Purpose of Study

The purpose of this study is to assess the Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") transmission systems' reliability and develop a single collaborative transmission plan for the DEC and DEP transmission systems that ensures reliability of service in accordance with NERC, SERC, DEC, and DEP requirements. In addition, the study will also assess Local Economic Study option scenarios and/or Public Policy Study requests provided by the Transmission Advisory Group ("TAG") and approved for study by the Oversight Steering Committee ("OSC"). The Planning Working Group ("PWG") will perform the technical analysis outlined in this study scope under the guidance and direction of the OSC.

No Local Economic Study requests were received and two Public Policy requests were received from TAG stakeholders by the February 8th deadline for the 2023 study year.

The first Public Policy Study request was submitted on behalf of the Carolinas Clean Energy Business Association, the Clean Power Suppliers Association, the North Carolina Sustainable Energy Association, the Southern Alliance for Clean Energy, the Southern Environmental Law Center (including non-TAG interested party Natural Resources Defense Council), and the Sierra Club (collectively, the Participants). This Public Policy Request proposed an analysis of high volumes of solar and solar plus storage to determine DEC and DEP transmission system impacts and possible strategic transmission implications for local transmission projects. Specifically, the TAG Participants Public Policy Request is for a study of 9.3GW and 12.5GW of additional solar and solar plus storage with a 2033 Summer case with resource additions and generation retirements to be aligned with the 2022 Carbon Plan P1 Portfolio.

The second Public Policy Study request submitted on behalf of the Public Staff proposed an analysis to evaluate transmission impacts from generation retirements and resource supply additions as provided in the 2022 Carbon Plan Portfolios. In the Public Staff's view, at some point in the future, the integration of new supply resources and retirement of older generation would probably require greenfield 230 kV and/or 500 kV transmission lines to be constructed and placed in service to support economic bulk energy transfers and to maintain or improve reliability. This study is intended to identify the future year(s) that it is projected that greenfield 230 kV and/or 500 kV transmission lines would be needed. This study would also utilize the 2033 Summer case and 2033/2034 Winter case with resource additions and generation retirements to be aligned with the 2022 Carbon Plan P1 Portfolio.

Overview of the Study Process Scope

The scope of the proposed study process will include the following steps:

1. **Study Assumptions**
   - Study assumptions selected.
2. **Study Criteria**
   - Establish the criteria by which the study results will be measured.
3. **Case Development**
   - Develop the models needed to perform the study.
   - Determine the different resource supply scenarios to evaluate.
4. **Methodology**
   - Determine the methodologies that will be used to carry out the study.
5. **Technical Analysis and Study Results**
   - Perform the study analysis and produce the results. Initially, power flow analyses will be performed based on the assumption that thermal limits will be the controlling limit for the reliability plan. Voltage, stability, short circuit and phase angle studies may be performed if circumstances warrant.
6. **Assessment and Problem Identification**
   - Evaluate the results to identify problems/issues.
7. **Solution Development**
   - Identify potential solutions to the problems/issues.
   - Test the effectiveness of the potential solutions through additional studies and modify the solutions as necessary such that all reliability criteria are met.
   - Perform a financial analysis and rough scheduling estimate for each of the proposed solutions (e.g., cost, cash flow, present value).
8. **Selection of a Recommended Collaborative Transmission Plan**
   - Compare alternatives and select the preferred solution alternatives – balancing cost, benefits and risks.
   - Select a preferred set of transmission improvements that provide a reliable transmission system to customers most cost effectively while prudently managing the associated risks.

9. **Report on the Study Results**
   - Prepare a report on the recommended Collaborative Transmission Plan.

Each of these study steps is described in more specific detail below.

Study Assumptions

The specific assumptions selected for the 2023 Study are:

- The study will combine the Public Policy Requests into one set of inputs for study over multiple years (2028 Summer, 2028/2029 Winter, 2033 Summer, and 2033/2034 Winter) evaluating transmission impacts associated with the Public Policy Request objectives.
- The years to be studied (study years) will be 2028 Summer and 2028/2029 Winter for a near term reliability analysis and 2033 Summer and 2033/2034 Winter for a longer-term reliability analysis. Each Load Serving Entity ("LSE") will provide a list of resource supply assumptions and include the resource dispatch order for each of its Designated Network Resources in the DEC and DEP control areas. Generation will be dispatched for each LSE in the cases to meet that LSE's peak load in accordance with the designated dispatch order. LSEs will also include generation down scenarios for their resources, if applicable (e.g., generation outage with description of how generation will be replaced, such as by that LSE's dispatch orders).
- PSS/E and/or TARA will be used for the study.
- Load growth assumptions will be in accordance with each LSE's practice.
- Generation, interchange and other assumptions will be coordinated between Participants as needed.
- The tables below list the major generation facility additions and retirements assumed to occur by 2028 Summer, 2028/2029 Winter, and 2033 Summer and 2033/2034 Winter.
- The retirements and resource additions modeled in the study are generally based on portfolios in the Carbon Plan approved by the North Carolina Utilities Commission in its December 31, 2022 order.

Major Generation[2] Facility Additions in 2023 Study

Company	Generation Facility	2028S	2028/ 2029W	2033S	2033/ 2034 W
DEC	Lincoln County CT (525 MW)	Included	Included	Included	Included
DEC	Apex PV (30 MW)	Included	Included	Included	Included
DEC	Aquadale PV (50 MW)	Included	Included	Included	Included
DEC	Bear Branch PV (35 MW)	Included	Included	Included	Included
DEC	Beaverdam PV (42 MW)	Included	Included	Included	Included
DEC	Blackburn PV (61.7 MW)	Included	Included	Included	Included
DEC	Brookcliff PV (50 MW)	Included	Included	Included	Included
DEC	Healing Springs PV (55 MW)	Included	Included	Included	Included
DEC	Hornet PV (75 MW)	Included	Included	Included	Included
DEC	Misenheimer PV (74.4 MW)	Included	Included	Included	Included
DEC	Oakboro PV (40 MW)	Included	Included	Included	Included
DEC	Olin Creek PV (35 MW)	Included	Included	Included	Included
DEC	Partin PV (50 MW)	Included	Included	Included	Included
DEC	Pelham PV (32 MW)	Included	Included	Included	Included
DEC	Quail PV (30 MW)	Included	Included	Included	Included
DEC	Two Hearted PV (22 MW)	Included	Included	Included	Included
DEC	West River PV (40 MW)	Included	Included	Included	Included
DEC	Westminster PV (75 MW)	Included	Included	Included	Included

[2] Major Generation Threshold is considered to be 10 MW or greater and connected to the transmission system

Major Generation[2] Facility Additions in 2023 Study

Company	Generation Facility	2028S	2028/ 2029W	2033S	2033/ 2034 W
DEP	Cabin Creek Solar (70.2 MW)	Included	Included	Included	Included
DEP	Gold Valley Solar (78.8 MW)	Included	Included	Included	Included
DEP	Nutbush Solar (35.0 MW)	Included	Included	Included	Included
DEP	Camp Lejeune Battery (11.0 MW)	Included	Included	Included	Included
DEP	Sapony Creek (23.4 MW)	Included	Included	Included	Included
DEP	Loftins Crossroads (75.0 MW)	Included	Included	Included	Included

Major Generation[2] Facility Retirements in 2023 Study

Company	Generation Facility	2028S	2028/ 2029W	2033 S	2033/ 2034W
DEC	Allen 1-5 (1083 MW)	Retired	Retired	Retired	Retired
DEC	Lee 3 (120 MW)	Retired	Retired	Retired	Retired
DEP	Blewett CTs 1-4 and Weatherspoon CTs 1- 4 (232 MW)	Retired	Retired	Retired	Retired

[2] Major Generation Threshold is considered to be 10 MW or greater and connected to the transmission system

Additional Major Generation[2] Facility Additions in the Public Policy Request Study Scope

Company	Generation Facility	2028S	2028/ 2029W	2033S	2033/ 2034 W
DEC	Marshall Plant CT (752 MW)	Not Included	Included	Included	Included
DEC	Marshall Plant CC (1216 MW)[3]	Not Included	Included	Included	Included
DEC	Marshall Plant SMR (285 MW)	Not Included	Not Included	Included	Included
DEC	Bad Creek Phase II (1680 MW)	Not Included	Not Included	Included	Included
DEP	Roxboro CT (752 MW)[3]	Not Included	Included	Included	Included
DEP	Roxboro CC Unit 1 (1216 MW)	Not Included	Included	Included	Included
DEC/ DEP	Solar, Wind, and Storage (see further details below)	Included	Included	Included	Included

Additional Major Generation[2] Facility Retirements in the Public Policy Request Study Scope

Company	Generation Facility	2028S	2028/ 2029W	2033S	2033/ 2034 W
DEC	Cliffside 5 (574 MW)	Retired	Retired	Retired	Retired
DEC	Marshall 1,2 (760 MW)	Not Retired	Retired	Retired	Retired
DEC	Marshall 3,4 (1318 MW)	Not Retired	Not Retired	Retired	Retired
DEP	Roxboro Units 1-4 (2462 MW)	Not Retired	Not Retired	Retired	Retired
DEP	Mayo Unit 1 (746 MW)	Not Retired	Not Retired	Retired	Retired

[2] Major Generation Threshold is considered to be 10 MW or greater and connected to the transmission system

[3] Additional Generation if needed to meet peak load demand

- The Public Policy Request study will analyze the transmission impacts from resource supply additions and generation retirements (in no particular order).

1) Portfolio P1 retirement of coal generation
    a. DEC will model the retirement of Allen 1-5, Cliffside 5, Lee 3, Marshall 1-4
    b. DEP will model the retirement of Roxboro 1-4, Mayo 1, Weatherspoon CTs, and Blewett CTs.

2) The incremental resource supply additions for the 9.3 GW and 12.5 GW of additional solar and solar plus storage scenarios will be in accordance with the P1-modified tables below for each of the Duke Energy Balancing Authority Areas (numbers are nameplate output). These resource MW levels represent 30%/70% DEC/DEP ratio. The 12.5 GW analysis will be performed first, and the results are expected to be completed this year and reported on in the annual transmission plan report at the end of the year. Analysis of the 9.3 GW scenario will be performed later, and if not completed in time, the results may be presented outside of the annual transmission plan report. This 9.3 GW analysis may include power flow runs or, alternatively, the results may be based on a review of the 12.5 GW results and removal of the highest interconnection cost solar plants based on thermal network upgrades ($/W) and engineering judgement. This will be determined once the 12.5 GW analysis results are completed and analyzed to determine the best approach for completing the 9.3 GW analysis.

3) Addition of Onshore wind generation
    a. DEC and DEP will model onshore wind generation with twelve 100 MW points of interconnection, 2 in DEC and 10 in DEP.

4) Addition of Offshore wind generation
    a. DEP will model an additional 800 MW of offshore wind generation with New Bern 230 kV Substation as the point of interconnection.

5) Addition of new gas CC and CT generation
    a. DEC will model the addition of 1216 MW of combined cycle gas generation at Marshall Plant 230 kV Switchyard if needed to meet peak demand.
    b. DEP will model the addition of 1216 MW of combined cycle gas generation at Roxboro Plant 230 kV Switchyard.
    c. DEC will model 752 MW of new CTs at Marshall Plant 230kV Switchyard and consider the upgrade of the Westport 230 kV Line.
    d. DEP will model 752 MW of new CTs at Roxboro Plant 230kV Switchyard if needed to meet peak demand.

6) Addition of 1680 MW of Pumped Storage Hydro Bad Creek II Expansion

7) Addition of a 285 MW SMR at Marshall Plant 230kV Switchyard

8) Standalone storage above levels presented in the tables below can be added on a 50%/50% DEC/DEP ratio as determined to be needed. Standalone battery storage can be deployed on the primary transmission voltages, 100 kV thru 230 kV, and connected at transmission substations near major load centers (e.g., Raleigh, Wilmington, Charlotte, Spartanburg, Asheville, etc.).

9) Reliability CTs can be added as needed at existing generating facility sites such as near Rockingham Plant for DEC and within Person County for DEP.

Portfolio P1-modified to reflect 12.5 GW of incremental solar and solar plus storage by 2033 Summer (DEC/DEP split = 30%/70%).

12.5GW of Incremental Solar and Solar plus Storage by 2033 Summer

DEC	Coal Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2033 S	-3050	2900	850	100	1063	367	1216	752	0	285	1680
2033/2034 W	-3050	3284	1265	200	1063	367	1216	752	0	285	1680

12.5GW of Incremental Solar and Solar plus Storage by 2033 Summer

DEP	Coal Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2033 S	-3175	2100	6650	800	1013	1360	1216	752	800	0	0
2033/2034 W	-3175	2200	7608	1000	1213	1640	1216	752	800	0	0

SPS - Solar plus Storage – The target MWs is solar. Thus 1000 MW solar plus storage implies 1000 MW of nameplate solar plus a lesser amount (e.g., 30% - 40% of solar nameplate MW) of storage.

Battery paired with Solar – The target MW is battery storage (e.g., 4-hr Li-ion battery storage). Thus 1000 MW battery paired with solar implies 1000 MW of nameplate battery storage with some amount of co-located solar.

Study Criteria

The study criteria used will promote consistency in the planning criteria used across the systems of the Participants, while recognizing differences between individual systems. The study criteria will consider the following reliability elements:

- NERC Reliability Standard requirements
- SERC requirements
- Individual company criteria (voltage, thermal, stability, short circuit and phase angle)

Case Development

- The most current MMWG system models will be used for the systems external to DEC and DEP as a starting point for the Base Case.
- The Base Case will include the detailed internal models for DEC and DEP and will include current transmission additions planned to be in-service for the given year (e.g., in-service by summer 2033 for 2033S cases and in-service by the winter for 2033/2034W cases).
- An "All Firm Transmission" Case(s) will be developed which will include all confirmed long term firm transmission reservations with roll-over rights applicable to the study year(s).
- DEC and DEP will each create their respective generation down cases from the common Base Case and share the relevant cases with each other.

Study Methodology

DEC and DEP will exchange contingency and monitored element files so that each can test the impact of the other company's contingencies on its transmission system. Initially, power flow analyses will be performed based on the assumption that thermal limits will be the controlling limit for the reliability plan. Voltage, stability, short circuit and phase angle studies may be performed if circumstances warrant.

Technical Analysis and Study Results

The technical analysis will be performed in accordance with the study methodology. Results from the technical analysis will be reported throughout the study area to identify transmission elements approaching their limits such that all Participants are aware of potential issues and appropriate steps can be identified to correct these issues, including the potential of identifying previously undetected problems.

DEC and DEP will report results throughout the study area based on:

- Similar to Cluster Study criteria, thermal loadings greater than 95%.
- Voltages less than 100% for 500 kV and less than 95% for 230 kV, 161 kV, 115 kV, and 100 kV buses; pre- to post-contingency voltage drops of 5% or more.

Assessment and Problem Identification

- Each utility will utilize its own reliability criteria for its own transmission facilities. Each utility will document the reliability problems resulting from its assessments. These results will be reviewed and discussed with the TAG for feedback.

Solution Development

- The PWG will develop potential solution alternatives to the identified reliability problems.
- The TAG will have the opportunity to propose solution alternatives to the identified reliability problems.
- DEC and DEP will test the effectiveness of the potential solution alternatives using the same cases, methodologies, assumptions and criteria described above.
- DEC and DEP will develop rough, planning-level cost estimates and construction schedules for the solution alternatives.

Selection of a Recommended Collaborative Transmission Plan

- The PWG will compare alternatives and select the preferred solution alternatives, balancing costs, benefits and risks.
- The PWG will select a preferred set of transmission improvements that provides a reliable and cost-effective transmission solution to meet customers' needs while prudently managing the associated risks.
- The preferred set of transmission improvements developed by the PWG will be reviewed and discussed with the TAG for feedback.

Report on the Study Results

The PWG will compile all the study results and prepare a recommended collaborative plan for OSC review and approval. Prior to the OSC's final review and approval, the final draft of the study report will be reviewed and discussed with the TAG members to solicit their input on the recommended collaborative plan. The final report will include a comprehensive summary of all the study activities as well as the recommended transmission improvements including estimates of costs and construction schedules.