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JUN 03 2022

June 3, 2022

VIA Electronic Filing

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

*Re: Response to Order Requiring Answers to Commission Questions
Docket Nos. E-2, Sub 1297 and E-7, Sub 1268*

Dear Ms. Dunston:

Enclosed for filing in the above-referenced proceedings on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC is their Response to Order Requiring Answers to Commission Questions.

Please do not hesitate to contact me should you have any questions. Thank you for your assistance with this matter.

Very truly yours,

/s/E. Brett Breitschwerdt

EBB:kjg

Enclosure

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the Part A Price. For example, if the bidder's assumed System Upgrades cost identified in the Interconnection Agreement is \$1.50 million and the submitted Part B Price adjuster is \$1/MWh per \$1 million in costs, then the Contract Price Adder to the Part A Price would be \$1.50/MWh (\$1.50 million of upgrades x \$1/MWh).

For the purpose of ranking bids, Controllable PPA Proposals in which it is lower cost for customers for Duke Energy to fund the System Upgrades, the total System Upgrade costs (in dollars) will be spread over the MWh over the 25-year life of the contract, based on the production profile and degradation rate. These upgrades costs are then imputed to the bid price to calculate the full cost of the Proposal, inclusive of System Upgrade estimates.

For Utility Ownership Track, the System Upgrade costs will be spread over the MWh over the 30-year life of the asset based on the production profile and degradation rate. These upgrade costs are then imputed to the calculated LCOE to arrive at the full cost of the Proposal, inclusive of System Upgrade estimates.

In Step 1 of the bid evaluation process, the DISIS Phase 1 System Upgrade cost estimates assigned to each Proposal will be used to establish initial rankings. In Step 2, those costs will be updated based upon the costs assigned to each Proposal in DISIS Phase 2

For PPA Track Proposals with executed Interconnection Agreements that bid into the RFP, the System Upgrade costs are embedded in the "Part A Price," and therefore are also implicitly captured in the evaluation process. Utility Ownership Track Proposals with executed Interconnection Agreements will provide the interconnection cost estimates in their bid submission, which are included in the project evaluation.

Commission Question 2: Identify any System Upgrade projects that will be included in the baseline for 2022 DISIS that: i) were identified in the TCS; ii) were referenced in the Carbon Plan or the 2022 NCTPC Study Scope Document; or iii) were previously identified as network upgrades that would have been assigned to an interconnection customer.

Duke Energy Response:

Generator interconnection studies are performed using current assumptions of system conditions at the relevant snapshot year that the study is examining. The assumptions for the interconnection studies include contingent facilities¹ associated with earlier queued Interconnection Customers and planned transmission expansion facilities, including those approved through Duke Energy's transmission planning process under Attachment N-1 of the OATT.² The 2022 NCTPC Study Scope Document³ does not identify specific upgrades

¹ See Joint OATT, Attachment J, Section 1 (Definitions) ("Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.").

² Information on Base Case Data used in generator interconnection studies can be requested on the Companies' OASIS website.

³ http://www.nctpc.org/nctpc/document/REF/2022-05-10/2022_NCTPC_Study_Scope_05_10_2022_FINAL_DRAFT.pdf

and instead covers more general aspects like purpose, process, generation assumptions (subject to updating), and study scenarios.

The 2022 DISIS generator interconnection baseline will include all of the transmission infrastructure and earlier queued generators that are expected (as of the beginning of the applicable DISIS phase) to be completed before the year(s) and seasons being evaluated.

In response to the three categories of Upgrade projects identified by the Commission:

i) Upgrades identified in Transitional Cluster Study (“TCS”): No major network upgrades identified (and assigned to TCS generators) from TCS Phase 1 study will be included in the 2022 DISIS baseline due to numerous TCS generator interconnection customers withdrawing after Phase 1 of the TCS.⁴

ii) Red Zone Transmission Expansion Plan Upgrades: As noted in the Commission’s Order, Appendix P to the Carbon Plan provides an overview of the Companies’ local and regional transmission planning processes. Table P-3 specifically identifies Red Zone Transmission Expansion Plan (“RZEP”) projects as necessary to achieve public policy objectives associated with interconnecting new renewable energy generation in constrained areas of the DEP and DEC transmission systems, in addition to providing other benefits such as increased reliability, added resilience, and improved transfer capability between DEC and DEP. These RZEP projects were identified based on recent generator interconnection studies and are now being recommended for approval through the North Carolina Transmission Planning Collaborative (“NCTPC”) local transmission planning process.

Specifically, the Companies are proposing the RZEP projects as part of the mid-year update to the approved 2021 NCTPC Local Transmission Plan.⁵ In addition to introducing these RZEP projects in the Carbon Plan, DEC and DEP recently posted the RZEP project lists to their OASIS sites and explained that the projects will be considered through the NCTPC.⁶ Duke Energy also highlighted that, to date, these RZEP projects have not yet received stakeholder input through the NCTPC Transmission Advisory Group nor have the RZEP projects yet been approved by the Oversight Steering Committee. If the NCTPC Oversight Steering Committee approves the DEC and DEP RZEP projects and they are included in the updated 2021 NCTPC Local Transmission Plan either before or during DISIS, then to the extent a particular project proposal would depend on the RZEP project for a reliable interconnection, that particular RZEP project would become a “contingent facility” for the generator in DISIS and the costs of these transmission system improvements would not be allocated to the generator requesting interconnection in the 2022 DISIS Cluster (whether participating in 2022 SP RFP or not).

⁴ To the extent that the TCS upgrades are also part of the Red Zone upgrades noted below, they could be part of the baseline.

⁵ The approved 2021 NCTPC Collaborative Transmission Plan and prior mid-year update documents can be accessed via the reference documents tab on the NCTPC’s website, accessible at: <http://www.nctpc.org/nctpc/listDocument.do?catId=REF>

⁶ See Attachment 1 available at www.oasis.oati.com/duk/ under the “Transmission Planning” “TPCA and NCTPC Reports” subfolder and at www.oasis.oati.com/cpl/ under the “Transmission Planning” folder.

To the extent that generators in DISIS require approved Local Transmission Plan upgrades to interconnect, those generators would be contingent upon the relevant network upgrades, but the costs of those contingent facilities would not be directly assigned to those generators in the DISIS Cluster.

iii) Network Upgrades that would have been assigned to Interconnection Customer that withdrew: The RZEP projects referenced in Carbon Plan Appendix P, Table P-3 were identified based on previous interconnection studies for interconnecting customers that did not move forward to interconnect, so this category of upgrade is not “included in the baseline” per se, but have informed and are included in the RZEP projects (which, as explained above, may be included in the baseline).

Commission Question 3: For any System Upgrade projects identified in the answer to Question No. 2, explain how including the identified upgrades in the baseline for the 2022 DISIS will impact the 2022 procurement process, paying particular attention to whether such inclusion has the potential to impact the cost-effectiveness of bids.

Duke Energy Response:

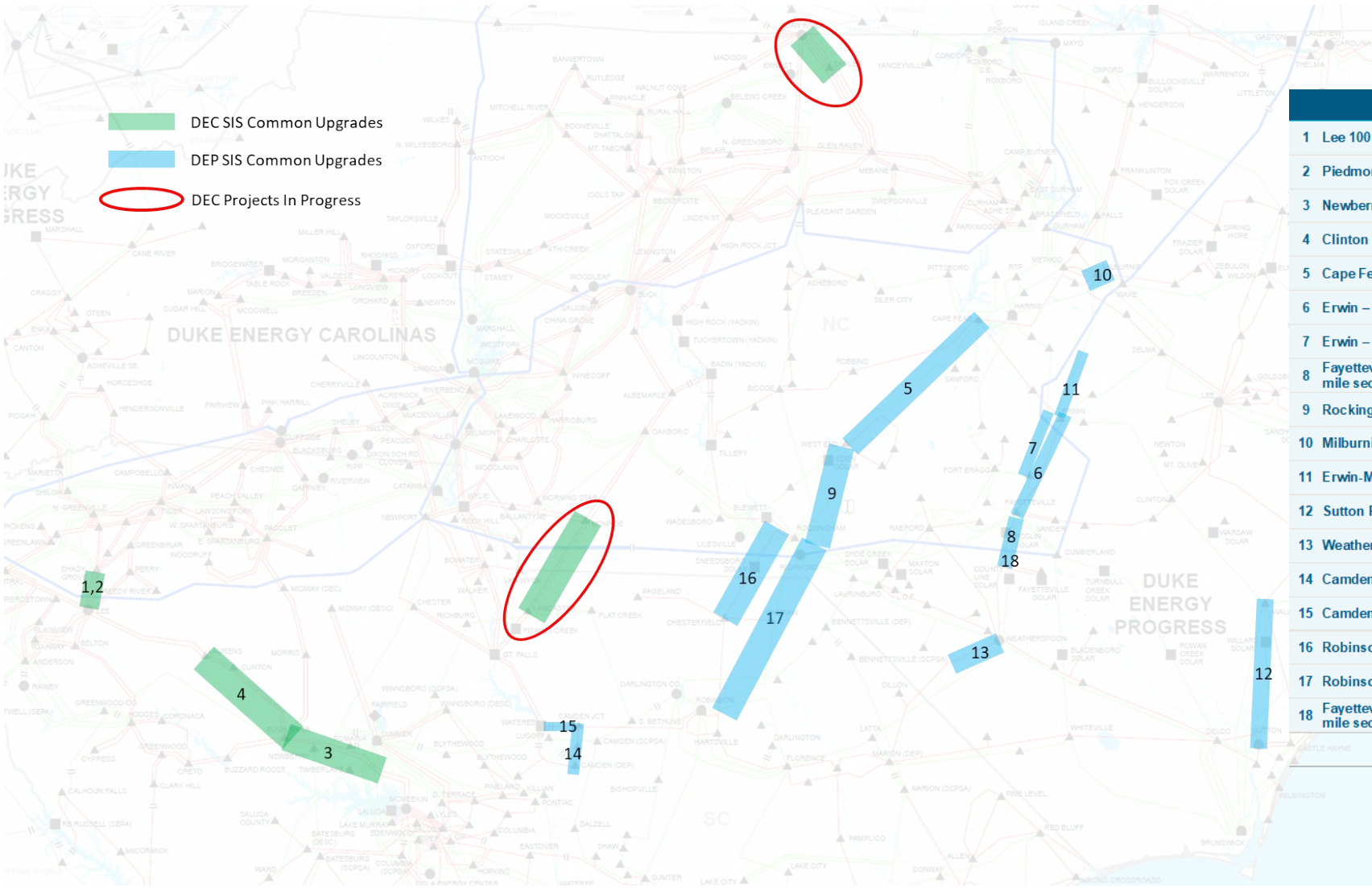
If the NCTPC Oversight Steering Committee approves the RZEP projects for inclusion in the NCTPC’s 2022 mid-year update (to the 2021 NCTPC Plan), those transmission projects would become part of the Companies’ Local Transmission Plan and the cost of those projects would not be allocated to generators requesting interconnection in the 2022 DISIS. For example, if a 2022 SP Program Proposal is reliant on an RZEP upgrade, the relevant RZEP upgrade would be a “contingent facility” for that generator, and the generator would have lower System Upgrade costs assigned to them in DISIS relative to the costs that would be assigned if those upgrades were not being planned and constructed as part of the Companies’ Local Transmission Plan. This is consistent with how cost will be assigned for all planned upgrades in the Local Transmission Plan upon which a generator’s project is dependent and is also consistent with the Companies’ past practice for coordinating interaction between planned upgrades in the local transmission planning process and upgrades required for generator interconnections. Additionally, all projects in the DISIS Cluster, whether being offered as a Proposal in the 2022 SP Program or not, will be treated the same in terms of how the RZEP projects (if approved) are assumed in the DISIS baseline so there is no discriminatory treatment between Interconnection Customers.

If the RZEP projects are approved and included in the baseline, the Companies expect this will help to alleviate the risk of cascading drop-outs and cost re-allocation, as happened in the TCS. As most recently seen in the TCS, even a very large quantity of generators in the queue was not sufficient to move a subset of the RZEP upgrades forward; instead, approximately 30 Interconnection Customers totaling approximately 1800 MW of new solar generation in DEP East withdrew from the TCS. Past studies indicate that the RZEP projects could enable approximately 2,900 additional MW of solar if located in the appropriate geographic regions, which will be critical to achieving the Companies’ carbon goals and maintaining the reliability of the transmission system for anticipated future generator interconnections.

DEC and DEP Red Zone Transmission Expansion Plan

- Slide 2 reflects proposed DEC and DEP Red Zone Transmission Expansion Plan projects being screened by the North Carolina Transmission Planning Collaborative Local Transmission Planning process
- These projects will receive and consider stakeholder input through the NCTPC Transmission Advisory Group
- A Local Transmission Plan incorporating these projects is contingent on the NCTPC Oversight Steering Committee endorsing the Local Transmission Plan

DEC and DEP Red Zone Transmission Expansion Plan



Project	Owner	Project Description	Total Cost (FB, w/ contingency)	Estimate Class
1 Lee 100 kV (Lee-Shady Grove)	DEC	Upgrade	\$45,000,000	5
2 Piedmont 100 kV (Lee-Shady Grove)	DEC	Upgrade	\$45,000,000	5
3 Newberry 115 kV (Bush River-DE SC)	DEC	Upgrade	\$42,000,000	5
4 Clinton 100 kV (Bush River-Laurens)	DEC	Upgrade	\$109,000,000	5
5 Cape Fear Plant – West End 230kV Line	DEP	Rebuild	\$70,349,010	4
6 Erwin – Fayetteville East 230kV Line	DEP	Rebuild	\$83,933,750	4
7 Erwin – Fayetteville 115kV Line	DEP	Rebuild	\$21,288,975	4
8 Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	DEP	Rebuild	\$14,106,625	4
9 Rockingham – West End 230kV West Line	DEP	Upgrade	\$1,457,875	4
10 Milburnie 230kV Substation	DEP	Redundant Bus Protection	\$4,324,127	4
11 Erwin-Milburnie 230kV Line	DEP	Rebuild	\$5,300,000	5
12 Sutton Plant-Wallace 230kV Line	DEP	Upgrade	\$500,000	5
13 Weatherspoon-Marion 115kV Line	DEP	Rebuild	\$13,000,000	5
14 Camden-Camden Dupont 115kV Line	DEP	Rebuild	\$2,600,000	5
15 Camden Junction-DPC Wateree 115kV Line	DEP	Rebuild	\$10,000,000	5
16 Robinson Plant-Rockingham 115kV Line	DEP	Rebuild	\$38,000,000	5
17 Robinson Plant-Rockingham 230kV Line	DEP	Rebuild	\$43,100,000	5
18 Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	DEP	Rebuild	\$11,600,000	5
Total			\$560,560,362	

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CERTIFICATE OF SERVICE

I hereby certify that copies of the Response to Order Requiring Answers to Commission Questions, as filed in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, were served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 3rd day of June, 2022.

/s/ E. Brett Breitschwerdt

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