North Carolina Transmission Planning Collaborative

Report on the NCTPC 2021–2031 Collaborative Transmission Plan

January 24, 2022
FINAL REPORT

2021 – 2031 NCTPC Transmission Plan
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I. Executive Summary

The North Carolina Transmission Planning Collaborative ("NCTPC") was established to:

1) provide the Participants (Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), North Carolina Electric Membership Corporation ("NCEMC"), and ElectriCities of North Carolina ("ElectriCities") and other stakeholders an opportunity to participate in the electric transmission planning process for the areas of North Carolina and South Carolina served by the Participants;

2) preserve the integrity of the current reliability and least-cost planning processes;

3) expand the transmission planning process to include analysis of increasing transmission access to supply resources inside and outside the Balancing Authority Areas ("BAAs") of DEC and DEP; and

4) develop a single coordinated transmission plan for the Participants that includes Reliability and Local Economic Study Transmission Planning while appropriately balancing costs, benefits and risks associated with the use of transmission and generation resources.

The overall NCTPC Process is performed annually and includes the Reliability Planning and Local Economic Study Planning Processes, which are intended to be concurrent and iterative in nature. The NCTPC Process is designed such that there will be considerable feedback and iteration between the two processes as each effort's solution alternatives affect the other's solutions.

The 2020–2030 Collaborative Transmission Plan (the "2020 Collaborative Transmission Plan" or the "2020 Plan") was published in January 2020.

This report documents the current 2021 – 2031 Collaborative Transmission Plan ("2021 Collaborative Transmission Plan" or the "2021 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2021 reliability planning study scope and methodology. The NCTPC Process document and 2021 Study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2021 reliability planning process is focused on the annual base reliability study. The base reliability study assesses the reliability of the transmission systems of both DEC and DEP in order to ensure reliability of service in accordance with North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation ("SERC"), and DEC and DEP requirements. The purpose of the base reliability study is to evaluate the transmission systems' ability to meet load growth projected for 2021 through 2031 with the Participants' planned Designated Network Resources ("DNRs").

Based on the study's input assumptions, the 2021 Study identifies any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2021 Study also makes adjustments to existing plans where necessary.

The NCTPC reliability study results affirm that the planned DEC and DEP transmission projects identified in the 2020 Plan continue to satisfactorily address the reliability concerns identified in the 2020 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2021 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

The total estimated cost for the 16 reliability projects included in the 2021 Plan is $694 million as documented in Appendix B. This compares to the original 2020 Plan estimate of $804 million for 17 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. An update to the 2020 plan was provided in the 2021 mid-year update published in June 2021 with an updated cost estimate of $846 million. See Appendix D for a detailed comparison of this year's Plan to the updated 2020 Plan.

The list of major projects will continue to be modified on an ongoing basis as new improvements are identified through the NCTPC Process and projects are placed in-service or eliminated from the list. Appendix C provides a more detailed description of each project in the 2021 Plan.

The 2021 Plan, relative to the 2020 Plan, includes 3 new DEC projects:

- Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Add Second Circuit
- Monroe 100 kV Line (Lancaster-Monroe), Upgrade
- Westport 230 kV Line (McGuire-Marshall), Upgrade

The 2021 Plan, relative to the 2020 Plan, includes no new DEP projects.

There are revised in-service dates, estimated cost changes, and/or scope changes for the following DEC and DEP projects:

- Sutton–Castle Hayne 115 kV North line project was placed in-service.
- Asheboro–Asheboro East 115 kV North Line project had a decrease in estimated cost.
- Windmere 100 kV Line (Dan River–Sadler) project had an increase in estimated cost and its in-service date was pushed out.
- Craggy–Enka 230 kV Line project had a decrease in estimated cost and the in-service date was accelerated.
- Cokesbury 100 kV Line (Coronaca–Hodges) project had an increase in estimated cost.
- South Point Switching Station project had an increase in estimated cost.
- Wateree 115 kV Plant, Upgrade 115/100 kV Transformers project had a decrease in estimated cost and its in-service date was pushed out.
- Carthage 230/115 kV Substation, Construct Sub project had an increase in estimated cost and its in-service date was accelerated.
- Falls 230 kV Sub, Add 300 MVAR SVC project had a decrease in estimated cost.

- Castle Hayne–Folkstone115 kV Line, Rebuild project had an increase in estimated cost and its in-service date was accelerated.

- Holly Ridge North 115 kV Switching Station, Construct project had a decrease in estimated cost and its in-service date was accelerated.

For a variety of reasons (such as load growth, generation retirements, or power purchase agreements expiring), LSEs may wish to evaluate other resource supply options to meet future load demand as part of the Local Economic Study Process. These resource supply options can be either in the form of transactions or some hypothetical generators which are added to meet the resource adequacy requirements for this study.

Also, each year as part of the Local Economic Planning Process, the Oversight Steering Committee ("OSC") will determine if there are any public policies driving the need for local transmission upgrades. Through this process the OSC will seek input from Transmission Advisory Group ("TAG") participants to identify any public policy impacts to be evaluated as part of the Local Planning Process. The OSC may itself identify public policies to be evaluated.

For the 2021 Local Planning Process Study, the NCUC Public Staff requested a public policy scenario involving several elements with potential impacts on the NC transmission system. As a result of this request, the NCTPC decided to evaluate the local public policy impacts of these various elements using the modelling assumptions involving the following five components:

1) Accelerated retirement of coal generation
    a. DEC will model the retirement of Allen 1-5, Cliffside 5, and Lee 3 and will model only the dual fuel capability of Marshall 1-4 and Belews Creek 1-2
    b. DEP will model the retirement of Roxboro 1-4, Mayo 1, Weatherspoon CTs, and Blewett CTs.
2) The increase of renewable generation within the Duke Energy Balancing Authority Areas (numbers below are nameplate output)
    a. DEC will model an additional 3000 MW of solar generation
    b. DEP will model an additional 1500 MW of solar generation and 568 MW of battery storage

3) Recent increase of solar and wind power plants located in Virginia and North Carolina within Dominion's service territory (PJM) to the extent locations are available
    a. Model 2460 MW of Dominion offshore wind into Fentress 500 kV Substation
    b. Dominion solar generation as represented in the current MMWG models
4) Addition of Midwest and Offshore wind generation (numbers below are nameplate output)
    a. DEC will model importing 1000 MW of offshore wind generation and 2500 MW of Midwest onshore wind and will export 1000 MW of that to DEP
    b. DEP will model an additional 1600 MW of offshore wind generation landing at New Bern 230 kV Substation and will export 1000 MW of that to DEC
5) DEP will model the addition of combined cycle gas generation at Roxboro Plant 230 kV Switchyard

To analyze the transmission system impact of the above components, the NCTPC will perform contingency analysis on the following two modeling cases:

Case 1

Load Level – Summer Peak Case

Maximize Onshore and offshore Wind 100% of nameplate

Scale Back Solar to 50% DEP and 80% DEC of nameplate, based on historical data

Mayo Battery 568MW generating

Economically dispatch other generation

Case 2

Load Level – 75% of Summer Peak Case

Maximize Onshore and offshore Wind 100% of nameplate

Maximize Solar 100% of nameplate

Mayo Battery 568MW charging

Economically dispatch other generation

The analysis of this public policy impact was not completed in time for inclusion in this report. Due to resource constraints within the study group, the public policy request study results have been delayed and will be provided in a supplemental report once the full analysis is completed in the first half of 2022.

In this 2021 NCTPC Process, the Participants validated and continued to build on the information learned from previous years' efforts. Each year the Participants will look for ways to improve and enhance the planning process. The study process confirmed again this year that the joint planning approach produces benefits for all Participants that would not have been realized without a collaborative effort.

II. North Carolina Transmission Planning Collaborative Process

II.A. Overview of the Process

The NCTPC Process was established by the Participants to:

1) provide the Participants (DEC, DEP, NCEMC, and ElectriCities) and other stakeholders an opportunity to participate in the electric transmission planning process for the areas of North Carolina and South Carolina served by the Participants;

2) preserve the integrity of the current reliability and least-cost planning processes;

3) expand the transmission planning process to include analysis of increasing transmission access to supply resources inside and outside the Balancing Authority Areas of DEC and DEP; and

4) develop a single coordinated transmission plan for the Participants that includes reliability and economic considerations while appropriately balancing costs, benefits, and risks associated with the use of transmission and generation resources.

The NCTPC Process is a coordinated Local Transmission Planning process conducted on an annual basis. The entire, iterative process ultimately results in a single Local Transmission Plan that appropriately balances the costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources. The Local Transmission Plan will identify local transmission projects (Local Projects). A Local Project is defined as a transmission facility that is (1) located solely within the combined DEC–DEP transmission system footprint and (2) not selected in the regional transmission plan for purposes of regional cost allocation.

The Local Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads. The overall Local Planning Process includes several components:

- Reliability Planning Process
- Resource Supply Options Process
- Local Economic Study Process
- Local Public Policy Process

The Reliability Planning Process (base reliability study) evaluates each Transmission System's ability to meet projected load with a defined set of resources as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations. The Resource Supply Options Process is conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements.

The overall Local Planning Process is designed such that there will be considerable feedback and iteration between the Reliability Planning Process and Resource Supply Options Process. This is necessary as the alternative solutions from one process affect the alternative solutions in the other process.

The Local Economic Study Process allows the TAG participants to propose economic upgrades to be studied as part of the Local Planning Process. This process evaluates the means to increase transmission access to potential supply resources inside and outside the Balancing Authority Areas of the DEC and DEP. This economic analysis provides the opportunity to study the transmission upgrades that would be required to reliably integrate new resources.

The Local Public Policy Process identifies if there are any public policies that are driving the need for local projects. Either the OSC or the TAG could identify those public policies that may drive the need for local transmission.

The OSC manages the NCTPC Process. The Planning Working Group ("PWG") implements the development of the NCTPC Process and coordinates the study development. The TAG provides advice and makes recommendations regarding the development of the NCTPC Process and the study results.

The final results of the Local Planning Process include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve customers. Throughout the Local Planning Process, TAG participants (including TAG participants representing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.

The purpose of the NCTPC Process is more fully described in the current Participation Agreement which is posted at http://www.nctpc.org/nctpc/.

II.B. Reliability Planning Process and Resource Supply Options Process

The Reliability Planning Process is the Transmission Planning Process that has traditionally been used by the transmission owners to provide safe and reliable transmission service at the lowest reasonable cost. Through the NCTPC, this Transmission Planning Process was expanded to include the active participation of the Participants and input from other stakeholders through the TAG.

The Reliability Planning Process is designed to follow the steps outlined below. The OSC approves the scope of the reliability study, oversees the study analysis being performed by the PWG, evaluates the study results, and approves the final reliability study results. The Reliability Planning Process begins with the incumbent transmission owners' most recent reliability planning studies and planned transmission upgrade projects.

In addition, the PWG solicits input from the Participants for different scenarios on where to include alternative supply resources to meet their load demand forecasts in the study. This is known as the Resource Supply Options Process. This step provides the opportunity for the Participants to propose the evaluation of other resource supply options to meet future load demand due to load growth, generation retirements, or the expiration of purchase power agreements. The PWG analyzes the proposed interchange transactions and/or the location of generators to determine if those transactions or generators create any reliability criteria violations. Based on this analysis, the PWG provides feedback to the Participants on the viability of the proposed interchange transactions or generator locations for meeting future load requirements. Note that new or modified interchange or generation must go through official FERC, NC, or SC Generator Interconnection or Transmission Service processes, which may find different results than the NCTPC study process. The PWG coordinates the development of the reliability study and the resource supply option study based upon the OSC approved scope and prepares a report with the recommended transmission reliability solutions.

The overall Local Planning Process is designed such that there will be considerable feedback and iteration between the Reliability Planning Process and the Resource Supply Options Process. This is necessary as the alternative solutions from one process may affect the alternative solutions in the other process.

The results of the Reliability Planning Process include summaries of the estimated costs and schedules to provide transmission upgrades and/or additions: (i) needed to maintain a sufficient level of reliability necessary to serve the native load of all Participants and (ii) needed to reliably support the resource supply options studied. The reliability study results are reviewed with the TAG, and the TAG participants are given an opportunity to provide comments on the results. All TAG feedback is reviewed by the OSC for consideration for incorporation into the final Collaborative Transmission Plan.

For the 2021 Study, the NCTPC evaluated no resource supply scenarios in the form of hypothetical transfers as it has done in prior years given the workload involved in doing the various scenarios of the Public Policy Requests received by the Public Staff. Resource supply scenarios will be solicited again for the 2022 Study and included if appropriate.

II.C. Local Economic Study Process

The Local Economic Study Process allows the TAG participants to propose hypothetical economic transfers to be studied as part of the Local Planning Process. The Local Economic Study Process provides the means to evaluate the impact of potential supply resources inside and outside the BAAs of the Transmission Providers. This local economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources.

The Local Economic Study Process begins with the TAG members proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces are compiled by the PWG and then evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle.

The OSC approves the scope of the local economic study scenarios (including any changes in the assumptions and study from those used in the reliability analysis), oversees the study analysis being coordinated by the PWG, evaluates the study results, and approves the final local economic study results.

The PWG coordinates the development of the local economic studies based upon the OSC approved scope and prepares a report which identifies recommended transmission solutions that could increase transmission access.

The results of the Local Economic Study Process include the estimated costs and schedules to provide the increased transmission capabilities.

The local economic study results are reviewed with the TAG, and the TAG participants are given an opportunity to provide comments on the results. All TAG feedback is reviewed by the OSC for consideration for incorporation into the final Local Transmission Plan.

While the overall NCTPC Process includes both a Reliability Planning Process and the Local Economic Study Process, some planning cycles may only focus on the Reliability Planning Process if stakeholders do not request any economic study scenarios for a particular planning cycle.

For the 2021 Study, the NCTPC evaluated no local economic scenarios as no local economic scenario requests were received by the Participants or Stakeholders by the deadline of January 18, 2021. Local economic scenarios will be solicited again for the 2022 Study and included if appropriate.

II.D. Local Public Policy Process

Each year, the OSC will determine if there are any public policies driving the need for local transmission upgrades. Through this process the OSC will seek input from TAG participants to identify any public policy impacts to be evaluated as part of the Local Planning Process. The OSC may itself identify public policies to be evaluated. The OSC will use the criteria below to determine if there are any public policies driving the need for local transmission as follows:

- The public policy must be reflected in state, federal, or local law or regulation (including order of a state, federal, or local agency).
- There must be existence of facts showing that the identified need cannot be met absent the construction of additional transmission facilities.

For the 2021 Local Planning Process Study, the NCUC Public Staff requested a public policy scenario involving several elements with potential impacts on the NC transmission system. As a result of this request, the

NCTPC decided to evaluate the local public policy impacts of these various elements using the modelling assumptions involving the following five components:

1) Accelerated retirement of coal generation
    a. DEC will model the retirement of Allen 1-5, Cliffside 5, and Lee 3 and will model only the dual fuel capability of Marshall 1-4 and Belews Creek 1-2
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    a. DEC will model an additional 3000 MW of solar generation
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    a. Model 2460 MW of Dominion offshore wind into Fentress 500 kV Substation
    b. Dominion solar generation as represented in the current MMWG models
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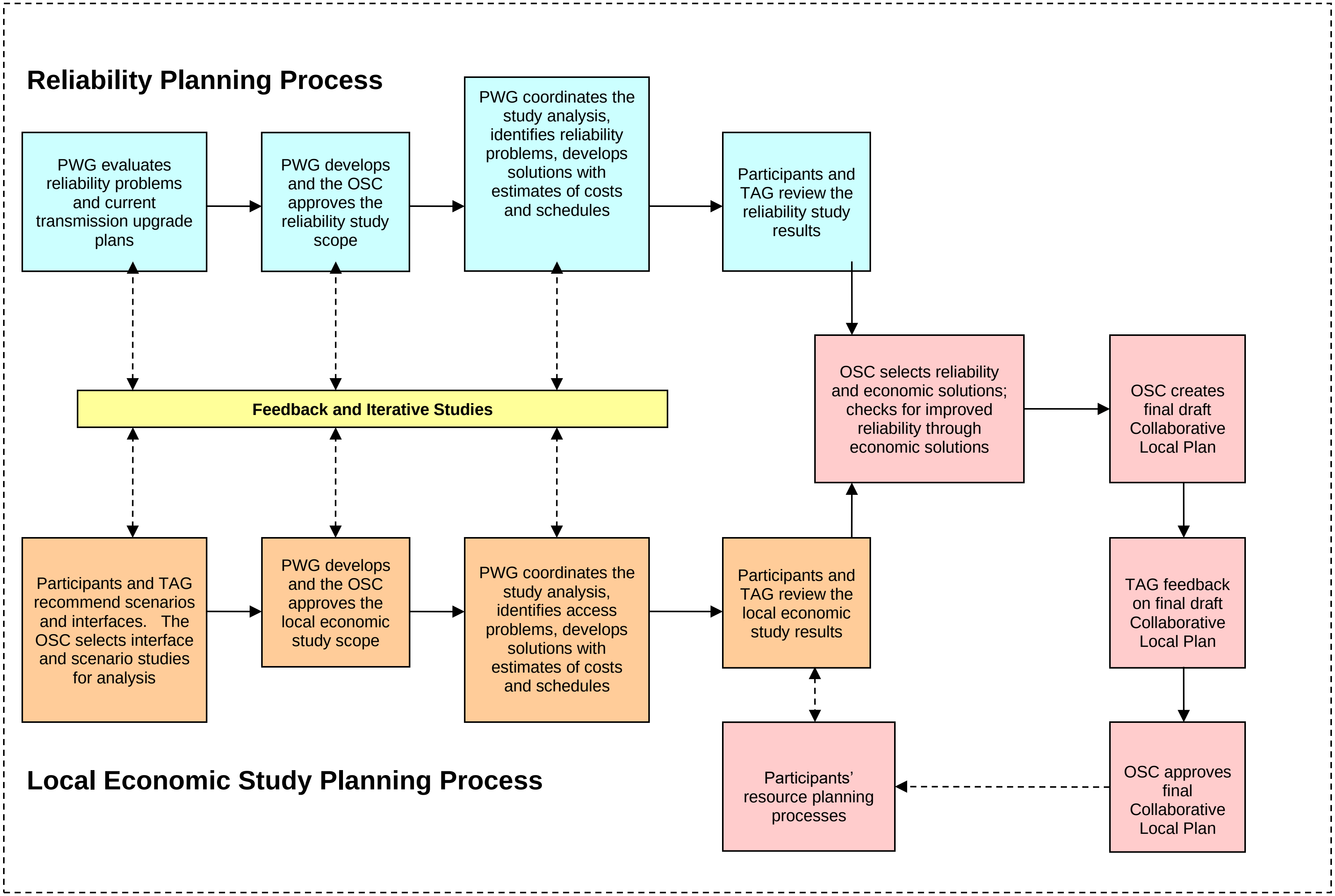
Maximize Onshore and offshore Wind 100% of nameplate
Scale Back Solar to 50% DEP and 80% DEC of nameplate, based on historical data
Mayo Battery 568MW generating
Economically dispatch other generation

Case 2
Load Level – 75% of Summer Peak Case
Maximize Onshore and offshore Wind 100% of nameplate
Maximize Solar 100% of nameplate
Mayo Battery 568MW charging
Economically dispatch other generation

The analysis of this public policy impact was not completed in time for inclusion in this report. Due to resource constraints within the study group, the public policy request study results have been delayed and will be provided in a supplemental report once the full analysis is completed in the first half of 2022.

2021 NCTPC Process Flow Chart



II.E. Local Transmission Plan

Once the reliability and local economic studies are completed, including any evaluations due to public policies, the OSC evaluates the results and the PWG recommendations to determine if any proposed economic projects and/or resource supply option projects will be incorporated into the Local Transmission Plan. If so, the initial plan developed based on the results of the reliability studies is modified accordingly. This process results in a single Local Transmission Plan being developed that appropriately balances the costs, benefits and risks associated with the use of transmission and generation resources. This plan is reviewed with the TAG, and the TAG participants are given an opportunity to provide comments. All TAG feedback is reviewed by the OSC for consideration for incorporation into the final Local Transmission Plan.

The annual Local Transmission Plan information is available to Participants for identification of any alternative least cost resources for potential inclusion in their respective Integrated Resource Plans. Other stakeholders can similarly use this information for their resource planning purposes.

III. 2021 Reliability Planning Study Scope and Methodology

The scope of the 2021 Reliability Planning Process was focused on the annual base reliability study. The base reliability study assessed the transmission systems of both DEC and DEP in order to ensure reliability of service in accordance with North American Electric Reliability Corporation (“NERC”), SERC Reliability Corporation (“SERC”), and DEC and DEP requirements. The purpose of the base reliability study was to evaluate the transmission systems’ ability to meet load growth projected for 2026 summer through 2031 summer with the Participants’ planned Designated Network Resources (“DNRs”). The 2021 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2021 Study also allowed for adjustments to existing plans where necessary.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2021 Plan addressed a ten-year planning horizon through 2031. The study years chosen for the 2021 Study are listed in Table 1.

Table 1

Study Years

Study Year / Season	Analysis
2026 Summer	Near-term base reliability
2026/2027 Winter	Near-term base reliability
2031 Summer	Long-term base reliability

To identify projects required in years other than the base study years of 2026, 2026/2027 and 2031, line loading results for those base study years were extrapolated into future years assuming the line loading growth rates in Table 2. This allowed assessment of transmission needs throughout the planning horizon. The line loading growth rates are based on each BAAs individual load growth projection at the time the study process was initiated.

Table 2
Line Loading Growth Rates

Company	Line Loading Growth Rate
DEC[1]	1.2% per year (summer) 1.2% per year (winter)
DEP	0.9% per year (summer) 0.9% per year (winter)

2. Network Modeling

The network models developed for the 2021 Study included new transmission facilities and upgrades for the 2026, 2026/2027, and 2031 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2020 Plan. Table 3 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2026, 2026/2027, and 2031 models. Table 4 lists the generation facility changes included in the 2026, 2026/2027, and 2031 models.

[1] For the purpose of planning a transmission system with appropriate robustness, DEC line loading growth rates shown in Table 2 exceed the growth rates provided in DEC's IRP.

Table 3

Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2026	2031
DEC	Windmere 100 kV Line (Dan River-Sadler), Construct	Yes	Yes
DEC	Wilkes 230/100 kV Tie Station, Construct	Yes	Yes
DEC	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	Yes	Yes
DEC	South Point Switching Station, Construct	Yes	Yes
DEC	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and add second circuit	Yes	Yes
DEC	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	No	Yes
DEC	Westport 230 kV Line (McGuire-Marshall), Upgrade	No	No
DEP	Sutton–Castle Hayne 115 kV North line rebuild	Yes	Yes
DEP	Asheboro–Asheboro East 115 kV North Line, Reconductor	Yes	Yes
DEP	Craggy–Enka 230 kV Line, Construct	Yes	Yes
DEP	Wateree 115 kV Plant, Upgrade 115/100 kV Transformers	Yes	Yes
DEP	Carthage 230/115 kV Substation, Construct Sub	Yes	Yes
DEP	Falls 230 kV Sub, Add 300 MVAR SVC	No	Yes
DEP	Castle Hayne–Folkstone 115 kV Line, Rebuild	No	Yes
DEP	Holly Ridge North 115 kV Switching Station, Construct	No	Yes

Table 4

Major Generation[2] Facility Changes in Models

Company	Generation Facility	2026	2031
DEC	Added Lincoln County CT (525 MW)	Yes	Yes
DEC	Retired Allen 1-5 (1083 MW)	Yes	Yes
DEC	Retired Cliffside 5 (574 MW)	Yes	Yes
DEC	Lee 3 (120 MW)	No	Yes
DEC	Added Apex PV (30 MW)	Yes	Yes
DEC	Added Blackburn PV (61.7 MW)	Yes	Yes
DEC	Added Broad River PV (50 MW)	Yes	Yes
DEC	Added Gaston PV (25 MW)	Yes	Yes
DEC	Added High Shoals PV (16 MW)	Yes	Yes
DEC	Added Lick Creek PV (50 MW)	Yes	Yes
DEC	Added Maiden Creek PV (69.3 MW)	Yes	Yes
DEC	Added Oakboro PV (40 MW)	Yes	Yes
DEC	Added Olin Creek PV (35 MW)	Yes	Yes
DEC	Added Partin PV (50 MW)	Yes	Yes
DEC	Added Pelham PV (32 MW)	Yes	Yes
DEC	Added Pinson PV (20 MW)	Yes	Yes
DEC	Added Ruff PV (22 MW)	Yes	Yes
DEC	Added Speedway PV (22.6 MW)	Yes	Yes
DEC	Added Stanly PV (50 MW)	Yes	Yes
DEC	Added Stony Knoll PV (22.6 MW)	Yes	Yes
DEC	Added Sugar PV (60 MW)	Yes	Yes
DEC	Added Thinking Tree (35 MW)	Yes	Yes
DEC	Added Two Hearted PV (22 MW)	Yes	Yes

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

Company	Generation Facility	2026	2031
DEC	Added West River PV (40 MW)	Yes	Yes
DEC	Added Westminster PV (75 MW)	Yes	Yes
DEP	Retired Darlington Co 1, 2, 3, 4, 6, 7, 8, 10 (514 MW)	Yes	Yes
DEP	Retired Blewett CTs 1-4 and Weatherspoon CTs 1-4 (232 MW)	Yes	Yes
DEP	Retired Roxboro Units 1-2 (1053 MW)	No	Yes
DEP	Retired Mayo Unit 1 (746 MW)	No	Yes
DEP	Added Highest Power Solar (48.7 MW)	Yes	Yes
DEP	Added Trent River Solar (79.9 MW)	Yes	Yes
DEP	Added Bay Tree Solar (70.1 MW)	Yes	Yes
DEP	Added Roxboro CC Units 1-2 (2700 MW)	No	Yes
DEP	Added Mayo Battery Storage (568 MW)	No	Yes

3. Interchange and Generation Dispatch

Each Participant provided a resource dispatch order for each of its DNRs for the DEC and DEP BAAs. Generation was dispatched for each Participant to meet that Participant's load in accordance with the designated dispatch order.

DEC models distribution-connected generation as being netted against the load at the transmission bus. Transmission-connected generation is modeled if it is either in-service or has an executed generator interconnection agreement at the time the models are built. Because only transmission-connected generation is modeled explicitly, the following assumptions do not apply to distribution-connected generation. Solar generation is available for dispatch up to the generator interconnection agreement value but is only dispatched at 80% of that value in summer models. Facilities with storage may be dispatched up to 100% of the generator interconnection agreement value depending on the amount of storage associated with the facility. This level of dispatch is jurisdiction-specific and is supported by operating data that can be reflective of various factors such as geography and plant design. Solar generation is not dispatched in winter models. These dispatch assumptions reflect the expected solar generation output coincident with the DEC peak load. DEC models 1103 MW of transmission-connected solar generation available for dispatch, dispatched consistent with the aforementioned dispatch assumptions.

DEP models' solar generation in its power flow cases that is either in-service or has an executed generator interconnection agreement at the time the models are built. This includes transmission-connected as well as distribution-connected solar generation. The current 2026 summer power flow case has approximately 1504 MW of transmission-connected and 1927 MW of distribution-connected solar generation for a total of 3431 MW. In its summer peak cases, DEP scales the solar generation down to 50% of its maximum capacity to approximate the amount of solar generation that will be on-line coincident with the DEP peak load. This level of dispatch is jurisdiction-specific and is supported by operating data that can be reflective of various factors such as geography and plant design. For winter peak studies, DEP assumes that no solar generation will be available at the time of the winter peak. DEP models all transmission upgrades that are determined necessary by the respective generation interconnection studies.

III.B. Study Criteria

The results of the base reliability study, the resource supply option study, and the local economic study were evaluated using established planning criteria. The planning criteria used to evaluate the results include:

1) NERC Reliability Standards;
2) SERC requirements; and
3) Individual company criteria.

III.C. Case Development

The base case for the base reliability study was developed using the most current 2020 series NERC Multiregional Modeling Working Group ('MMWG") model for the systems external to DEC and DEP. The MMWG model of the external systems, in accordance with NERC MMWG criteria, included modeling known long-term firm transmission reservations. Detailed internal models of the DEC and DEP East/West systems were merged into the base case, including DEC and DEP transmission additions planned to be in service by the period under study. In the base cases, all confirmed long-term firm transmission reservations with roll-over rights were modeled.

III.D. Transmission Reliability Margin

NERC defines Transmission Reliability Margin as:

> *The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.*

DEP's reliability planning studies model all confirmed transmission obligations for its BAA in its base case. Included in this is TRM for use by all LSEs. TRM is composed of contracted VACAR reserve sharing and inrush impacts. DEP models TRM by scheduling the reserved amount on actual reserved interfaces as posted on the DEP Open Access Same-time Information System ("OASIS").

In the planning horizon, DEC ensures VACAR reserve sharing requirements can be met through decrementing Total Transfer Capability ("TTC") by the TRM value required on each interface. Sufficient TRM is maintained on all DEC-VACAR interfaces to allow both export and import of the required VACAR reserves. DEC posts the TRM value for each interface on the DEC OASIS.

Both DEP and DEC ensure that TRM is maintained consistent with NERC requirements. The major difference between the methodologies used in planning by the two companies to calculate TRM is that DEP uses a flow-based methodology, while DEC decrements previously calculated TTC values on each interface.

III.E. Technical Analysis and Study Results

Contingency screenings on the base case and scenarios were performed using Power System Simulator for Engineering ("PSS/E") power flow or equivalent. Each transmission planner simulated its own transmission and generation down contingencies on its own transmission system.

DEC created generator maintenance cases that assume a major unit is removed from service and the system is economically redispatched to make up for the loss of generation. Additionally, outages of transmission connected solar sites were evaluated by creating cases that reflected one of two assumptions: 1) individual solar site being unavailable or 2) a group of solar sites being unavailable. For the latter, engineering judgement was used to group sites in common geographic areas.

Generator maintenance cases were developed for the following units:

Bad Creek 1	Belews Creek 1	Catawba 1
Cliffside 6	Broad River 1	Mill Creek 1
Jocassee 1	Lee 3	Marshall 3
McGuire 1	McGuire 2	Nantahala
Oconee 1	Oconee 3	Buck CC
Dan River CC	Rowan CC	Rockingham 1
Thorpe	Lincoln 1	Lee CC
Broad River 1	Cleveland 1	Cherokee Co-gen

DEP created generation down cases which included the use of TRM, as discussed in Section III.D. DEP TRM cases model interchange to avoid netting against imports, thereby creating a worst-case import scenario. TRM cases were developed for the following units:

Brunswick 1	Robinson 2
Harris	Asheville CC1

To understand impacts on each other's system, DEC and DEP have exchanged their transmission contingency and monitored elements files in order for each company to simulate the impact of the other company's contingencies on its own transmission system. In addition, each company coordinated generation adjustments to accurately reflect the impact of each company's generation patterns.

The technical analysis was performed in accordance with the study methodology. The results from the technical analysis for the DEC and DEP systems were shared with all Participants. Solutions of known issues within DEC and DEP were discussed. New or emerging issues identified in the 2021 Study were also discussed with all Participants so that all are aware of potential issues. Appropriate solutions were developed and tested.

The results of the technical analysis were discussed throughout the study area based on thermal loadings greater than 90% for base reliability, and greater than 80% for resource supply options and local economic studies to allow evaluation of project acceleration.

III.F. Assessment and Problem Identification

DEC and DEP performed an assessment in accordance with the methodology and criteria discussed earlier in this section of this report, with the analysis work shared by DEC and DEP. The reliability issues identified from the assessments of both the base reliability cases and the local economic study scenarios were documented and shared within the PWG. These results will be reviewed and discussed with the stakeholder group for feedback.

III.G. Solution Development

The 2021 Study performed by the PWG confirmed base reliability problems already identified (i) by DEC and DEP in company-specific planning studies performed individually by the transmission owners and (ii) by the 2020 Study. The PWG participated in the review of potential solution alternatives to the identified base reliability problems and to the issues identified in the resource supply option analysis. The solution alternatives were simulated using the same assumptions and criteria described in Sections III.A through III.E. DEC and DEP developed planning cost estimates and construction schedules for the solution alternatives.

III.H. Selection of Preferred Reliability Solutions

For the base reliability study, the PWG compared solution alternatives and selected the preferred solution, balancing cost, benefit and risk. The PWG selected a preferred set of transmission improvements that provide a reliable and cost-effective transmission solution to meet customers' needs while prudently managing the associated risks.

III.I. Contrast NCTPC Report to Other Regional Transfer Assessments

For both the DEC and DEP BAAs, the results of the PWG study are consistent with SERC Long-Term Working Group ("LTWG") studies performed for similar timeframes. LTWG studies have recently been performed for the 2026 summer timeframe. The limiting facilities identified in the PWG study of base reliability have been previously identified in the LTWG studies for similar scenarios. These limiting facilities have also been identified in the individual transmission owner's internal assessments required by NERC reliability standards.

IV. Base Reliability Study Results

The 2021 Study verified that DEC and DEP have projects already planned to address reliability concerns for the near-term (5 year) and long-term (10 year) planning horizons. There were no unforeseen problems identified in the reliability studies performed on the base cases.

The 2021 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million. Projects in the 2021 Plan are those projects identified in the base reliability study. For each of these projects, Appendix B provides the project status, the estimated cost, the planned in-service date, and the estimated time to complete the project.

The total estimated cost for the 16 reliability projects included in the 2021 Plan is $694 million as documented in Appendix B. This compares to the original 2020 Plan estimate of $804 million for 17 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. An update to the 2020 plan was provided in the 2021 mid-year update published in June 2021 with an updated cost estimate of $846 million. See Appendix D for a detailed comparison of this year's Plan to the updated 2020 Plan.

V. Local Public Policy Study Results

The analysis of this public policy impact was not completed in time for inclusion in this report. The study results will be provided in a separate report once the full analysis is completed in 2022.

VI. Collaborative Transmission Plan

The 2021 Plan includes 16 reliability projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. The total estimated cost for these 16 reliability projects in the 2021 Plan is $694 million. This compares to the original 2020 Plan estimate of $804 million for 17 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. An update to the 2020 plan was provided in the 2021 mid-year update published in June 2021 with an updated cost estimate of $846 million. See Appendix D for a detailed comparison of this year's Plan to the updated 2020 Plan. The list of major projects will continue to be modified on an ongoing basis as new improvements are identified through the NCTPC Process and projects are in-service or eliminated from the list. Appendix C provides a more detailed description of each project in the 2021 Plan and includes the following information:

1) Reliability Projects: Description of the project.

2) Issue Resolved: Specific driver for project.

3) Status: Status of development of the project as described below:

    a. In-Service – Projects with this status are in-service.
    b. Underway – Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.
    c. Planned – Projects with this status do not have money in the Transmission Owner's current year budget and the project is subject to change.
    d. Conceptual – Projects with this status are not Planned at this time but will continue to be evaluated as a potential project in the future.
    e. Deferred – Projects with this status were identified in the 2020 Report and have been deferred beyond the end of the planning horizon based on the 2021 Study results.

f. Removed - Project is cancelled and no longer in the plan.

4) Transmission Owner: Responsible equipment owner designated to design and implement the project.

5) Projected In-Service Date: The date the project is expected to be placed in service.

6) Estimated Cost: The estimated cost, in nominal dollars, which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

7) Project lead time: Number of years needed to complete project. For projects with the status of Underway, the project lead time is the time remaining to complete construction of the project and place the project in service.

Appendix A
Interchange Tables

2026 SUMMER PEAK, 2026/2027 WINTER PEAK, 2031 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE (BASE)

Duke Energy Carolinas Modeled Imports – MW

	26S	26/27W	31S
CPLE (NCEMC–Hamlet)	165	165	165
PJM (DVP/PJM)	2	2	2
SCEG (Chappells)	2	2	2
SCPSA (PMPA)	210	96	227
SCPSA (Seneca)	31	28	32
SEPA (Hartwell)	181	181	181
SEPA (Thurmond)	113	113	113
SOCO (NCEMC)	44	44	44
Total	**748**	**631**	**766**

Duke Energy Carolinas Modeled Exports – MW

	26S	26/27W	31S
CPLE (Broad River)	875	875	875
CPLE (Cleveland)	195	195	195
CPLE (KMEC)	27	87	87
CPLE (NCEMC–Catawba)	307	307	307
CPLE (CPLC)	190	190	190
PJM (NCEMC–Catawba)	100	100	100
SCEG (KMEC)	5	5	5
SCPSA (Haile)	15	15	15
Total	**1714**	**1774**	**1774**

Duke Energy Carolinas Net Interchange – MW

	26S	26/27W	31S
	966	**1143**	**1008**

Note: Positive net interchange indicates an export and negative interchange an import.

2026 SUMMER PEAK, 2026/2027 WINTER PEAK, 2031 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (East) Modeled Imports – MW

	26S	26/27W	31S
PJM (NCEMC–AEP)	100	100	100
PJM (NCEMC)	75	75	75
DUK (Broad River)	875	875	875
DUK (Cleveland)	195	195	195
DUK (NCEMC–Catawba)	307	307	307
DUK (KMEC)	27	87	87
DUK (CPLC)	190	190	190
PJM (SEPA–KERR)	95	95	95
Total	**1864**	**1924**	**1924**

Duke Energy Progress (East) Modeled Exports – MW

	26S	26/27W	31S
CPLW (Transfer)	0	150	0
PJM (NCEMC–Hamlet)	165	165	165
DUK (NCEMC–Hamlet)	165	165	165
Total	**330**	**480**	**330**

Duke Energy Progress (East) Net Interchange – MW

	26S	26/27W	31S
	-1534	**-1444**	**-1594**

Note: Positive net interchange indicates an export and negative interchange an import.

2026 SUMMER PEAK, 2026/2027 WINTER PEAK, 2031 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (West) Modeled Imports – MW

	26S	26/27W	31S
CPLE (Transfer)	0	150	0
SCPSA (Waynesville)	22	22	22
TVA (SEPA)	14	14	14
Total	**36**	**186**	**36**

Duke Energy Progress (West) Modeled Exports – MW

	26S	26/27W	31S
–--	---	---	---
Total	**---**	**---**	**---**

Duke Energy Progress (West) Net Interchange – MW

	26S	26/27W	31S
	-36	**-186**	**-36**

Note: Positive net interchange indicates an export and negative interchange an import.

2026 SUMMER PEAK, 2026/2027 WINTER PEAK, 2031 SUMMER PEAK DUKE ENERGY DUKE ENERGY PROGRESS (WEST), DUKE ENERGY PROGRESS (EAST) DETAILED INTERCHANGE (TRM)

Duke Energy Progress (West) Modeled Imports – MW

	26S, 26/27W, 31S
AEP (TRM)	69
DUK (TRM)	191
TVA (TRM)	20
Total	**280**

Duke Energy Progress (East) Modeled Imports – MW

	26S, 26/27W, 31S
AEP (TRM)	100
DUK (TRM)	773
DVP (TRM)	427
SCEG (TRM)	200
SCPSA (TRM)	326
Total	**1826**

Note: Imports and exports for TRM are in addition to Base transfers

Appendix B
Transmission Plan
Major Project
Listings –
Reliability Projects

2021 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0024	Durham–RTP 230 kV Line, Reconductor	Conceptual	DEP	TBD	20	4
0034	Sutton–Castle Hayne 115 kV North Line, Rebuild	In-service	DEP	6/1/2021	30	-
0039	Asheboro–Asheboro East 115 kV North Line, Reconductor	Underway	DEP	6/1/2022	12	0.5
0046	Windmere 100 kV Line (Dan River-Sadler), Construct	Underway	DEC	12/1/2023	28	2
0048	Wilkes 230/100 kV Tie Station, Construct	Underway	DEC	6/1/2024	69	2.5

2021 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0050	Craggy–Enka 230 kV Line, Construct	Planned	DEP	12/1/2025	74	4
0051	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	Planned	DEC	12/1/2024	20	3
0052	South Point Switching Station, Construct	Underway	DEC	12/1/2024	111	3
0053	Wateree 115 kV Plant, Upgrade 115/100 kV Transformers	Underway	DEP	12/1/2023	10	2
0054	Carthage 230/115 kV Substation, Construct Sub	Conceptual	DEP	12/1/2025	27	4

2021 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0055	Falls 230 kV Sub, Add 300 MVAR SVC	Conceptual	DEP	12/1/2028	45	4
0056	Castle Hayne–Folkstone115 kV Line, Rebuild	Planned	DEP	12/1/2026	85	4
0057	Holly Ridge North 115 kV Switching Station, Construct	Conceptual	DEP	12/1/2026	20	4
0058	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Add Second Circuit	Planned	DEC	12/1/2025	15	3.5
0059	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	Planned	DEC	6/1/2027	88	5

1

2021 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0060	Westport 230 kV Line (McGuire-Marshall), Upgrade	Conceptual	DEC	TBD	40	5
TOTAL					**694**	

Status: ***In-service***: Projects with this status are in-service. This status was updated as of 12/1/2021.

Underway: Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.

Planned: Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

Conceptual: Projects with this status are not p*lanned* at this time but will continue to be evaluated as a potential project in the future.

Deferred: Projects with this status were identified in the 2020 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2021 Collaborative Transmission Plan.

Removed: Project is cancelled and no longer in the plan

[2] The estimated cost is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

[3] For projects with a status of Underway, the project lead time is the time remaining to complete construction and place in-service.

Appendix C
Transmission Plan Major Project Descriptions – **Reliability Projects**

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Note: The estimated cost for each of the projects described in Appendix C is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

Project ID and Name: 0024 – Durham–RTP 230 kV Line, Reconductor

Project Description
Reconductor approximately 10 miles of 230 kV line with 6–1590 ACSR conductor.

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	TBD
Estimated Time to Complete	4 years
Estimated Cost	$20 M

Narrative Description of the Need for this Project
With Harris Plant down, a common tower outage of the Method (DEC)–East Durham and the Durham–Method 230 kV Lines will cause an overload of the Durham 500 kV Sub-RTP 230 kV Switching Station Line.

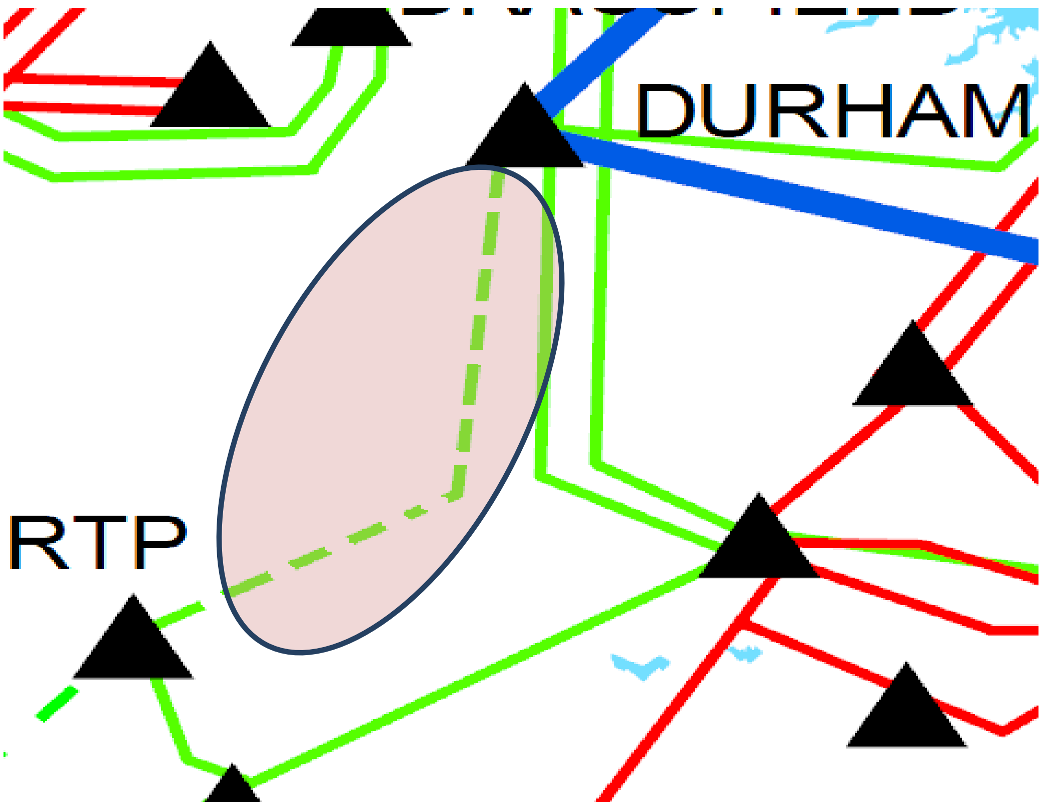
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV subs.

Why this Project was Selected as the Preferred Solution
Cost and feasibility. Reconductoring is much more cost effective.

C–1

Durham–RTP 230 kV Line

- **NERC Category P3 Violation**
- **Problem:** With Harris Plant down, a common tower outage of the Method (DEC)–East Durham and the Durham–Method 230 kV Lines will cause an overload of the Durham 500 kV Sub-RTP 230 kV Switching Station Line.
- **Solution:** Reconductor approximately 10 miles of 230 kV line with 6-1590 ACSR conductor.



Project ID and Name: 0034 – Sutton–Castle Hayne 115 kV North Line, Rebuild

Project Description
This project consists of rebuilding the Sutton Plant – Castle Hayne 115 kV North Line using 1272 MCM ACSR conductor or equivalent (approximately 8 miles). The line traps at both Sutton and Castle Hayne terminals will be removed in conjunction with the installation of OPGW. The 800 A current transformers at both line terminals will have to be uprated as part of this project.

Status	In-service
Transmission Owner	DEP
Planned In-Service Date	6/1/2021
Estimated Time to Complete	Completed
Estimated Cost	$30 M

Narrative Description of the Need for this Project
By 2021, with all area generation online, the loss of the Sutton Plant–Castle Hayne 115 kV South Line will cause the Sutton Plant–Castle Hayne 115 kV North Line to exceed its thermal rating.

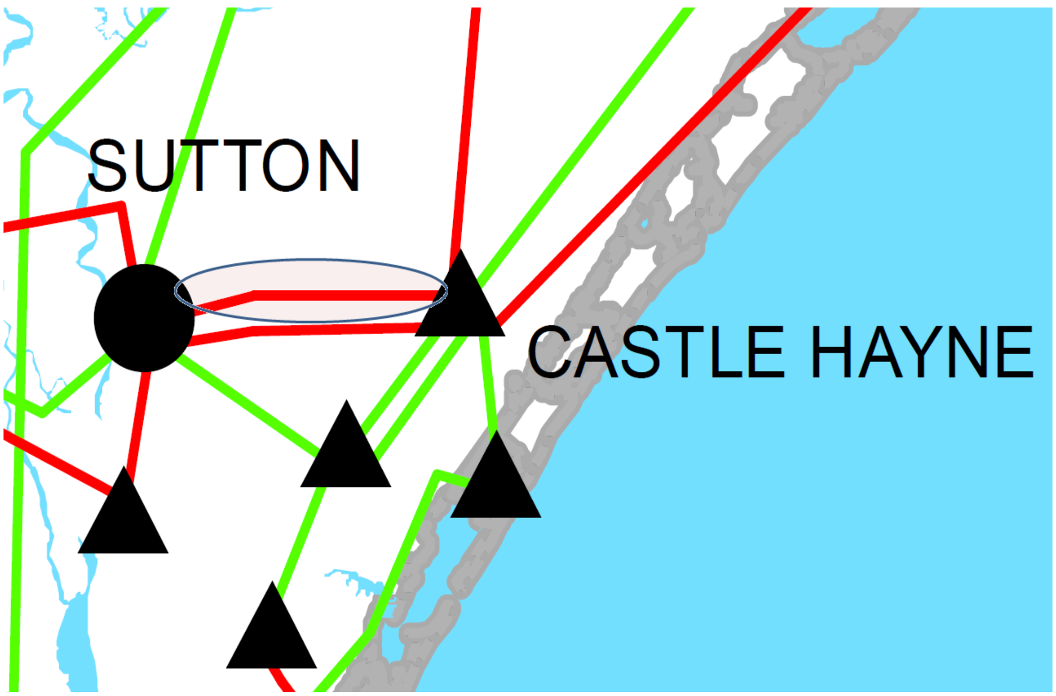
Other Transmission Solutions Considered
Convert 115 kV line to 230 kV.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

C–2

Sutton–Castle Hayne 115 kV North Line, Rebuild

- **NERC Category P1 violation**
- **Problem:** By 2021, with all area generation online, the loss of the Sutton Plant–Castle Hayne 115 kV South Line will cause the Sutton Plant–Castle Hayne 115 kV North Line to exceed its thermal rating.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0039 – Asheboro–Asheboro East 115 kV North Line, Reconductor

Project Description
This project consists of rebuilding/reconductoring approximately 6.5 miles of the existing 115 kV line using 3-1590 or equivalent conductor. This project requires the replacement of disconnect switches at Asheboro 230 kV and the replacement of the breaker, the disconnect switches, and the 115 kV east bus at Asheboro East 115 kV associated with this line. Both ends of the line will also require CT/metering equipment upgrades such that they are not the limit to the line rating. The upgraded equipment for this line should be 2000 amp minimum.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2022
Estimated Time to Complete	0.5 years
Estimated Cost	$12 M

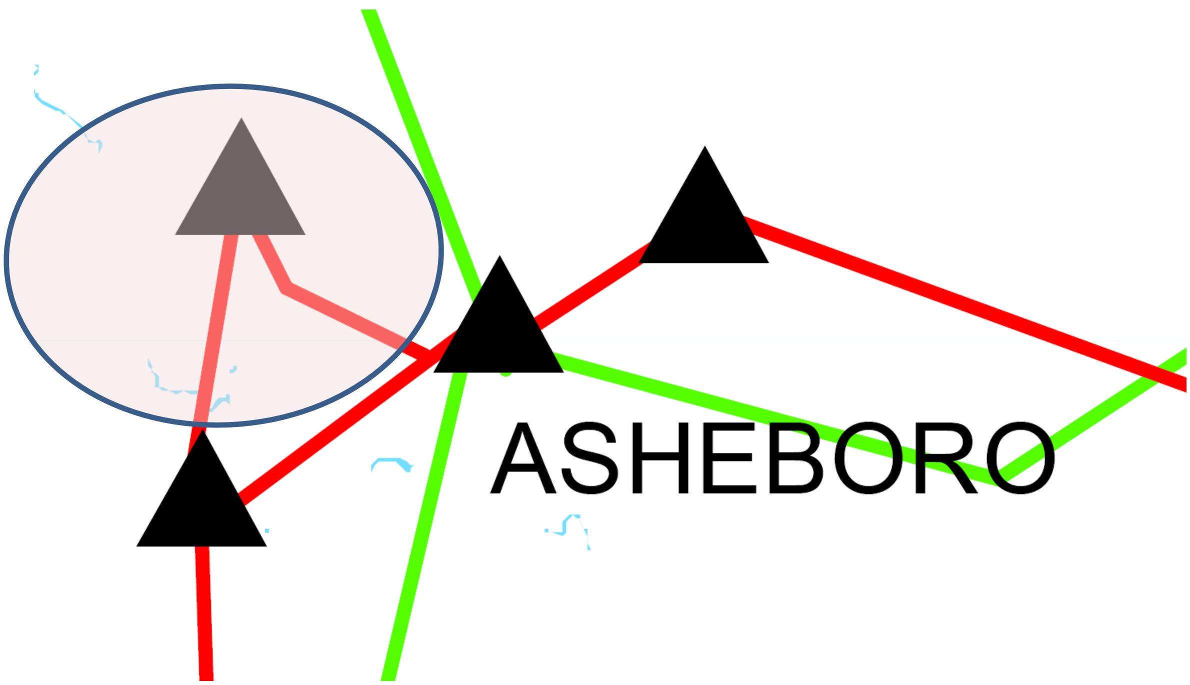
Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Asheboro–Asheboro East 115 kV North line under the contingency of losing the Asheboro–Asheboro East 115 kV South line with Harris Plant down.

Other Transmission Solutions Considered
Construct a new 115 kV line from Asheboro to Asheboro East.

Why this Project was Selected as the Preferred Solution
Cost and feasibility.

Asheboro–Asheboro East 115 kV North Line, Reconductor

- **NERC Category P3 violation**
- **Problem:** By the summer of 2022, with Harris down, the loss of the Asheboro–Asheboro East 115 kV South line will cause the Asheboro–Asheboro East 115 kV North line to overload.
- **Solution:** Rebuild/reconductor the Asheboro–Asheboro East 115 kV North Line and upgrade equipment.



Project ID and Name: 0046 – Windmere 100 kV Line (Dan River–Sadler), Construct

Project Description
This project consists of building a new 100 kV line (954 AAC) along an existing ROW.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2023
Estimated Time to Complete	2 years
Estimated Cost	$28 M

Narrative Description of the Need for this Project
The Reidsville and Wolf Creek 100 kV lines (Dan River–Sadler) can become overloaded for the loss of any of the circuits between Dan River and Sadler.

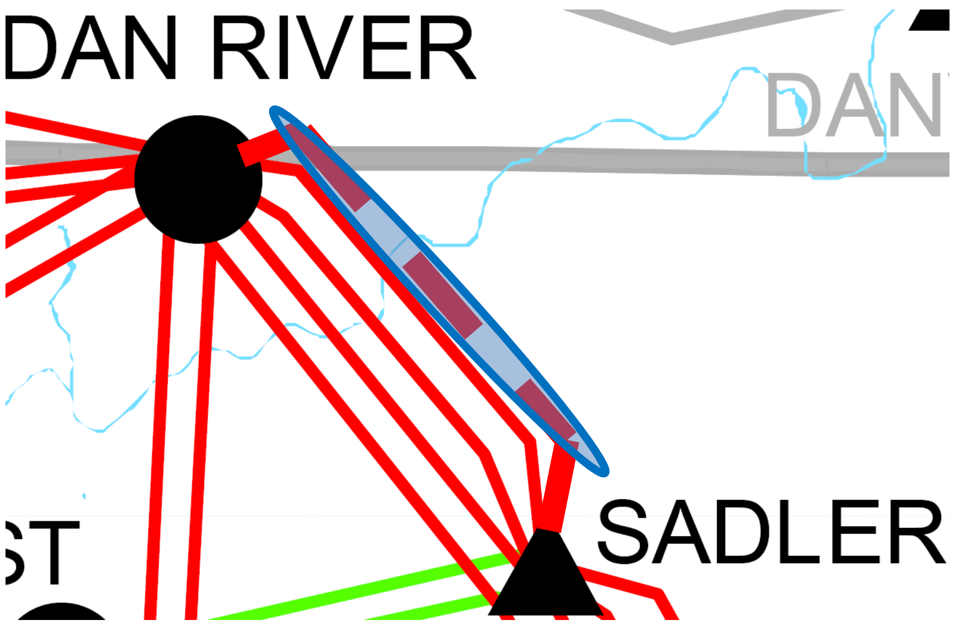
Other Transmission Solutions Considered
Rebuilding both double circuit 100 kV lines (≈8 miles each) between Dan River and Sadler.

Why this Project was Selected as the Preferred Solution
Greater operational flexibility in the area.

C–4

Windmere 100 kV Line (Dan River–Sadler), Construct

- **NERC Category P3 violation**
- **Problem:** Loss of any of the four existing 100 kV circuits between Dan River and Sadler and can overload the remaining circuits.
- **Solution:** Construct new 100 kV line.



Project ID and Name: 0048 – Wilkes 230/100 kV Tie Station, Construct

Project Description
This project consists of building a new 230/100 kV Wilkes tie station and re-routing local transmission lines.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	6/1/24
Estimated Time to Complete	2.5 years
Estimated Cost	$69 M

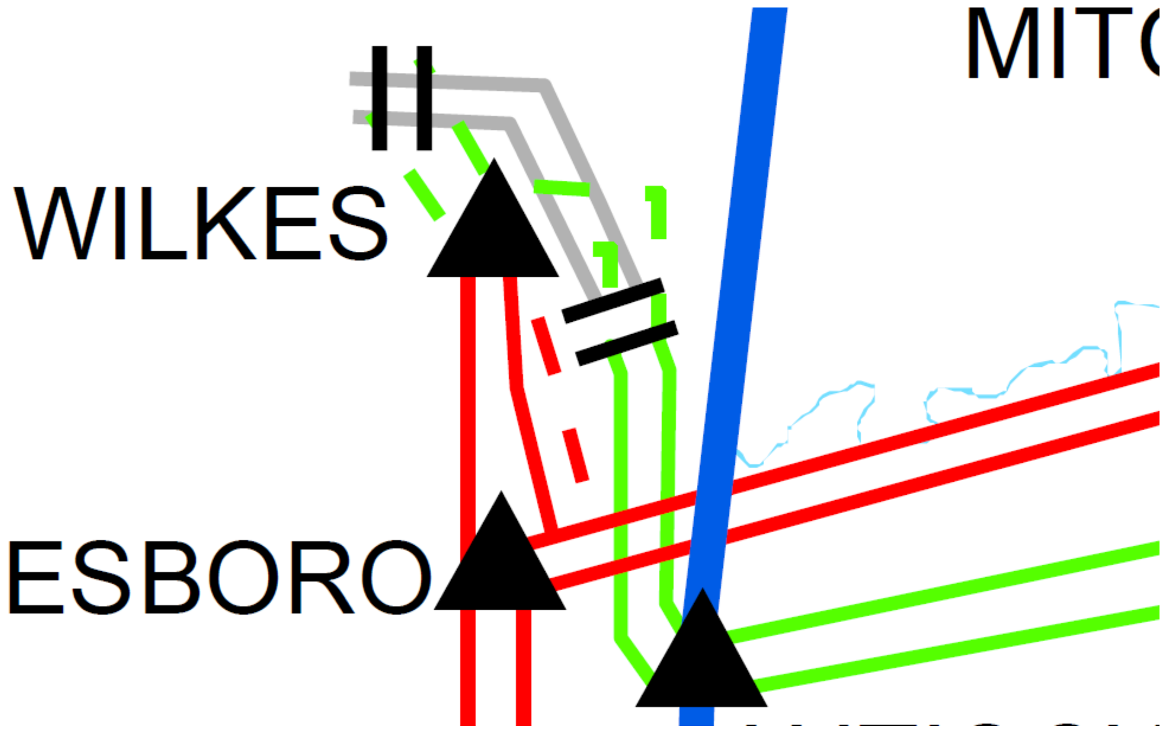
Narrative Description of the Need for this Project
The primary driver for this project is to increase support in the area around Wilkesboro NC. Contingencies, especially in the winter, have the tendency to drop voltage in the area as well as some thermal loading concerns with the loss of the Oxford 100 kV line. The secondary driver is to alleviate the need to rebuild N Wilkesboro Tie as a result of the need to install a bus junction breaker at N Wilkesboro Tie. Presently, loss of the single N Wilkesboro bus takes out six 100 kV lines, causes loss of load and low voltage problems in the area. Installation of a bus junction breaker would also cause thermal loading issues requiring a line upgrade. This project also makes use of 230 kV transmission lines that pass adjacent to the new 230/100 kV tie station.

Other Transmission Solutions Considered
Rebuild N Wilkesboro Tie to allow installation of a bus tie breaker.

Why this Project was Selected as the Preferred Solution
Greater long-term value to system and operational flexibility in the area.

Wilkes 230/100 kV Tie Station, Construct

- **NERC Category P1, P2, & P3 violation**
- **Problem:** Contingency events in the Wilkesboro, NC area cause thermal loading issues, loss of load and low voltage problems in the area.
- **Solution:** Construct new 230/100 kV tie station.



Project ID and Name: 0050 – Craggy-Enka 230 kV Line, Construct

Project Description
This project consists of constructing approximately 10 miles of new 230 kV transmission line between the Craggy and Enka Substations.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2025
Estimated Time to Complete	4 years
Estimated Cost	$74 M

Narrative Description of the Need for this Project
Opening the Asheville end of the Oteen 115 kV West line overloads the Enka – West Asheville 115 kV line. Also, a NERC P6 outage of Craggy–Enka 115 and Asheville–Oteen 115 West lines has no viable operating procedure beginning 12/1/2025. Outage of the West Asheville 115 kV bus overloads the Craggy–Enka 115 kV line.

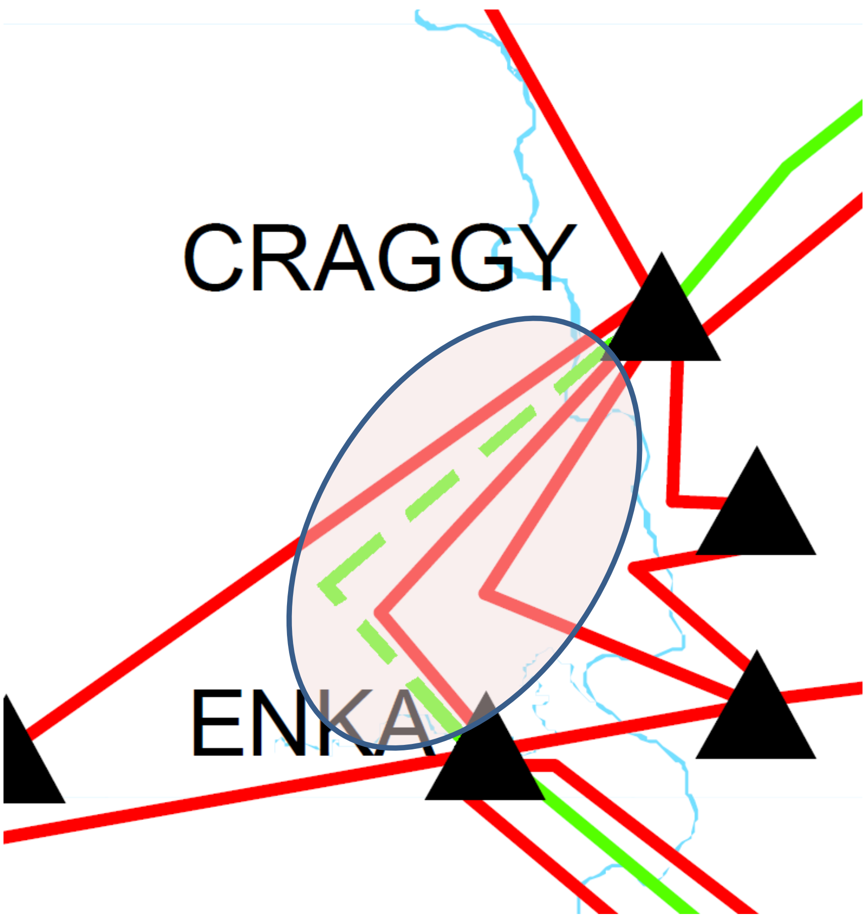
Other Transmission Solutions Considered
Reconductoring multiple transmission lines. These include the Enka–West Asheville 115 kV Line, the Craggy–Enka 115 kV line, the Canton–Craggy 115 kV Line, and the Asheville–Oteen 115 kV East Line.

Why this Project was Selected as the Preferred Solution
Cost and feasibility.

C–6

Craggy–Enka 230 kV Line, Construct

- **NERC Category P3 & P6 violation**
- **Problem:** Opening the Asheville end of the Oteen 115 kV West line overloads the Enka – West Asheville 115 kV line. Also, a NERC P6 outage of Craggy–Enka 115 kV and Asheville–Oteen 115 kV West lines has no viable operating procedure beginning 12-2025. Outage of the West Asheville 115 kV bus overloads the Craggy–Enka 115 kV line.
- **Solution:** Construct the Craggy–Enka 230 kV Line.



Project ID and Name: 0051 – Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade

Project Description
This project consists of rebuilding 9.2 miles of the existing 477 ACSR conductor with 1272 ACSR.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/24
Estimated Time to Complete	3 years
Estimated Cost	$20 M

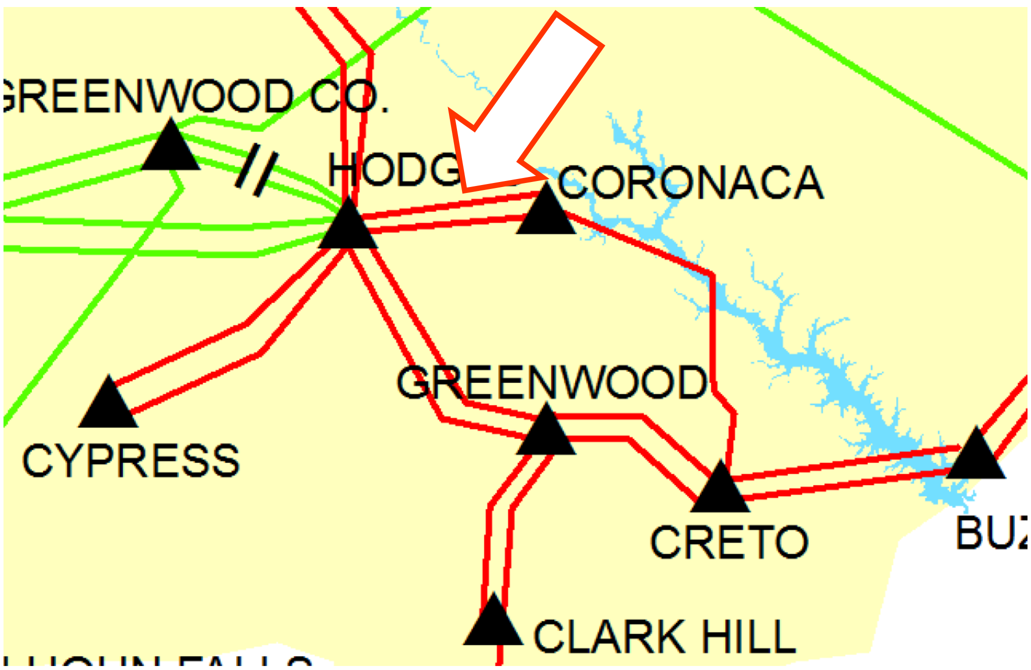
Narrative Description of the Need for this Project
These lines may become overloaded for loss of one of the circuits.

Other Transmission Solutions Considered
New transmission line(s).

Why this Project was Selected as the Preferred Solution
New transmission line(s) would require additional right-of-way, adding to the cost of the project.

Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade

- **NERC Category P3 violation**
- **Problem:** Loss of one of the Greenwood–Hodges 100 kV lines may overload the remaining line.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



Project ID and Name: 0052 – South Point Switching Station, Construct

Project Description
This project consists of replacing (in a new location) the switchyard at Allen Steam Station and upgrading the existing 230/100 kV transformers.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/24
Estimated Time to Complete	3 years
Estimated Cost	$111 M

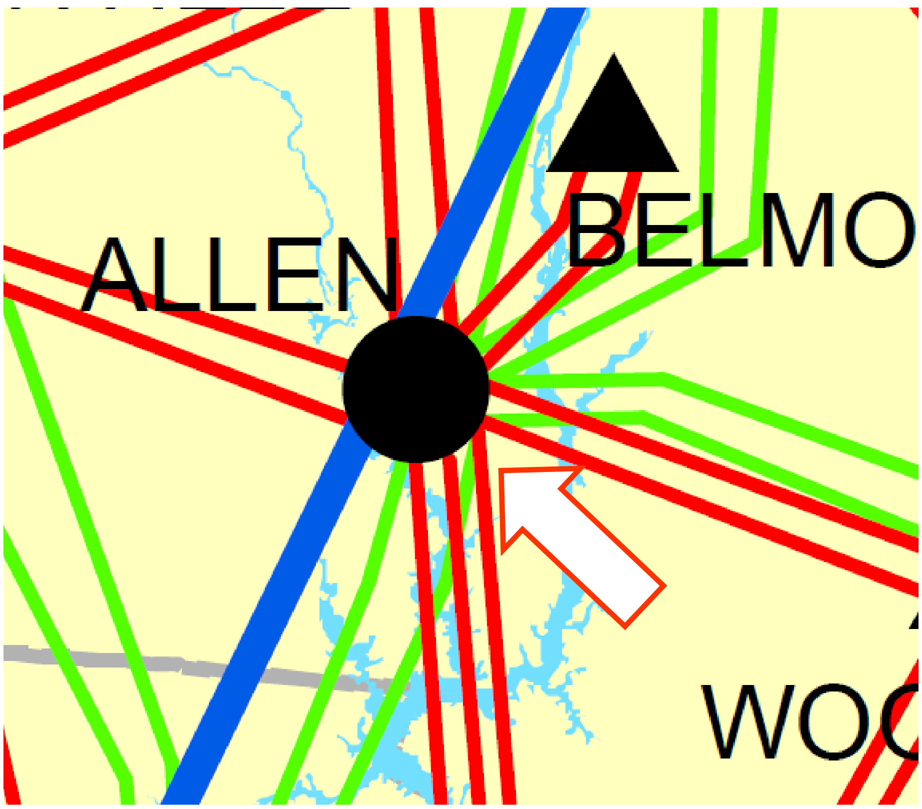
Narrative Description of the Need for this Project
The transformers may become overloaded for loss of the other transformer, and there are obsolescence issues with the existing switchyard at Allen Steam Station.

Other Transmission Solutions Considered
Convert Wylie Switching Station to 230/100 kV. Rebuild Allen Steam Station in its current location, and replace existing 230/100 kV transformers at Allen Steam Station.

Why this Project was Selected as the Preferred Solution
Cost and timing

South Point Switching Station, Construct

- **NERC Category P3 Violation**
- **Problem:** Post-generation retirement at Allen Steam Station, loss of one 230/100 kV transformers at Allen may overload the remaining transformer.
- **Solution:** Upgrade to larger transformers



Project ID and Name: 0053 – Wateree 115 kV Plant, Upgrade 115/100 kV Transformers

Project Description
This project consists of replacing the two existing 115/100 kV autotransformers at Wateree Plant with two new 168 MVA 115/100 kV autotransformers. While the two existing 115/100 kV Wateree transformers share a single breaker, the new transformers will be separately breakered so that either one can trip out with the other bank still transferring power between DEP and DEC. (The Wateree Plant is owned by DEC, but the existing 115/100 kV transformers and the 115 kV bus are owned by DEP.)

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/1/2023
Estimated Time to Complete	2 years
Estimated Cost	$10 M

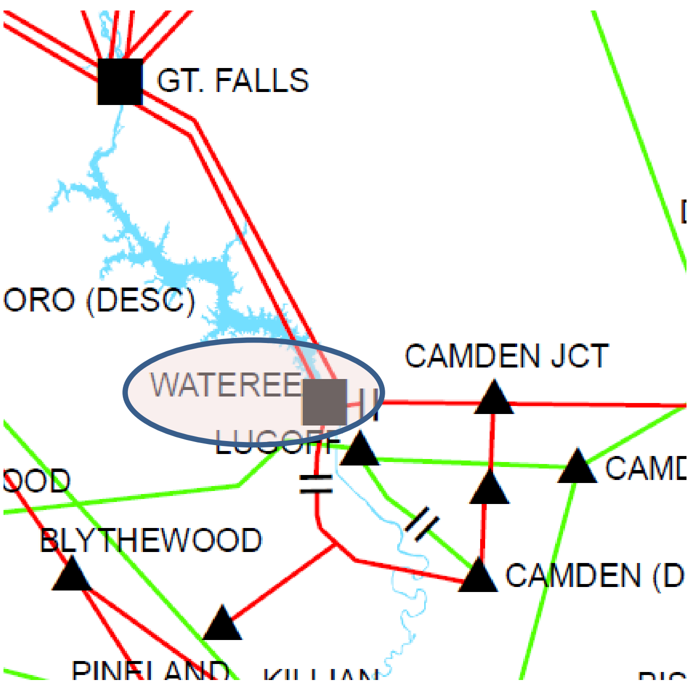
Narrative Description of the Need for this Project
By winter 2023-24, the NERC P3 outage of Robinson Nuclear plus outage of either the Richmond–Newport 500 kV line or the Camden–Lugoff 230 kV line causes an overload of the existing Wateree 115/100 kV transformers. In addition, the existing Wateree 115/100 kV transformers have reached end of life based on analysis from Asset Management.

Other Transmission Solutions Considered
New transmission lines.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

Wateree 115 kV Plant, Upgrade 115/100 kV Transformers

- **NERC Category P3 violation**
- **Problem:** By winter 2023-24, the NERC P3 outage of Robinson Nuclear plus outage of either the Richmond–Newport 500 kV line or the Camden–Lugoff 230 kV line causes an overload of the existing Wateree 115/100 kV transformers. In addition, the existing Wateree 115/100 kV transformers have reached end of life based on analysis from Asset Management.
- **Solution:** Upgrade existing transformers.



Project ID and Name: 0054 – Carthage 230/115 kV Substation, Construct Substation

Project Description
Construct a new 230/115 kV substation near the existing Carthage 115 kV substation. Loop in the existing Cape Fear–West End 230 kV line and West End–Southern Pines 115 kV feeder. The new Carthage 230–West End 115 kV line will be normally open at Carthage 230.kV.

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	12/1/2025
Estimated Time to Complete	4 years
Estimated Cost	$27 M

Narrative Description of the Need for this Project
By winter 2025-26, the NERC P1 outage of one West End transformer overloads the other and voltage at Southern Pines 115 kV drops below criteria.

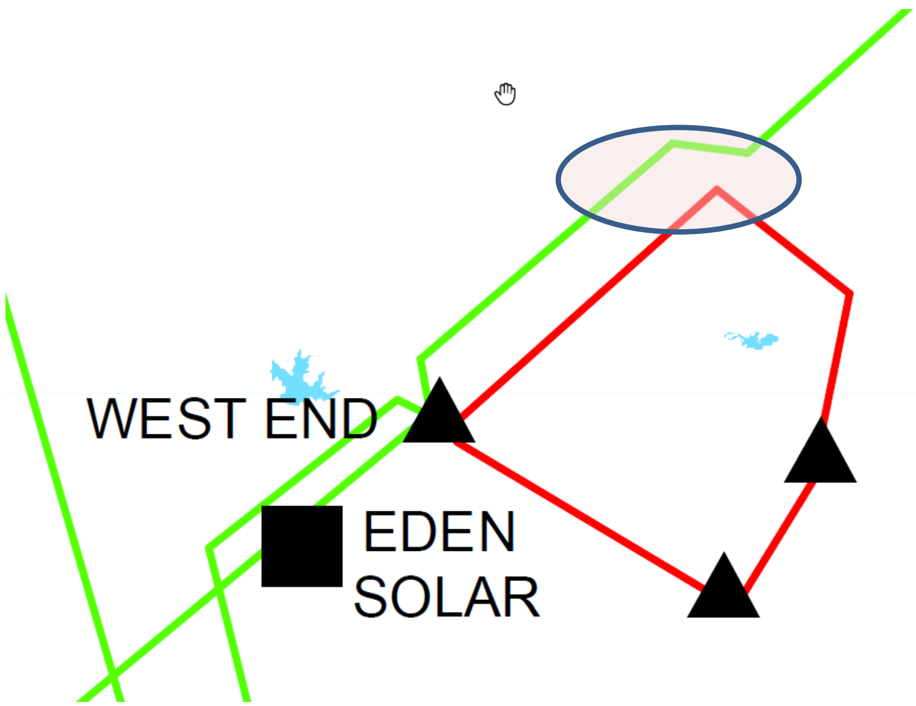
Other Transmission Solutions Considered
Convert several 115 kV substations to 230 kV.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

C–10

Carthage 230/115 kV Substation, Construct Substation

- **NERC Category P1 violation**
- **Problem:** By winter 2025-26, the NERC P1 outage of one West End transformer overloads the other and voltage at Southern Pines 115 kV drops below criteria.
- **Solution:** Construct new 230/115 kV substation in the Carthage area.



Project ID and Name: 0055 – Falls 230 kV Sub, Add 300 MVAR SVC

Project Description
At Falls 230 kV Substation add a 300 MVAR 230 kV Static Var Compensator (SVC).

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	12/1/2028
Estimated Time to Complete	4 years
Estimated Cost	$45 M

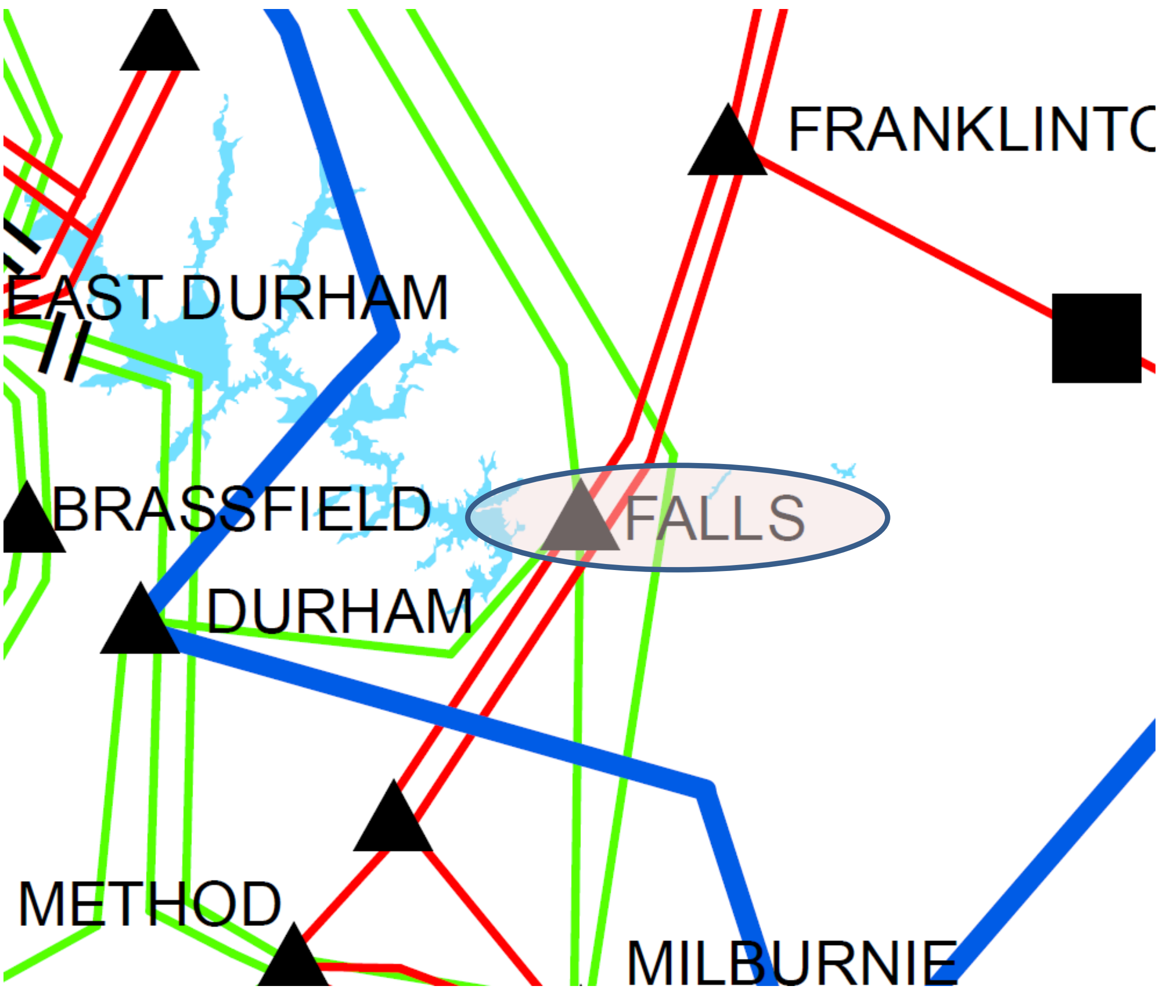
Narrative Description of the Need for this Project
With the future retirement of Roxboro and Mayo plants, several DEP areas were observed to have significant contingency voltage depression.

Other Transmission Solutions Considered
Replacement generation in the Roxboro area.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

Falls 230 kV Sub, Add 300 MVAR SVC

- **NERC Category P1 violation**
- **Problem:** With the future retirement of Roxboro and Mayo plants, several DEP areas were observed to have significant contingency voltage depression.
- **Solution:** Add 300 MVAR SVC at the Falls 230 kV Substation.



Project ID and Name: 0056 – Castle Hayne–Folkstone 115 kV Line, Rebuild

Project Description
Rebuild approximately 25.91 miles of 115 kV line (Castle Hayne 230 kV Sub to structure #251) with 1272 MCM ACSR or equivalent.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4 years
Estimated Cost	$85 M

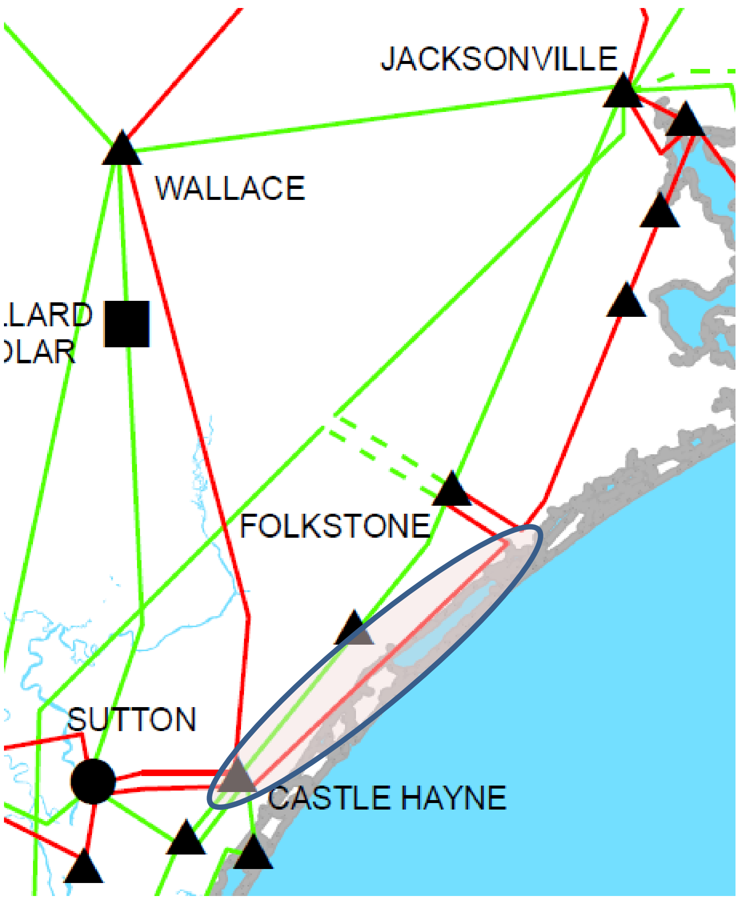
Narrative Description of the Need for this Project
By winter 2026/27, an outage of the Castle Hayne – Folkstone 230 kV line will cause the Castle Hayne 230 kV Sub-Folkstone 115 kV line to overload. This project will mitigate the overload problem.

Other Transmission Solutions Considered
New 230 kV transmission lines.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

Castle Hayne–Folkstone 115 kV Line, Rebuild

- **NERC Category P1 violation**
- **Problem:** By winter 2026/27, an outage of the Castle Hayne–Folkstone 230 kV line will cause the Castle Hayne 230 kV Sub-Folkstone 115 kV line to overload. This project will mitigate the overload problem.
- **Solution:** Rebuild approximately 25.91 miles of 115 kV line (Castle Hayne 230 kV Sub to structure #251) with 1272 MCM ACSR or equivalent.



Project ID and Name: 0057 – Holly Ridge North 115 kV Switching Station, Construct

Project Description
Construct a new 115 kV Switching Station northeast of Holly Ridge, NC where the Castle Hayne–Folkstone 115 kV and Folkstone–Jacksonville City 115 kV lines come together. Construct a new 115 kV feeder from the new switching station to Jones–Onslow EMC Folkstone POD.

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4 years
Estimated Cost	$20 M

Narrative Description of the Need for this Project
By winter 2026-27, the NERC P2-1 opening of the Folkstone end of the Castle Hayne–Folkstone 115 kV line results in low voltages at stations on this line.

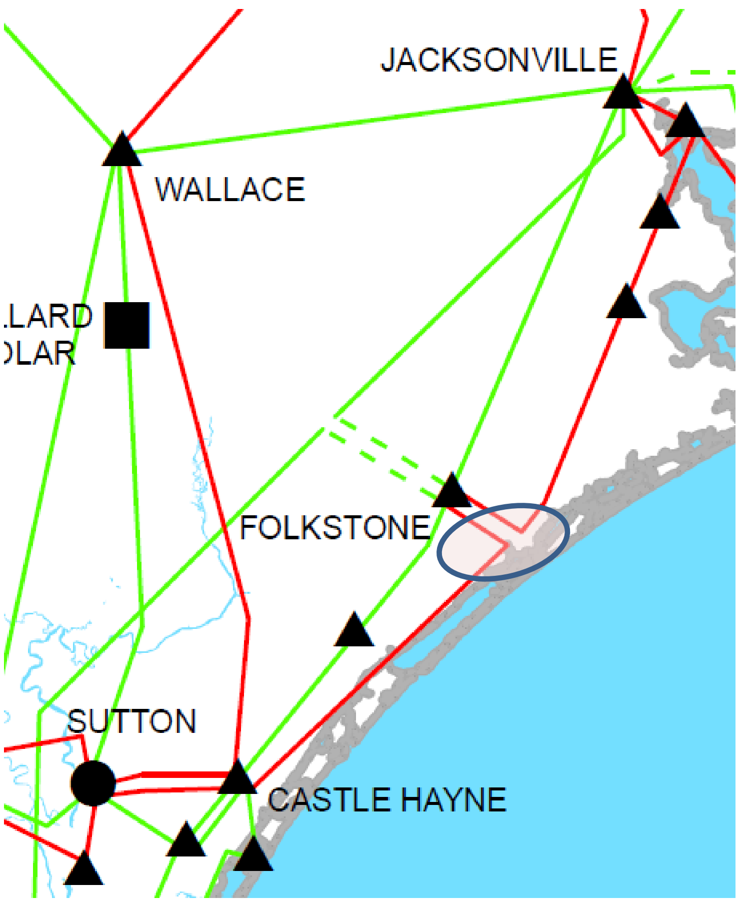
Other Transmission Solutions Considered
New 230 kV transmission lines.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

C–13

Holly Ridge North 115 kV Switching Station, Construct

- **NERC Category P2-1 violation**
- **Problem:** By winter 2026-27, the NERC P2-1 opening of the Folkstone end of the Castle Hayne – Folkstone 115 kV line results in low voltages at stations on this line.
- **Solution:** Construct new 115 kV switching station northeast of Holly Ridge.



Project ID and Name: 0058 – Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Add Second Circuit

Project Description
This project consists of rebuilding 8.9 miles of the existing 477 ACSR conductor with 954 ACSR and adding a second 954 ACSR circuit.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/25
Estimated Time to Complete	3.5 years
Estimated Cost	$15 M

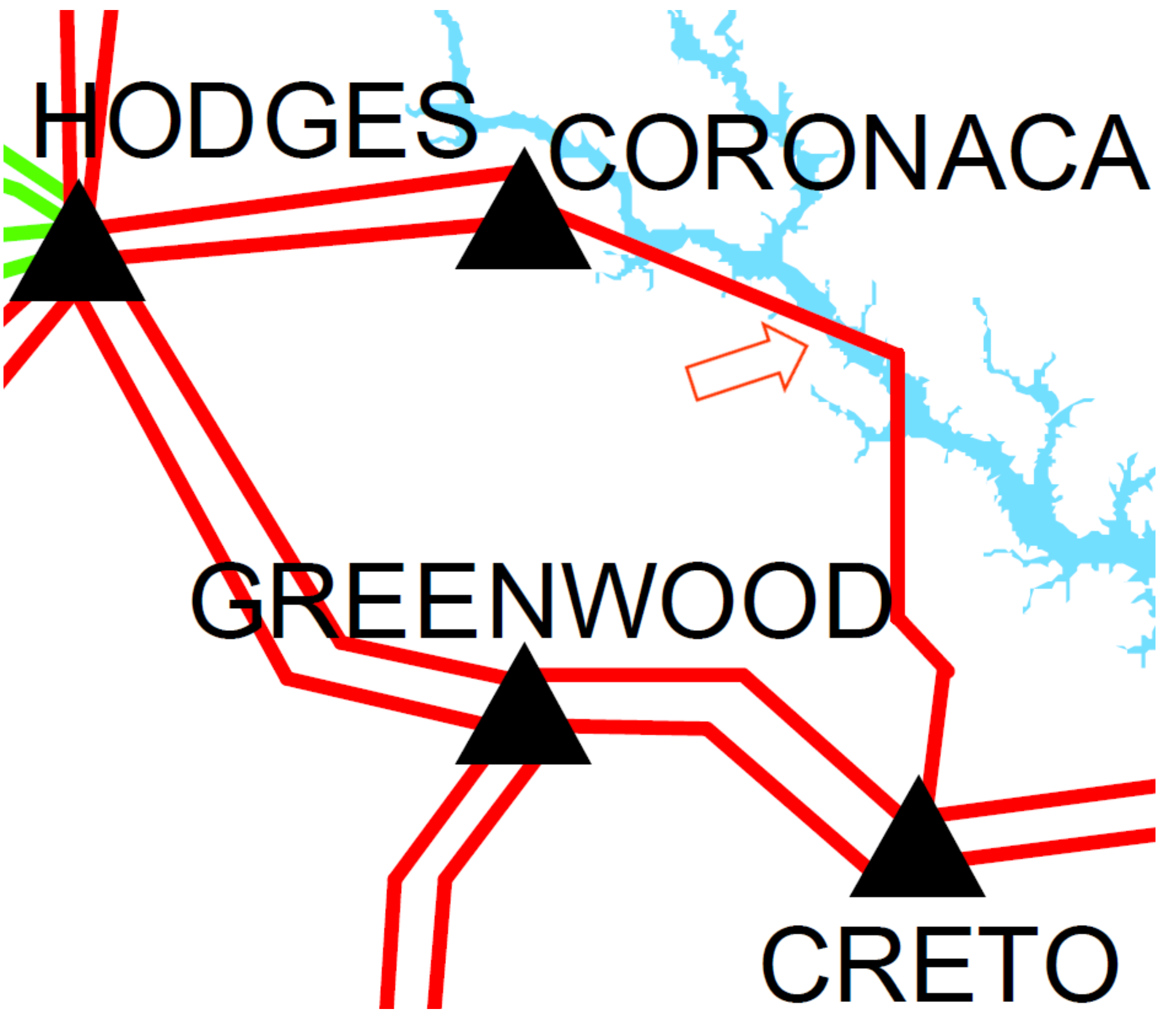
Narrative Description of the Need for this Project
These lines may become overloaded for loss of both Coronaca- Hodges circuits.

Other Transmission Solutions Considered
New transmission line(s).

Why this Project was Selected as the Preferred Solution
New transmission line(s) would require additional right-of-way, adding to the cost of the project.

Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Add Second Circuit

- **NERC Category P6 & P7 violation**
- **Problem:** Loss of both Coronaca-Hodges 100 kV lines may overload the Coronaca-Creto line.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors and add second circuit.



Project ID and Name: 0059 – Monroe 100 kV Line (Lancaster-Monroe), Upgrade

Project Description
This project consists of rebuilding 23.8 miles of the existing 2/0 Cu conductor with 1158 ACSS/TW.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	6/1/27
Estimated Time to Complete	5 years
Estimated Cost	$88 M

Narrative Description of the Need for this Project
These lines may become overloaded for loss of one of the circuits.

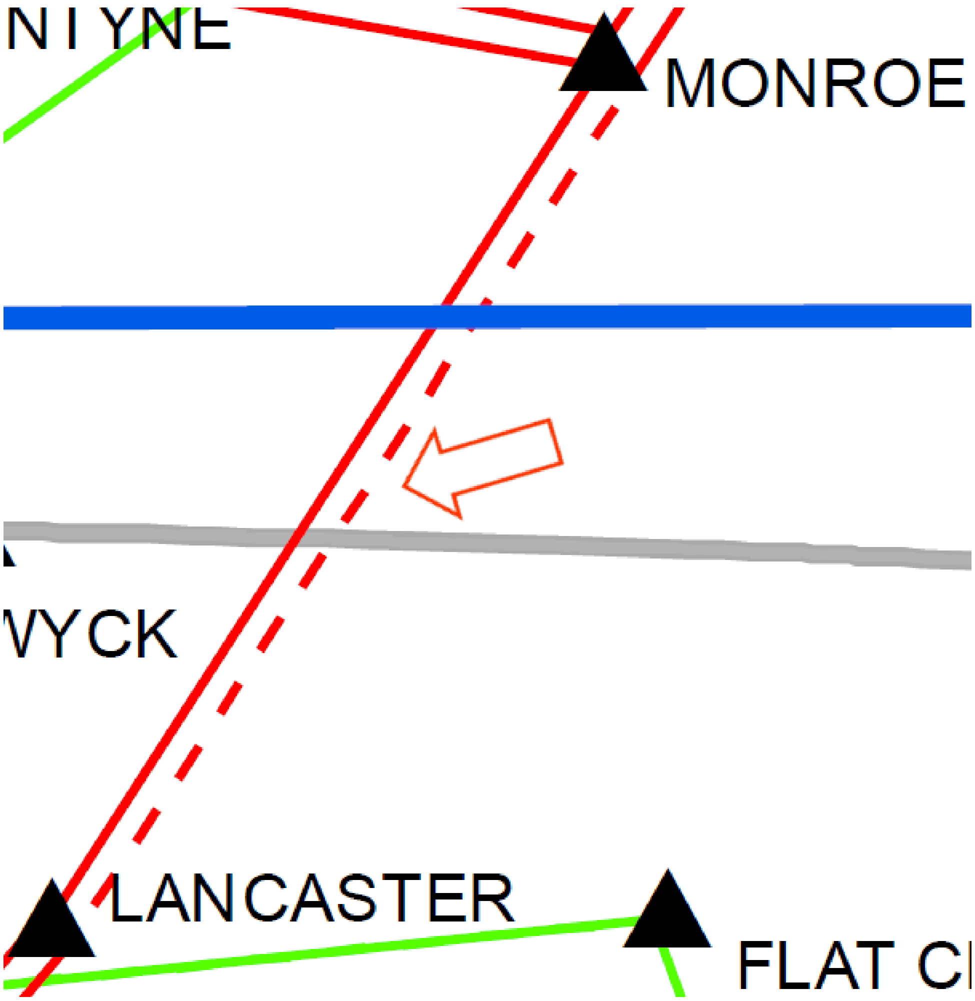
Other Transmission Solutions Considered
New transmission line(s) into Monroe Main.

Why this Project was Selected as the Preferred Solution
New transmission line(s) would require additional right-of-way, adding to the cost of the project.

C–15

Monroe 100 kV Line (Lancaster-Monroe), Upgrade

- **NERC Category P3 violation**
- **Problem:** Loss of one of the Lancaster-Monroe 100 kV lines (black circuit) may overload the remaining line (white circuit). Loss of a transformer at Morning Star may also overload existing 100 kV lines.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



Project ID and Name: 0060 – Westport 230 kV Line (McGuire-Marshall), Upgrade

Project Description
This project consists of rebuilding 13.8 miles of the existing 1272 ACSR conductor with 1533 ACSS/TW.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	5 years
Estimated Cost	$40 M

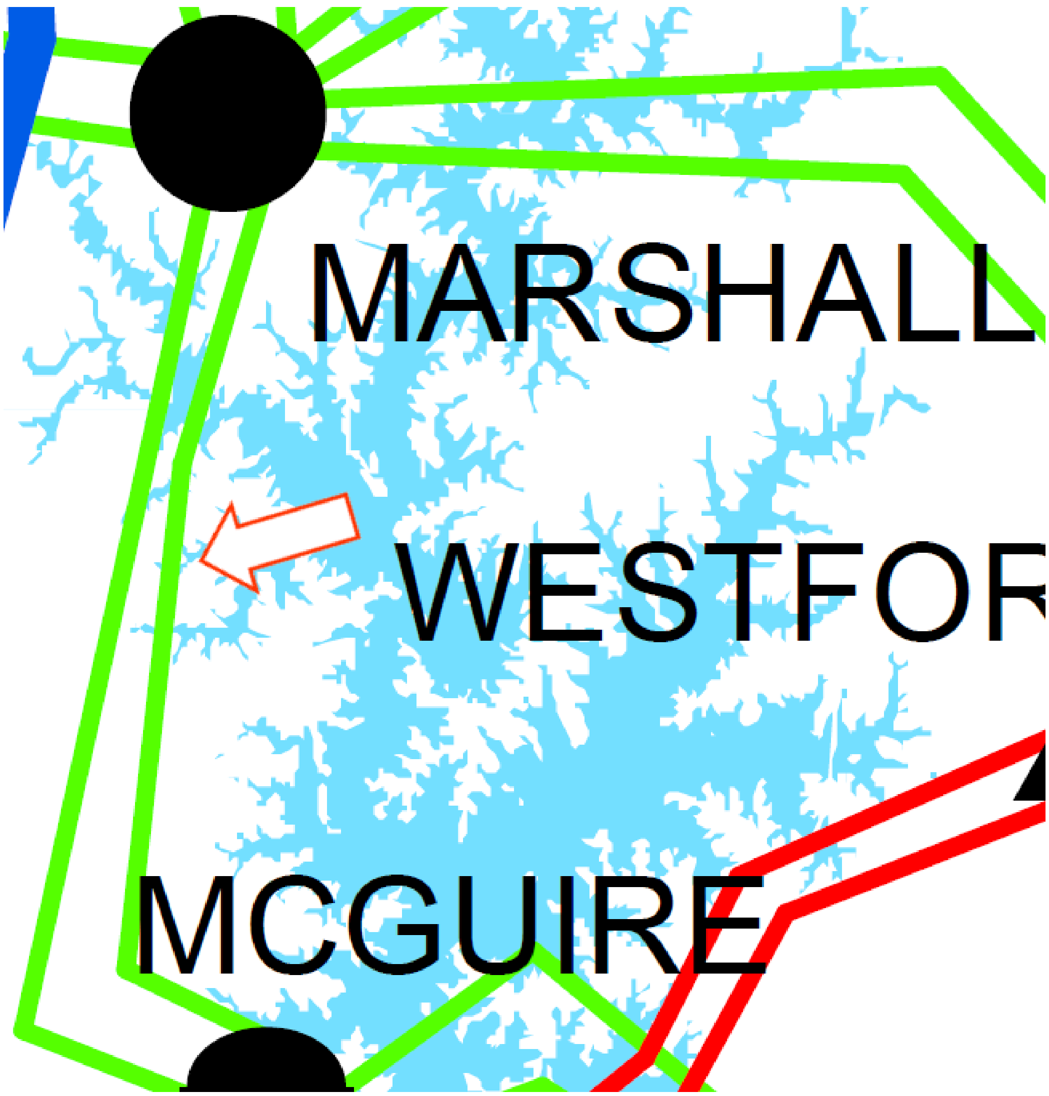
Narrative Description of the Need for this Project
These lines may become overloaded for loss of one of the circuits.

Other Transmission Solutions Considered
Series line reactors.

Why this Project was Selected as the Preferred Solution
Line reactors would drive the upgrade of a different, longer set of 230 kV lines.

Westport 230 kV Line (McGuire-Marshall), Upgrade

- **NERC Category P3 violation**
- **Problem:** Loss of one of the McGuire-Marshall 230 kV lines may overload the remaining line.
- **Solution:** Rebuild 230 kV lines with higher capacity conductors.



Appendix D
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2020 Plan[1]			2021 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0024	Durham–RTP 230 kV Line, Reconductor	DEP	Conceptual	TBD	20	Conceptual	TBD	20
0034	Sutton–Castle Hayne 115 kV North Line, Rebuild	DEP	Underway	6/1/2021	30	In-service	6/1/2021	30
0039	Asheboro–Asheboro East 115 kV North Line, Reconductor	DEP	Underway	6/1/2020	24	Underway	6/1/2022	12
0046	Windmere 100 kV Line (Dan River–Sadler), Construct	DEC	Underway	8/1/2023	26	Underway	12/1/2023	28
0048	Wilkes 230/100 kV Tie Station, Construct	DEC	Underway	6/1/2024	69	Underway	6/1/2024	69

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2020 Plan[1]			2021 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0050	Craggy–Enka 230 kV Line, Construct	DEP	Conceptual	12/1/2026	80	Planned	12/1/2025	74
0051	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	DEC	Planned	12/1/2024	16	Planned	12/1/2024	20
0052	South Point Switching Station, Construct	DEC	Planned	12/1/2024	110	Underway	12/1/2024	111
0053	Wateree 115 kV Plant, Upgrade 115/100 kV Transformers	DEP	Underway	12/1/2022	12	Underway	12/1/2023	10
0054	Carthage 230/115 kV Substation, Construct Sub	DEP	Conceptual	12/1/2027	15	Conceptual	12/1/2025	27

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2020 Plan[1]			2021 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0055	Falls 230 kV Sub, Add 300 MVAR SVC	DEP	Conceptual	12/1/2028	50	Conceptual	12/1/2028	45
0056	Castle Hayne–Folkstone115 kV Line, Rebuild	DEP	Conceptual	12/1/2028	52	Planned	12/1/2026	85
0057	Holly Ridge North 115 kV Switching Station, Construct	DEP	Conceptual	12/1/2028	25	Conceptual	12/1/2026	20
0058	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Add Second Circuit	DEC	–	–	–	Planned	12/1/2025	15
0059	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	DEC	–	–	–	Planned	6/1/2027	88

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2020 Plan[1]			2021 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0060	Westport 230 kV Line (McGuire-Marshall), Upgrade	DEC	–	–	–	Conceptual	TBD	40
TOTAL					804			694

[1] Information reported in Appendix B of the NCTPC 2019–2027 Collaborative Transmission Plan" dated January 17, 2020 and updated to reflect the mid-year plan report dated June 22, 2020 .

[2] Status: ***In-service**:* Projects with this status are in-service. This status was updated as of 12/1/2020.

***Underway**:* Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.

***Planned**:* Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

***Conceptual**:* Projects with this status are not p*lanned* at this time but will continue to be evaluated as a potential project in the future.

***Deferred**:* Projects with this status were identified in the 2019 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2020 Collaborative Transmission Plan.

Removed: Project is cancelled and no longer in the plan

[3] The estimated cost is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

Appendix E
Acronyms

ACRONYMS

ACSR	Aluminum Conductor Steel Reinforced
ACSS/TW	Aluminum Conductor Steel Supported/Trapezoidal Wire
AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
BAA	Balancing Authority Area
CC	Combined Cycle
CPLE	Carolina Power & Light East, or DEP East
CPLW	Carolina Power & Light West, or DEP West
CT	Combustion Turbine
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DNR	Designated Network Resource
DVP	Dominion Virginia Power
ERAG	Eastern Interconnection Reliability Assessment Group
EU	Energy United
FSA	Facilities Study Agreement
GTP	North Carolina Global TransPark
ISA	Interconnection Service Agreement
KMEC	Kings Mountain Energy Center
kV	Kilovolt
LGIA	Large Generator Interconnection Agreement
LSE	Load Serving Entity
LTWG	SERC Long-Term Working Group
M	Million
MCM	Thousand Circular Mils
MMWG	Multiregional Modeling Working Group
MVA	Megavolt-Ampere
MVAR	Megavolt-Ampere Reactive
MW	Megawatt
NCEMC	North Carolina Electric Membership Corporation

NCEMPA	North Carolina Eastern Municipal Power Agency
NCMPA1	North Carolina Municipal Power Agency Number 1
NCTPC	North Carolina Transmission Planning Collaborative
NERC	North American Electric Reliability Corporation
NTE	NTE Energy
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
OSC	Oversight Steering Committee
OTDF	Outage Transfer Distribution Factor
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
POD	Point of Delivery
PSS/E	Power System Simulator for Engineering
PWG	Planning Working Group
ROW	Right of Way
RTP	Research Triangle Park
SCEG	South Carolina Electric & Gas Company
SCPSA	South Carolina Public Service Authority
SE	Steam Electric (Plant)
SEPA	South Eastern Power Administration
SERC	SERC Reliability Corporation
SOCO	Southern Company
SS	Switching Station
SVC	Static VAR Compensator
TAG	Transmission Advisory Group
TRM	Transmission Reliability Margin
TSR	Transmission Service Request
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas Reliability Agreement
VAR	Volt Ampere Reactive