] As shown at Figure 2: 2022 DISIS Red-Zone Map from the Transmission Panel Direct Testimony, there are several solar facilities requesting interconnection in the counties in close proximity to the Havelock and New Bern area that could easily influence the network transmission upgrade needs for injecting offshore wind into the Havelock/New Bern area.

Q. HAS AVANGRID SUBMITTED A GENERATOR INTERCONECTION REQUEST TO DEP?

A. No. While Avangrid is taking steps to perform due diligence, including assessing the potential transmission costs to interconnect its proposed project, the only way to definitively know what transmission network upgrades would be required for a given amount of offshore wind, whether 800 MW, 1,300 MW, 1,600 MW, or 2,400 MW injected into the Havelock/New Bern area is through a formal generator interconnection request and subsequent Phase 1 and Phase 2 generator interconnection cluster studies.

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[20] Report on the NCTPC 2020 Offshore Wind Study at 1 (Jun. 7, 2021), *available at* http://www.nctpc.org/nctpc/document/REF/2021-06-07/W_Doc/2020_NCTPC_Offshore_Wind_Report_06_07_2021-FINAL%20Rev%202.pdf.

III. GENERATOR REPLACEMENT

Q. PLEASE UPDATE THE COMMISSION ON THE STATUS OF THE COMPANIES' GENERATOR REPLACEMENT REQUEST TO FERC.

A. FERC approved the Companies' generator replacement proposal on September 6, 2022.[21] FERC approval of the generator replacement interconnection study process is a key initial accomplishment in the Companies' execution plan.

Q. GIVEN FERC'S APPROVAL OF THE COMPANIES' GENERATOR REPLACEMENT PROCESS, WHAT ARE THE COMPANIES' NEXT STEPS?

A. The Companies have already contracted with a Generation Replacement Coordinator ("GRC") as an independent entity to conduct generation replacement request studies. These contracts were submitted as part of the DEC and DEP Generator Replacement filing and were included in the FERC Order accepting the Tariff Provisions. The FERC-approved process is part of the OATT posted on the DEC and DEP OASIS sites. The administrative processes for receiving requests, the GRC access to retrieving study base cases, and communications protocols with generation replacement customers are being established and should be in place by

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[21] *Duke Energy Carolinas, LLC, et al.*, 180 FERC ¶ 61,156 (2022).

October 2022 to facilitate the start of receiving and processing generation replacement requests.

Q. WHY DO THE COMPANIES VIEW A FERC-APPROVED GENERATION REPLACEMENT PROCESS AS A KEY NEAR-TERM ACTION?

A. As stated in the Transmission Panel direct testimony, a generator replacement process will be critical to efficient, timely, and cost-effective replacement of existing coal-fired generation with new generation that interconnects at the same switchyard where the retiring generation is located. Utilization of the same switchyard for interconnection will save the cost of potentially expensive interconnection facilities and potential network upgrades that would be required if the same replacement generation was constructed at a greenfield site.

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS METZ'S TESTIMONY ON THIS TOPIC?

A. The Companies agree with the Public Staff's perspective on this issue.[22] The generation replacement process should not be used blindly just because it can keep transmission network upgrade costs low; any generation replacement resource needs to be evaluated holistically considering location, resource capital and production costs, associated transmission costs, and reliability considerations. Based on past IRP comments and input

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[22] Public Staff Metz Direct Testimony at 48-49.

from the Commission, this is the manner in which the Companies are evaluating resources for capacity expansion planning for selecting resources for the Carbon Plan. That said, the Companies do view the generation replacement process as providing a valuable tool for evaluating potential generation replacement options to facilitate coal generation retirements and achieving the most cost-effective and reliable option for customers.

IV. TRANSMISSION RELATED MODELING ISSUES

Q. DO YOU HAVE ANY RESPONSES TO TRANSMISSION RELATED MODELING ISSUES RAISED BY INTERVENORS?

A. Yes. CPSA raised a number of arguments regarding modeling issues to which transmission is closely related. In this section of our rebuttal, I will provide a transmission perspective on these issues, to further support the rebuttal testimony of the Modeling and Near-Term Actions Panel.

A. Solar Interconnection Constraint

Q. HOW DO YOU RESPOND TO THE TESTIMONY OF CPSA'S WITNESSES REGARDING THE COMPANIES' SOLAR INTERCONNECTION MODELING ASSUMPTIONS?

A. CPSA's witnesses Norris and Watts contend that the Companies' planning assumptions forecasting future solar interconnections in the Carbon Plan modeling impose unreasonable constraints on solar. As the Modeling and Near-Term Actions Panel demonstrates, those contentions are not informed by the specific considerations of the DEC and DEP systems and interconnection procedures. My testimony provides additional detail and support for these constraints from a transmission perspective.

Q. CPSA WITNESS WATTS CLAIMS THAT THE COMPANIES' MODELING ASSUMPTIONS WITH RESPECT TO SOLAR INTERCONNECTIONS ARE CONSERVATIVE, AND THAT INTERCONNECTING 20 TO 21 NEW SOLAR GENERATING FACILITIES TO THE COMPANIES' TRANSMISSION SYSTEMS, YIELDING 1,800 MW/YEAR, "SHOULD BE COMFORTABLY ACHIEVABLE."[23] DO YOU AGREE WITH HIS ASSESSMENTS?

A. No. Witness Watts bases his statement on the observation that Duke Energy interconnected approximately 750 MW of new solar in 2015 and 2017. Ninety percent or greater of those projects were distribution level connections, which are significantly less complex because they do not require transmission outages to connect, and the interconnection facilities are significantly smaller than transmission interconnection facilities. The time to connect from signing the interconnection agreement to commercial operation was less than a year for a distribution level project versus 26-32 months currently for transmission level projects. Furthermore, the ability to interconnect solar facilities to the Companies' systems without extensive transmission network upgrades (*i.e.*, the "low hanging fruit") has occurred with the 4+ GW of solar already interconnected. Public Staff witness Metz

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[23] CPSA Watts Direct Testimony at 14.

recognizes this diminishing ability to interconnect additional resources to the Companies' systems without additional transmission system expansion.[24] As shown in Figure 15 in the Modeling Panel Direct Testimony, the Companies believe that 14 to 15 interconnections can likely be achieved in the near-term. From a transmission perspective, this is a reasonable but aggressive target. However, based upon my detailed knowledge of the Companies' transmission system and extensive familiarity with the Red Zone constraints, it is my opinion that it would be very difficult, and possibly unachievable, to make 20 to 21 interconnections in a year from an outage and other transmission constraints viewpoint.

As past manager of the DEP transmission outage coordination group, one of the biggest constraints for the pace of solar interconnections looking to the future is that transmission line outages are needed to construct the interconnection facilities and transmission network upgrades needed to interconnect resources. First, the interconnection facilities alone, such as installing isolation line switches and transfer trip relay protection, require a five-week outage that could be longer if the transmission line needs to be raised to accommodate the isolation line switches or if the resource is connecting to a 230 kV line that requires a new ring bus. Second, the outages for constructing network upgrades and interconnection facilities must be coordinated such that customer and system reliability is not

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[24] Public Staff Metz Direct Testimony at 38.

jeopardized during the outages. Third, additional transmission outages that must be coordinated and planned include outages for NERC relay preventive maintenance procedures, asset management outages to replace aging infrastructure, transmission maintenance outages, outages to construct and connect new retail and wholesale points of delivery, and all of these outages must be coordinated and planned such that reliability is maintained considering a contingency/forced outage of a transmission or generation asset. Fourth, due to the Carolinas peak demand summer and winter seasons, most outages are limited to occurring in the spring and fall. Fifth, the weather needs to cooperate. Hurricanes, tornadoes, high winds, heavy rains, and associated restoration activities can thwart outage work schedules, which leads to new outage coordination efforts and rescheduling and re-prioritization of work that can delay in-service dates. Finally, supply chain considerations can still upset the best laid plans, though Duke Energy will leverage the forward-looking benefits of proactive transmission planning to secure supplies needed for construction in a timely manner.

Q. WILL PROACTIVELY CONSTRUCTING THE RZEP PROJECTS HELP INTERCONNECT MORE SOLAR GENERATION?

A. Yes. Installing the RZEP projects is key to meeting interconnection targets and longer term will relieve constraints and enable new solar interconnections. As shown in the Modeling and Near-Term Action Panel's Testimony, the number of annual transmission interconnections must be executable and will improve as RZEP projects are completed. If the RZEP projects can be placed in-service on an accelerated schedule and interconnection process improvements are identified and implemented, annual solar procurements and interconnections may be able to be increased. However, the Companies will need to continue to be confident that the planned number of interconnections can be executed in the timeframe required given the aforementioned hurdles with outage coordination.

Q. WHAT IS YOUR RESPONSE TO WITNESS WATTS' ASSERTION THAT DUKE SHOULD ENCOURAGE THIRD-PARTY SELF-BUILD OF INTERCONNECTION FACILITIES AND STAND-ALONE NETWORK UPGRADES?[25]

A. Based on Duke Energy's interconnection standards,[26] a transmission connected solar facility, if connected to a networked 100 kV or 115 kV transmission line, must have line switches installed on both sides of the point of interconnection for isolation purposes if a line switch is not already installed on the line within one mile of the tap line. If certain criteria are not met for 230 kV interconnections, a multi-breaker station is recommended. Duke Energy would also need to connect the interconnection infrastructure to the DEC or DEP system and modify associated relaying. These steps in the interconnection process require on average a five-week transmission

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[25] CPSA Watts Direct Testimony at 10-11.

[26] Susbstation Configuration Guideline for Transmission Inverter Based Interconnections, https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/GDLF-EGR-TRM-00004_Rev_1_ Substation_Configuration_Guideline_for_Interconnections_OASIS_v1.pdf (last visited Sept. 9, 2022).

line outage. Thus, connection of a solar facility to a 100 kV, 115 kV, or 230 kV line requires a coordinated transmission line outage on the DEC or DEP system, as shown by Figure 5 in the Transmission Panel Direct Testimony. Because of this impact to day-to-day transmission operations, reliance on third-party construction introduces significant reliability risk. In fact, the DEC and DEP OATT and the modifications required by FERC Order No. 845 acknowledged this distinction, providing the option for interconnection customers to build interconnection facilities and stand-alone network upgrades, not network upgrades that risk adverse reliability impacts.

Q. HOW DO YOU RESPOND TO WITNESS WATTS' CONTENTION THAT DUKE'S INTERCONNECTION STUDY CRITERIA GO BEYOND NERC REQUIREMENTS, AND THAT REVISING DUKE'S CRITERIA COULD REDUCE THE NEED FOR NEW INFRASTRUCTURE, RESULTING IN SHORTER INTERCONNECTION TIMES?[27]

A. I disagree, and I also do not believe this is the appropriate forum to be debating NERC reliability standards. The NERC reliability standards, as stated on the NERC website, define the reliability requirements for planning and operating the North American bulk power system, and are developed

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[27] CPSA Watts Direct Testimony at 16-17.

using a results-based approach that focuses on performance, risk management, and entity capabilities. TPL-001-4 establishes Transmission system planning performance requirements to ensure a Bulk Electric System that operates reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. Within this standard, the P3 (Multiple Contingency) category is triggered by the "loss of generator unit followed by System adjustments." "System adjustments" is not a defined term in the NERC Glossary of Terms, and nowhere does the TPL-001-4 Standard state that a System adjustments period is intended to represent a short-term operating condition until the initial generator unit can be restored with reliability as the primary focus.

For reliable transmission planning, Duke Energy does not limit the initial generator outage duration in hopes that the contingent generator represents a "short-term operating condition." It is thus prudent to plan for the System adjustment to redispatch generation economically to prepare for the next contingency, ensure reliability, and lower production costs. In addition, this planning practice is prudent because it resets the system for the system operator to develop a reliable operating plan per NERC Reliability Standards TOP-001 and TOP-002 that can be implemented in a timely manner to respond to the next contingency.

Q. HOW DO YOU RESPOND TO CPSA'S CLAIM OF A LACK OF STAKEHOLDER OUTREACH WITH RESPECT TO THE INTERCONNECTION PROCESS IMPROVEMENT INITIATIVE THAT DUKE ENERGY MENTIONS IN ITS TRAANSMISSION PANEL DIRECT TESTIMONY?[28]

A. Duke Energy has interconnected an extraordinary amount of solar within the DEC and DEP systems and continues to work to create efficiencies and pathways for interconnecting increasing amounts of solar for execution of the Carbon Plan. Duke Energy presented this process improvement initiative at the Duke Energy Carolinas Carbon Plan Technical Subgroup Meeting Virtual Meeting on February 18, 2022. Through continued interconnection process efficiency refinements as well as implementation of RZEP projects, the pace of solar interconnections should see an improving trend through 2030 and beyond. This is a key area of focus for Duke Energy as we recognize—and are planning for—achieving an increasing pace of solar interconnections to the Companies' transmission system over the next decade to execute the Carbon Plan while ensuring reliability is maintained for our customers.

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[28] CPSA Watts Direct Testimony at 15-16.

B. Transmission Cost Adders

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSED TRANSMISSION COST ADDERS AS UTILIZED IN THE CARBON PLAN MODELING?

A. Yes. Public Staff witness Thomas states that the adders are reasonable for planning purposes.[29]

Q. DID ANY OTHER PARTY OPPOSE THE PROPOSED TRANSMISSION COST ADDERS?

A. No. No other party directly addressed the Companies' proposed adders.

C. Imports/Transfer Limits

Q. WHAT IS YOUR RESPONSE TO TECH CUSTOMERS WITNESS BORGATTI'S CLAIM THAT THE COMPANIES DO NOT CONSIDER RENEWABLE IMPORTS FROM NEIGHBORING INTERFACES ASIDE FROM PJM?[30]

A. As stated in the Transmission Panel Direct Testimony, Duke Energy is not shutting the door on the potential for acquiring Midwest onshore wind based on the results of our internal study of imports from PJM. Duke Energy has submitted a 1,000 MW firm transmission service request ("TSR") to the PJM queue and is awaiting results. The results of this TSR study will be considered in future iterations of the Carbon Plan. For the avoidance of doubt, Duke Energy would plan to acquire any such off-system onshore

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[29] Public Staff Thomas Direct Testimony at 55-56.
[30] Tech Customers Borgatti Direct Testimony at 25-26.

wind energy facility selected by the Commission, consistent with the Ownership Requirements under HB 951 as well as the manner in which the Carbon Plan models this asset for DEC.

Also, with respect to purchasing energy over other interfaces with DEC and DEP, through the Southeast Energy Exchange Market, the Companies can use as-available non-firm transmission service to purchase economic energy from neighboring entities to the south and to the west of the DEC and DEP systems.

Q. HOW DO YOU RESPOND TO CCEBA/MAREC WITNESS GONATAS' ASSERTIONS REGARDING THE COMPANIES' TRANSFER LIMITATIONS?[31]

A. DEC and DEP transfer significant amounts of energy between the two systems daily. DEP purchases 1,600 MW of capacity from independent power producers that use the DEC/DEP interface, thus the reason that firm import capability from DEC to DEP is currently limited. Wholesale customers utilize the DEC/DEP interface to transfer power from one system to the other for serving wholesale load. However, the biggest utilization of the DEC/DEP interface is through the Joint Dispatch Agreement. This Joint Dispatch dynamic schedule transferred over 6.1 million MWh, and 3.8 million MWh of economic energy between the two systems in 2021 and 2022 (through June) respectively. Also, the maximum hourly transfer of

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[31] CCEBA/MAREC Gonatas Direct Testimony at 7-12.

economic energy between the two systems was over 3,000 MWh and 2,900 MWh for the same time periods, indicating the DEC/DEP interface is healthy and utilized. Furthermore, as discussed in the Carbon Plan and further addressed in the direct testimony of Nelson Peeler and Laura Bateman on the Carolinas Utilities Operations Panel, this interface is planned to be absorbed into a single transmission zone in the future through consolidated system operations or a merger. Transmission planning for this single transmission zone will ensure reliable and economic transfers of energy are planned for across the zone.

Q. WITH RESPECT TO REGIONAL AND INTERREGIONAL STUDIES IN WHICH DEC AND DEP PARTICIPATE, CAN YOU INDICATE FOR CCEBA/MAREC WITNESS GONATAS WHICH GROUPS CONDUCT THOSE TYPES OF STUDIES?

A. Yes. As provided in Attachment N-1 of the Companies' OATT in compliance with FERC Order Nos. 890 and 1000, and as described extensively in Appendix P of the Carbon Plan, DEC and DEP participate in the NCTPC for Local Transmission Planning of the local transmission systems including the DEC and DEP transmission systems in North Carolina and South Carolina. DEC and DEP Transmission Planning also participate in Regional and Inter-regional Transmission Planning studies through SERTP.

As discussed in Appendix P, in addition to the local, regional, and inter-regional processes outlined in the OATT and required by FERC, the

Companies also participate in a number of other regional working groups, including the Carolinas Transmission Coordination Arrangement, SERC Intra-Regional Long-Term Power Flow Working Group, SERC Near-Term Power Flow Working Group, Eastern Interconnection Planning Collaborative, and the Eastern Interconnection Reliability Assessment Group.

V. SOLAR PROCUREMENT AND STORAGE DEVELOPMENT AND PROCUREMENT ISSUES

A. Solar Paired With Storage

Q. MS. FARVER, PLEASE COMMENT GENERALLY ON THE COMPANIES' EXPERIENCE WITH ADMINISTERING SOLAR PROCUREMENTS.

A. Through CPRE and now the 2022 Solar Procurement under HB 951, the Companies have gained extensive experience working with market participants and the Public Staff under the Commission's oversight to develop structured solar procurements that have delivered benefits to customers. Based on that work, there is now a strong foundation of established practices and structure (*e.g.*, evaluation practices, bid documents, contract forms) on which to build in the future. In my current role, I was responsible for designing and implementing the 2022 Solar Procurement and routinely engage with market participants to hear their perspectives on how to continue to evolve the Companies' solar procurement processes. Looking forward, the Companies are proposing substantial near-term procurements of solar and solar paired with storage in procurement events starting in 2023.

Q. CCEBA AND THE PUBLIC STAFF OFFERED TESTIMONY WITH REGARD TO THE COMPANIES' FUTURE SOLAR AND SOLAR PAIRED WITH STORAGE PROCUREMENT.[32] PLEASE SUMMARIZE THE COMPANIES' PLANS FOR FUTURE PROCUREMENT OF SOLAR PAIRED WITH STORAGE.

A. Building on the strong foundation discussed above and consistent with the Companies' recommended near-term procurements, the Companies plan to solicit both solar and solar paired with storage resources in future procurements starting in 2023 (in addition to the 2022 Solar Procurement that is already in flight).

Q. WHAT IS THE MOST SUBSTANTIAL HURDLE FACED AS THE COMPANIES LOOK TOWARDS THE COMMENCEMENT OF THE PROCUREMENT OF SOLAR PAIRED WITH STORAGE?

A. The most substantial hurdle will be the development of new contractual structures for solar paired with storage. While the PPAs for solar-only projects are well developed based on prior procurements, it will be necessary to develop substantially new contract forms to facilitate the purchase of output from third-party owned solar facilities that are paired with storage that meets the HB 951 requirement to be dispatched, operated,

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[32] CCEBA DiFelice Direct Testimony at 20-24; Public Staff Thomas Direct Testimony at 52-53.

and controlled "in the same manner as the utility's own generating resources."

Q. PLEASE COMMENT ON THE CRITICAL IMPORTANCE OF THOSE CONTRACTS.

A. In the case of utility-owned resources, the Companies will have complete operating control of the facilities and will be able to operate them as needed over the life of the asset to maximize the benefits to customers. The Companies will therefore have unlimited discretion to adjust operation over time as technology and system conditions evolve in ways that are foreseeable and in other ways that are not foreseeable.

However, in the case of third-party owned facilities, the Companies' ability to operate such facilities will be controlled by the terms of the contract, which may have a contract term of 20 or 25 years. Given the fact that the operation of substantial amounts of solar paired with storage is new to the Duke Energy system and the fact that such resources will be in operation for such a long time horizon, it is crucial to ensure that the contract governing these assets provides the appropriate structure that will allow the Companies to maximize the value of the assets not just in the short-term but also in the future as system conditions change and technology evolves. There is significant complexity in establishing fair compensation structures for project owners that also properly incentivize production and require high performance of the resources. The contract terms and pricing should be designed to enable the Companies to maximize the benefits from the solar plus storage over the full contract term at a price that is fair to customers and protects them from overpayment. In addition, the contracts must provide adequate risk adjusted revenue to the project owner to enable them to attract capital to finance the projects. Reaching an appropriate balance between these objectives will require collaboration and compromise.

Q. WHAT ARE THE COMPANIES' PLANNED NEXT STEPS IN THIS RESPECT?

A. The Companies plan to engage stakeholders with respect to such contract development in advance of the 2023 procurement. We are currently targeted to start that engagement in the fourth quarter of this year.

Q. DO YOU AGREE WITH CCEBA WITNESS DiFELICE THAT THE COMMISSION SHOULD DIRECT ALL FUTURE SOLAR PROCUREMENTS TO BE FOR ONLY SOLAR PAIRED WITH STORAGE RESOURCES AND EXCLUDE SOLAR ONLY RESOURCES?[33]

A. No. The Commission should not preemptively exclude a low-cost carbon-free technology like solar-only resources from future procurements. It is premature at this time to rule out the potential value, benefits, and savings to customers of solar-only generators. To be clear, the Companies are planning for a significant portion of new solar resources procured in future procurements to include storage of potentially varying configurations. The

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[33] CCEBA DiFelice Direct Testimony at 20.

Modeling and Near-Term Actions Panel also addresses this issue from a modeling perspective and highlights that the Companies would need to procure 1,200 MW of solar paired with storage in 2023-2024 to reach the 600 MW paired storage target in the near-term action plan, assuming all future solar paired with storage includes storage that is 50% of the solar nameplate capacity.

B. Standalone Storage Procurement

Q. TURNING NOW TO STANDALONE STORAGE, DO YOU BELIEVE THAT PROCUREMENT OF STANDALONE STORAGE SHOULD FOLLOW THE EXACT SAME CONSTRUCT AS THE PROCUREMENT OF SOLAR AND SOLAR PAIRED WITH STORAGE?

A. No. For the reasons explained further below, I do not believe that standalone storage should be procured in the same manner as solar and solar paired with storage.

Q. DO THE COMPANIES USE COMPETITIVE SOURCING FOR THEIR DEVELOPMENT OF STANDALONE STORAGE?[34]

A. Yes, the Companies regularly use competitive sourcing opportunities for standalone storage projects, such as RFPs for engineering, procurement, and construction ("EPC") offers and for equipment and materials. This process ensures low costs for customers through market competition.

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[34] *See* CCEBA DiFelice Direct Testimony at 21.

Q. PLEASE DIFFERENTIATE BETWEEN EPC THAT THE COMPANIES ROUTINELY USE FOR STANDALONE STORAGE AS OPPOSED TO THE BUSINESS MODEL OF "THIRD-PARTY DEVELOPERS."

A. The EPC companies that the Companies routinely use for standalone storage offer a core competency in the engineering, procurement, and construction of projects. (Third-Party Developers also typically use an EPC.) Generally, the EPC companies do not perform the early-stage activities of battery development, such as handling project identification or evaluation, buying/selling any of the land, preparing engineering designs or interconnection agreements, obtaining permits, or establishing off-take sales agreements associated with new construction battery projects. An EPC company's role generally begins after these early-stage activities have been completed.

In contrast, a third-party developer does generally perform these early-stage activities of battery development. If the third-party developer intends to sell the asset, it may do so at varying stages of project development with a willing off-taker. In a build-own-transfer arrangement, the third-party developer also hires and oversees the EPC. If a sale is contemplated prior to asset construction, the third-party developer may perform some or all of the early-stage development activities.

For a self-developed Duke standalone storage project, the Companies would perform these early-stage activities of battery development.

Q. DO YOU AGREE WITH WITNESS DiFELICE THAT THIRD-PARTY DEVELOPERS CAN CREATE BUILD-OWN-TRANSFER PROJECTS MORE COST-EFFECTIVELY THAN DUKE ENERGY?[35]

A. No. There is no compelling evidence to suggest that a developer stepping in as an intermediary to create a build-own-transfer structure for batteries is more cost-effective than a utility self-developing the battery project.

Q. DOES DUKE ENERGY AGREE WITH WITNESS DiFELICE THAT ALLOWING THIRD-PARTY DEVELOPERS TO PARTICIPATE IN STAND-ALONE ENERGY STORAGE DEPLOYMENT WILL INCREASE THE SPEED AT WHICH THE RESOURCES COME ONLINE?[36]

A. No. Allowing third-party developers to participate in stand-alone storage will not increase the speed that batteries can come online because the storage facilities are still subject to the same interconnection cluster processes and timelines. Utilizing existing utility-owned land and siting utility self-developed batteries near existing or retiring utility generators, on the other hand, offers advantages in shortening the deployment timeline,

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[35] CCEBA DiFelice Direct Testimony at 9.
[36] CCEBA DiFelice Direct Testimony at 9.

either from interconnection study or minimizing construction of interconnection facilities. This is in sharp contrast to the majority of solar generation projects because, in those cases, the developer already has site control that is not available to the Companies.

Q. ARE THERE ADVANTAGES TO THE COMPANIES SELF-DEVELOPING STANDALONE STORAGE PROJECTS RATHER THAN PROCURING THROUGH BUILD-OWN-TRANSFER AGREEMENTS?[37]

A. Yes. There are many advantages to the Companies developing and managing the construction of their standalone storage facilities. First and foremost, I want to emphasize that self-development does not mean the Companies will not leverage third-party expertise and utilize RFP practices to drive down prices—as stated above, we have a long track record of leveraging third-party expertise and RFPs across our entire business, including standalone storage. However, since the footprint for storage is not as dependent on geography as for renewable resources or even thermal generators, the Companies are seeking to site future battery projects based on existing grid assets, proximity to load centers, and available land at existing sites to reduce the complexity and cost of developing these batteries. This integrated planning approach is focused on leveraging existing assets to lower costs for customers, while also avoiding the cost to

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[37] CCEBA DiFelice Direct Testimony at 9.

customers of adding an intermediary to perform the role of project managing the construction before selling the project to Duke Energy.

Incremental solar is very different, since it is needed to create additional carbon-free energy and typically requires that new land be utilized to produce the new energy. Additionally, self-developing battery storage projects facilitates implementation of these resources' evolving safety and design standards, which are not mandatory or consistent across the country. The Companies continue to enhance the community engagement and fire safety efforts around batteries, and would be hamstrung to change safety standards or requirements of a build own transfer project at any point after the contract was executed, even when new recommendations are established in the industry. For example, after the Arizona Public Service battery fire in 2019, DEP paused development efforts at the Hot Springs Microgrid project and the Asheville Rock Hill battery to learn more about the incident from industry peers and subject matter experts in order to incorporate new fire safety measures into the project design. The Company was able to take these reasonable actions because it was self-developing the project and was not contractually limited to the pre-specified safety measures.

By self-developing standalone storage assets, Duke Energy is able to closely oversee construction quality and safety as well as effectively negotiate warranties and performance guarantees based on a flexible future use.

Q. IS STANDALONE STORAGE APPROPRIATE FOR AN OPEN BUILD-OWN-TRANSFER PROCUREMENT PROCESS AT THIS TIME?[38]

A. The Companies support all available avenues to keep customer costs low, and would be open to further exploring options for a future build-own-transfer RFP for standalone storage. In such a scenario, the RFP would be subject to Duke Energy-directed siting based on system needs, benefits, timing, and other requirements. The technical requirements for a standalone storage acquisition RFP would be very specific, including approved vendors and equipment, design standards, safety requirements, capacity and energy content, and appropriate use case-driven capabilities. The Companies continue to believe that a BOT model may not be appropriate or feasible in all scenarios but the Companies would, in every case, utilize competitive sourcing processes for the benefit of customers.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[38] CCEBA DiFelice Direct Testimony at 21.

CERTIFICATE OF SERVICE

I certify that a copy of the Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's *Corrections to Transmission and Solar Procurement Panel Rebuttal Testimony,* in Docket No. E-100, Sub 179, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid, to parties of record.

This the 27th day of September, 2022.

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