North Carolina Transmission Planning Collaborative

Report on the NCTPC 2017-2027 Collaborative Transmission Plan

December 15, 2017
FINAL DRAFT Report

2017 – 2027 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 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 2016-2026 Collaborative Transmission Plan (the "2016 Collaborative Transmission Plan" or the "2016 Plan") was published in January 2017.

This report documents the current 2017 – 2027 Collaborative Transmission Plan ("2017 Collaborative Transmission Plan" or the "2017 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2017 reliability planning study scope and methodology. The NCTPC Process document and 2017 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2017 reliability planning process was focused on the annual base reliability study. The base reliability study assessed 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 was to evaluate the transmission systems' ability to meet load growth projected for 2017 through 2027 with the Participants' planned Designated Network Resources ("DNRs").

The 2017 Study[1] model included the following modelling assumptions related to CPLW upgrades:

- DEP assumed that Asheville 1 and 2 coal units will be shut down in all three study cases, and the two planned Asheville combined cycle ("CC") units (260/280 MW Summer/Winter each, 520/560 MW Summer/Winter total) were added to all three study cases.

- One of the planned Asheville CC units was connected to the Asheville 230 kV switchyard and the other was connected to the Asheville 115 kV switchyard. The 2022 summer case includes a CPLW import of 36 MW (22 MW from SCPSA, and 14 MW from TVA).

- The 2022/2023 winter case includes a CPLW import of 286 MW (100 MW from CPLE, 150 MW from DEC-Rowan, 22 MW from SCPSA, and 14 MW from TVA). The 2027/2028 winter case includes a CPLW import of 386 MW (200 MW from

[1] The term "2017 Study" is a generic term referring to all the study work that was done in 2017 which includes the reliability analysis as well the additional stress tests to the transmission systems of DEC and DEP as a part of the Reliability Planning Process.

CPLE, 150 MW from DEC-Rowan, 22 MW from SCPSA, and 14 MW from TVA).

- To meet the remaining CPLW load, CPLW generation was dispatched in the following order: Walters, Marshall, planned Asheville CC units, and finally the existing Asheville CTs. The projects needed for the installation of these units were modeled in the cases.

Based on the study's input assumptions, the 2017 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2017 Study also allowed for adjustments to existing plans where necessary.

The NCTPC reliability study results affirmed that the planned DEC and DEP transmission projects identified in the 2016 Plan continue to satisfactorily address the reliability concerns identified in the 2017 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2017 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

The 2017 Plan includes 17 reliability projects with a total estimated cost of $426 million. This compares to the original 2016 Plan estimate of $214 million for 10 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix D for a detailed comparison of this year's Plan to the 2016 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 completed or eliminated from the list. Appendix C provides a more detailed description of each project in the 2017 Plan.

The 2017 Plan, relative to the 2016 Plan, includes 4 new DEC projects and 3 new DEP projects.

The 4 new DEC projects in the 2017 Plan are:

- Rural Hall SVC (100 kV) Installation
- New Tie Station in Catawba County, NC (230/100 kV) Construction

- Reidsville 100 kV (Dan River-Sadler) Reconductor
- Wolf Creek 100 kV (Dan River-Sadler) Reconductor

The 3 new DEP projects in the 2017 Plan are:

- Asheboro-Asheboro East 115kV North Line Reconductor
- Delco 230kV Substation, Convert to Double Breaker
- Castle Hayne 230kV Substation, Convert to Double Breaker

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

- Raeford 230 kV substation, project to loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and the added third bank had an increase in estimated cost.
- Durham - RTP 230 kV Line Reconductor had its in-service date pushed out.
- Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation project had an increase in estimated cost.
- Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation had an increase in estimated cost.
- Fort Bragg Woodruff St. 230 kV Sub, project to replace 150 MVA 230/115 kV transformer with two 300 MVA banks and reconductor Manchester 115 kV feeder was placed in service 2/24/2017.
- Sutton - Castle Hayne 115 kV North line Rebuild had an increase in estimated cost.
- Asheville Plant Project had an increase in estimated cost.
- Cane River 230 kV Substation, Construct 150 MVAR SVC had an increase in estimated cost.
- Harley 100 kV Lines (Tiger - Campobello) Reconductor had a decrease in estimated cost, and its in-service date was pushed out.

No Local Economic Study or Public Policy Study requests were received from TAG stakeholders by the February 3rd deadline for the 2017 NCTPC Study. Therefore, there were no Local Economic Study Planning Process nor evaluations of Public Policy impacts as a part of the 2017 NCTPC Study.

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. 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.

In 2017, the Planning Working Group ("PWG") analyzed resource supply options that examined the impacts of sixteen different hypothetical transfers into and out of the DEC and DEP systems. Each of these transfers were examined individually, and not in combination with other transfers. These resource supply scenarios included the following:

Resource Supply Options
2027 Hypothetical Transfer Scenarios

Resource From	Sink	Test Level (MW)
PJM	DUK[1]	1,000
SOCO	DUK	1,000
SCEG	DUK	1,000
SCPSA	DUK	1,000
CPLE[2]	DUK	1,000
TVA	DUK	1,000
PJM	CPLE	1,000
SCEG	CPLE	1,000
SCPSA	CPLE	1,000
DUK	CPLE	1,000
DUK	SOCO	1,000
PJM	DUK / CPLE	1,000 / 1,000
DUK / CPLE	PJM	1,000 / 1,000
CPLE	PJM	1,000
DUK	PJM	1,000
SOCO[3]	CPLE	1,000

[1] DUK is the Balancing Authority for DEC

[2] CPLE is the eastern Balancing Authority for DEP

[3] This hypothetical transfer is intended to evaluate the impact of a 1000 MW SOCO transaction through the DEC transmission system into CPLE.

Analysis of the sixteen hypothetical transfer scenarios did not require any additional transmission projects for DEC or DEP beyond those in the 2017 Collaborative Plan.

In this 2017 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, North Carolina Electric Membership Corporation, and ElectriCities of North Carolina) 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 BAAs 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. 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 Local Planning Process includes a reliability planning process (base reliability study) that 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. A resource supply options process is conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements. 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 second part of the Local Planning Process is the Local Economic Study Process. This allows the TAG participants to propose economic upgrades to be studied as part of the Local Planning Process. The Local Economic Study Process evaluates the means to increase transmission access to potential supply resources inside and outside the Balancing Authority Areas of the Companies. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources.

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 Oversight Steering Committee ("OSC") manages the NCTPC Process. The PWG supports the development of the NCTPC Process and coordinates the study development. The Transmission Advisory Group

("TAG") provides advice and makes recommendations regarding the development of the NCTPC Process and the study results.

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

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 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 purchase power agreement expirations. 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. 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 results of the reliability planning process include summaries of the estimated costs and schedules to provide any 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.

II.C. Resource Supply Options Process

In addition, the resource supply options process is performed as part of the Local Planning Process to evaluate transmission system impacts for other potential resource supply options to meet future load requirements. In this process 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 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 purchase power agreement expirations. 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. 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 results of the reliability planning process include summaries of the estimated costs and schedules to provide any 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 2017 study, the NCTPC evaluated resource supply scenarios that modeled hypothetical transfers across the NCTPC interface with neighboring systems.

II.D. Local Economic Study Process

The local economic study process allows the TAG participants to propose economic hypothetical 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 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 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 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 Collaborative 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.

The 2017 NCTPC Process contains no local economic studies as no requests were received from stakeholders by February 3, 2017. Local economic study process scenarios will be solicited again for the 2018 Study and included if appropriate.

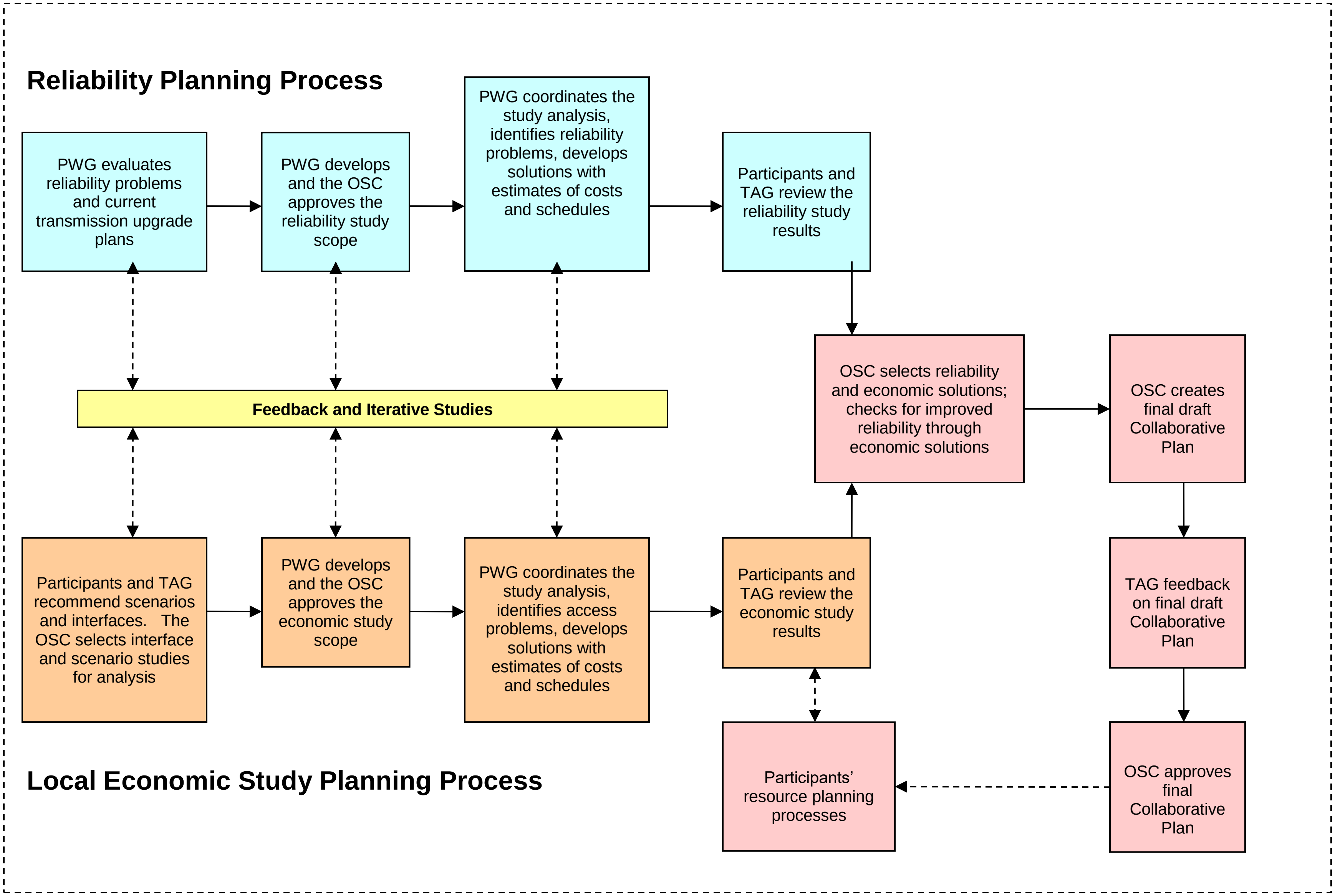
II.E. Local Public Policy Process

As part of the local economic study process there is a local public policy process. Through this process the OSC will seek input allows the TAG participants to identify any public policies impacts to be evaluated as part of the transmission planning process that may drive the need for local transmission upgrades. The OSC may itself identify public policies. Using the criteria below, the OSC will determine if there are any public policies driving the need for local transmission as follows:

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

The 2017 NCTPC Process contains no evaluations of local public policy impacts as no local public policy requests were received from stakeholders by February 3, 2017. Local public policy requests will be solicited again for the 2018 Study and included if appropriate.

2017 NCTPC Process Flow Chart



II.F. Collaborative Transmission Plan

Once the reliability and local economic studies are completed, 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 final plan. If so, the initial plan developed based on the results of the reliability studies is modified accordingly. This process results in a single Collaborative 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 Collaborative Transmission Plan.

The Collaborative 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. 2017 Reliability Planning Study Scope and Methodology

The scope of the 2017 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 2017 Study models assume that DEP's Asheville 1 and 2 coal units were shut down in all three study cases, and the two planned Asheville combined cycle (CC) units (260/280 MW Summer/Winter each, 520/560 MW total Summer/Winter total) were added to all three study cases. One of the planned Asheville CC units was connected to the Asheville 230 kV switchyard and the other was connected to the Asheville 115 kV switchyard. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2022 summer through 2027/2028 winter with the Participants' planned Designated Network Resources ("DNRs"). The 2017 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2017 Study also allowed for adjustments to existing plans where necessary.

The Local Economic Study Process allows the TAG participants to propose economic hypothetical transfers to be studied as part of the transmission 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. In 2017, no Local Economic Study requests were received from TAG stakeholders, therefore no Local Economic Study was performed.

For a variety of reasons (such as load growth, generation retirements, or power purchase agreements expiring), some Load Serving Entities (LSEs) may wish to evaluate other resource supply options to meet future load demand. 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. In 2017, the resource supply options evaluated included modeling of hypothetical transfers across the NCTPC interface with neighboring systems as detailed in section V.

Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined. The power flow analysis assumed an N-1 evaluation and was performed based on the assumption that thermal limits would be the controlling limit.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2017 Plan addressed a ten-year planning horizon through 2027. The study years chosen for the 2017 Study are listed in Table 4.

Table 4

Study Years

Study Year / Season	Analysis
2022 Summer	Near-term base reliability
2022/2023 Winter	Near-term base reliability
2027/2028 Winter	Long-term base reliability

To identify projects required in years other than the base study years of 2022 and 2027/2028, line loading results for those base study years were extrapolated into future years assuming the line loading growth rates in Table 5. This allowed assessment of transmission needs throughout the planning horizon. The line loading growth rates are based on each BAA's individual load growth projection at the time the study process was initiated.

Table 5

Line Loading Growth Rates

Company	Line Loading Growth Rate
DEC	1.2 % per year (summer) 1.3% per year (winter)
DEP	1.1% per year (summer) 1.3% per year (winter)

2. Network Modeling

The network models developed for the 2017 Study included new transmission facilities and upgrades for the 2022 and 2027/2028 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2016 Plan. Table 6 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2022 and 2027/2028 models. Table 7 lists the generation facility changes included in the 2022 and 2027/2028 models.

Table 6
Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2022	2027/2028
DEP	Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg WS 230 kV Line and add 3rd bank	Yes	Yes
DEP	Jacksonville - Grants Creek 230 kV Line, Grants Creek 230/115 kV Substation	Yes	Yes
DEP	Newport - Harlowe 230 kV Line, Newport Switching Station, Harlowe 230/115 kV Substation	Yes	Yes
DEP	Durham - RTP 230 kV Line	No	Yes
DEP	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV substation	No	Yes
DEP	Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV transformer with two 300 MVA banks & reconductor Manchester 115 kV feeder	Yes	Yes
DEP	Sutton - Castle Hayne 115 kV North line rebuild	Yes	Yes

Company	Transmission Facility	2022	2027/2028
DEP	Asheville Plant, Replace 2-300 MVA 230/115 kV banks with 2-400 MVA banks, reconductor 115 kV ties to switchyard, upgrade breakers, and add 230 kV capacitor bank	Yes	Yes
DEP	Cane River 230 kV Substation, Construct 150 MVAR SVC	Yes	Yes
DEP	Asheboro-Asheboro East 115kV North Line, Reconductor	Yes	Yes

Table 7
Major Generation Facility Changes in Models

Company	Generation Facility	2022	2027/2028
DEC	Added Lee CC (776 MW)	Yes	Yes
DEC	Added Kings Mountain Energy CC (452 MW)	Yes	Yes
DEP	Asheville 1-2 not dispatched	Yes	Yes
DEP	Added Asheville CC (2 x 280 MW)	Yes	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. 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 201 MW of transmission-connected solar generation, 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 2022 summer power flow case has approximately 568 MW of transmission-connected and 1286 MW of distribution-connected solar generation for a total of 1854 MW. In its summer peak cases, DEP scales the solar generation down to 35% of its maximum capacity to approximate the amount of solar generation that will be on-line coincident with the DEP peak load. For winter peak studies, DEP makes the assumption 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.

Interchange in the base cases was set according to the DNRs identified outside the DEC and DEP BAAs. Interchange tables for the summer and winter base cases, and the DEP Transmission Reliability Margin ("TRM") cases[2], discussed in Section III.D, are in Appendix A.

The summer case included a CPLW import of 36 MW, 22 MW from SCPSA, and 14 MW from TVA. The 2022/2023 winter case included a CPLW import of 286 MW, 100 MW from CPLE, 150 MW from DEC-Rowan, 22 MW from

[2] Since DEP is an importing system, the worst case for studying transfers into DEP is to start with a case that models all firm transfer commitments, including DNRs and TRM. DEP calls this maximum transfer case its TRM case.

SCPSA, and 14 MW from TVA. The 2027/2028 winter case included a CPLW import of 386 MW, 200 MW from CPLE, 150 MW from DEC-Rowan, 22 MW from SCPSA, and 14 MW from TVA. To meet the remaining CPLW load, CPLW generation was dispatched in the following order: Walters, Marshall, planned Asheville CC units, and finally the existing Asheville CTs. DEP included two required upgrades: replacing the Asheville 230/115 kV and Pisgah 115/100 kV autotransformers with larger units. These transformer upgrades were modeled in this study.

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 2016 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.

Generator maintenance cases were developed for the following units:

Allen 4	Allen 5	Bad Creek 1
Belews Creek 1	Catawba 1	Cliffside 5
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

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. To model this worst case import scenario for TRM, cases were developed from the 2022 summer, 2022/2023 winter and 2027/2028 winter peak base cases. The cases included a Brunswick 1 unit outage, a Harris unit outage, a Robinson 2 unit outage, or an Asheville CC1 unit outage, with the remainder of TRM addressed by miscellaneous unit de-rates.

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 2017 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 2017 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 2016 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 Study Group ("LTSG") studies performed for similar timeframes. LTSG studies have recently been performed for 2020 and 2021 summer timeframes. The limiting facilities identified in the PWG study of base reliability have been previously identified in the LTSG 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 2017 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 2017 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 2017 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 17 reliability projects included in the 2017 Plan is $426 million as documented in Appendix B. This compares to the 2016 Plan estimate of $214 million for 10 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix D for a detailed comparison of this year's Plan to the 2016 Plan.

V. Resource Supply Options Results

For a variety of reasons (such as load growth, generation retirements, or power purchase agreements expiring), some LSEs may wish to evaluate other resource supply options to meet future load demand. 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. In 2017, the PWG analyzed, among its resource supply options, cases that examine the impacts of 16 different hypothetical transfers into, out of and through the DEC and DEP systems – Table 10. Each of these transfers, identified in Table 10, were examined individually, and not in combination with other transfers. Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined.

Table 10
Resource Supply Options
2027 Hypothetical Transfer Scenarios

Resource From	Sink	Test Level (MW)
PJM	DUK[3]	1,000
SOCO	DUK	1,000
SCEG	DUK	1,000
SCPSA	DUK	1,000
CPLE	DUK	1,000
TVA	DUK	1,000
PJM	CPLE[4]	1,000
SCEG	CPLE	1,000
SCPSA	CPLE	1,000
DUK	CPLE	1,000
SOCO	CPLE	1,000
DUK	SOCO	1,000
PJM	DUK/CPLE	1,000 / 1,000

[3] DUK is the Balancing Authority Area for DEC

[4] CPLE is the eastern Balancing Authority Area for DEP

DUK/CPLE	PJM	1,000 / 1,000
CPLE	PJM	1,000
DUK	PJM	1,000

No major issues for DEC or DEP were identified for the 16 hypothetical transfers. Any issues identified were either previously identified for the base reliability studies or can be mitigated with ancillary equipment upgrades.

VI. Collaborative Transmission Plan

The 2017 Plan includes 17 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 17 reliability projects in the 2017 Plan is $426 million. This compares to the 2016 Plan estimate of $214 million for 10 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix D for a detailed comparison of this year's Plan to the 2016 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 completed or eliminated from the list. Appendix C provides a more detailed description of each project in the 2017 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 2016 Report and have been deferred beyond the end of the planning horizon based on the 2017 Study results.

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

2022 SUMMER PEAK, 2022/2023 WINTER PEAK, 2027/2028 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE (BASE)

Duke Energy Carolinas Modeled Imports – MW

	22S	22/23W	27/28W
CPLE (NCEMC-Hamlet)	165	165	165
PJM (DVP)	2	2	2
SCEG (Chappells)	2	2	2
SCPSA (PMPA)	202	88	115
SCPSA (Seneca)	42	31	33
SEPA (Hartwell)	155	155	155
SEPA (Thurmond)	113	113	113
SOCO (EU)	11	68	0
Total	**692**	**624**	**585**

Duke Energy Carolinas Modeled Exports – MW

	22S	22/23W	27/28W
CPLE (Broad River)	850	850	850
CPLE (NCEMC-Catawba)	205	205	205
CPLE (CPLC)	150	0	150
CPLW (Rowan)	0	150	0
PJM (NCEMC-Catawba)	100	100	100
SCPSA (Haile)	10	10	10
Total	**1315**	**1315**	**1315**

Duke Energy Carolinas Net Interchange – MW

	22S	22/23W	27/28W
	623	**691**	**730**

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

2022 SUMMER PEAK, 2022/2023 WINTER PEAK, 2027/2028 WINTER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (East) Modeled Imports – MW

	22S	22/23W	27/28W
PJM (NCEMC-AEP)	100	100	100
DUK (Broad River)	850	850	850
DUK (NCEMC-Catawba)	205	205	205
DUK (CPLC)	150	0	0
PJM (SEPA-KERR)	95	95	95
Total	**1400**	**1250**	**1250**

Duke Energy Progress (East) Modeled Exports – MW

	22S	22/23W	27/28W
CPLW (Transfer)	0	100	200
PJM (Ingenco)	6	6	6
PJM (NCEMC-Hamlet)	165	165	165
DUK (NCEMC-Hamlet)	165	165	165
Total	**336**	**436**	**536**

Duke Energy Progress (East) Net Interchange - MW

	22S	22/23W	27/28W
	-1064	**-814**	**-714**

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

2022 SUMMER PEAK, 2022/2023 WINTER PEAK, 2027/2028 WINTER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (West) Modeled Imports – MW

	22S	22/23W	27/28W
CPLE (Transfer)	0	100	200
DUK (Rowan)	0	150	150
SCPSA (Waynesville)	22	22	22
TVA (SEPA)	14	14	14
Total	**36**	**286**	**386**

Duke Energy Progress (West) Modeled Exports – MW

	22S	22/23W	27/28W
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Total	**---**	**---**	**---**

Duke Energy Progress (West) Net Interchange – MW

	22S	22/23W	27/28W
	-36	**-286**	**-386**

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

2022 SUMMER PEAK, 2022/2023 WINTER PEAK, 2027/2028 WINTER PEAK

DUKE ENERGY PROGRESS (WEST), DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE (TRM)

Duke Energy Progress (West) Modeled Imports – MW

	22S, 22/23W, 27/28W
AEP (TRM)	70
DUK (TRM)	191
TVA (TRM)	19
Total	**280**

Duke Energy Progress (East) Modeled Imports – MW

	22S, 22/23W, 27/28W
AEP (TRM)	100
DUK (TRM)	773
DVP (TRM)	427
SCEG (TRM)	200
SCPSA (TRM)	326
Total	**1826**

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

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

Appendix B
Transmission Plan Major Project Listings - **Reliability Projects**

2017 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0024	Durham - RTP 230 kV Line, Reconductor	Planned	DEP	TBD	15	4
0028	Brunswick #1 – Jacksonville 230 kV Line, Loop into Folkstone 230 kV Substation	Planned	DEP	6/1/2024	14	4
0030	Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank	Planned	DEP	6/1/2018	20	0.5
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	Planned	DEP	6/1/2020	51	2.5
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	Planned	DEP	6/1/2020	40	2.5
0033	Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV Transformer with Two 300 MVA Banks & Reconductor Manchester 115 kV Feeder	In-Service	DEP	2/24/2017	19	-
0034	Sutton - Castle Hayne 115 kV North Line - Rebuild	Underway	DEP	6/1/2019	11	1.5

2017 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)							
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0036	Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank	Planned	DEP	12/1/2019	40	2
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	Planned	DEP	12/1/2019	42	2
0038	Harley 100 kV Lines (Tiger -Campobello) Reconductor	Planned	DEC	12/1/2021	18	3
0039	Asheboro-Asheboro East 115kV North Line Reconductor	Underway	DEP	6/1/2019	12	1.5
0040	Delco 230kV Substation, Convert to Double Breaker	Underway	DEP	6/1/2019	13	1.5
0041	Castle Hayne 230kV Substation, Convert to Double Breaker	Underway	DEP	6/1/2019	10	1.5
0042	Rural Hall 100 kV, Install SVC	Planned	DEC	6/1/2020	50	2

2017 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0043	230/100 kV Tie Station, Catawba County NC	Planned	DEC	12/1/2021	45	2.5
0044	Reidsville 100 kV Lines (Dan River-Sadler) Reconductor	Conceptual	DEC	TBD	13	3
0045	Wolf Creek 100 kV Lines (Dan River-Sadler) Reconductor	Conceptual	DEC	TBD	13	3
TOTAL					**426**	

[1] Status: *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 *Planned* at this time but will continue to be evaluated as a potential project in the future.

[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	Planned
Transmission Owner	DEP
Planned In-Service Date	TBD
Estimated Time to Complete	4 years
Estimated Cost	$15 M

Narrative Description of the Need for this Project
With Harris Plant down, a common tower outage of the Method - (DPC) 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.

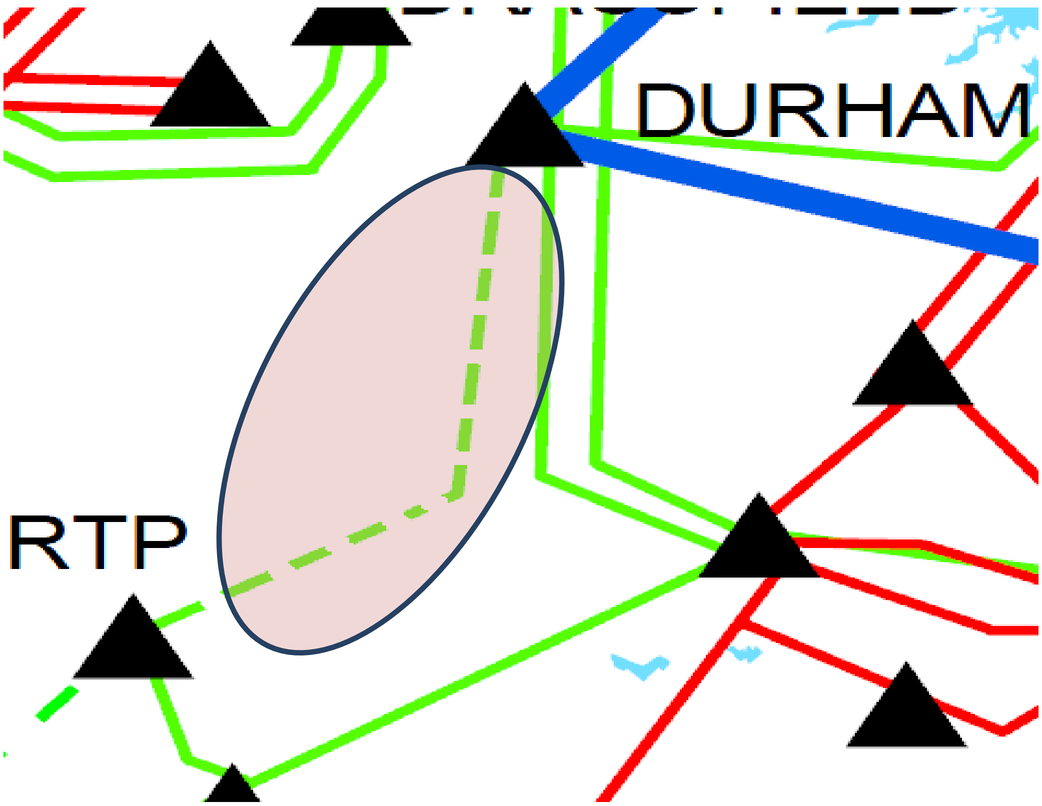
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV subs.

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: 0028 – Brunswick #1 – Jacksonville 230 kV Line, Loop into Folkstone 230 kV Substation

Project Description
Loop existing Brunswick Plant Unit 1 – Jacksonville 230 kV Line into the Folkstone 230 kV Substation. Also convert the Folkstone 230 kV bus configuration to breaker-and-one-half by installing three (3) new 230 kV breakers.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2024
Estimated Time to Complete	4 years
Estimated Cost	$14 M

Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Castle Hayne-Folkstone 115 kV Line under the contingency of losing Castle Hayne-Folkstone 230 kV Line.

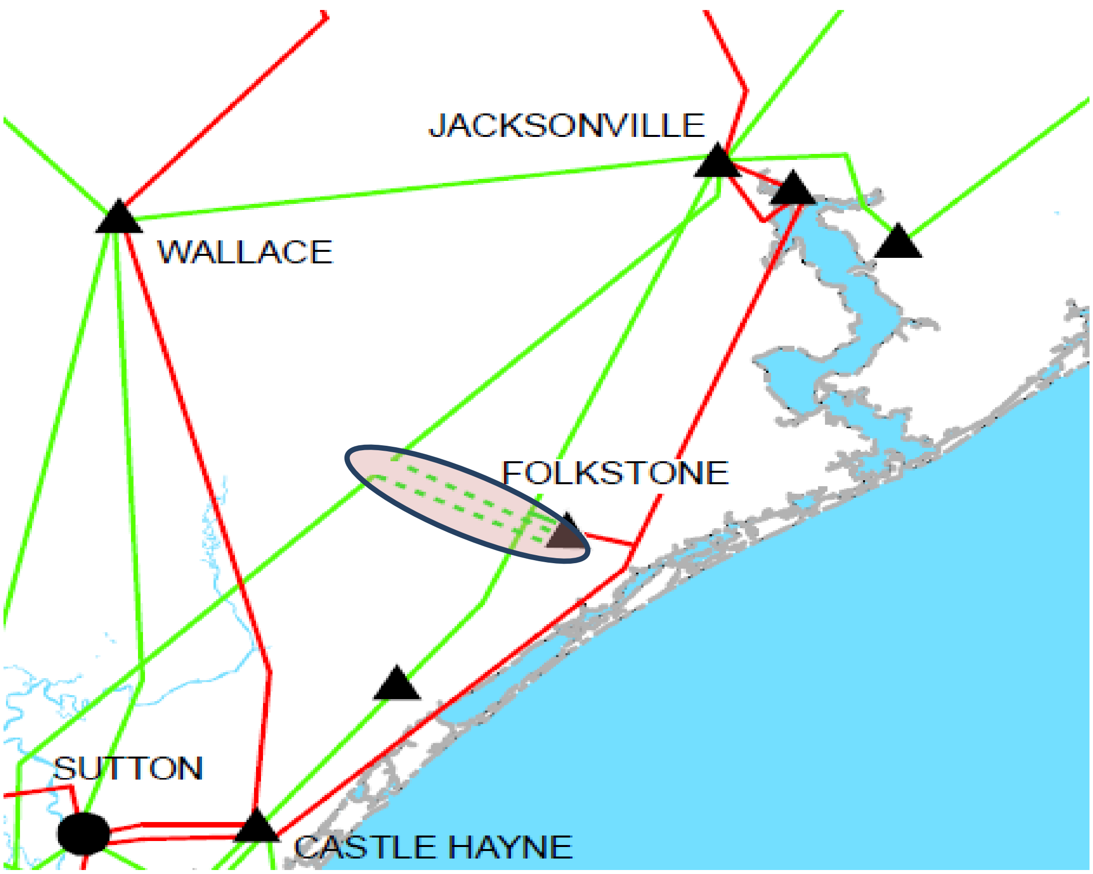
Other Transmission Solutions Considered
Rebuild, reconductor existing Castle Hayne-Folkstone 115 kV line.

Why this Project was Selected as the Preferred Solution
The selected project fixes additional transmission contingencies that the alternate solution does not.

C-2

Brunswick #1 – Jacksonville 230 kV Line Loop Into Folkstone 230 kV Substation

- **NERC Category P1 Violation**
- **Problem:** Outage of the Folkstone – Jacksonville 230 kV Line can cause the thermal rating of the Folkstone – Jacksonville City 115 kV Line to be exceeded.
- **Solution:** Loop existing Brunswick Plant Unit 1 – Jacksonville 230 kV Line into the Folkstone 230 kV Substation.



Project ID and Name: 0030 – Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank

Project Description
This project will require the loop-in of the Richmond – Ft. Bragg Woodruff St. 230 kV Line into the Raeford 230kV Substation and add a 300 MVA 230/115kV transformer.

Status	Planned:
Transmission Owner	DEP
Planned In-Service Date	6/1/2018
Estimated Time to Complete	1 year
Estimated Cost	$15 M

Narrative Description of the Need for this Project
By 2018, with a Brunswick Unit down, loss of the common tower Fayetteville – Rockingham 230 kV and Fayetteville – Raeford 230 kV Lines may cause the Weatherspoon – Raeford 115 kV Line to overload. In addition, by 2018, the N-1-1 contingency of losing both of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation may overload the Laurinburg - Raeford 115 kV Line. This project will mitigate each of these contingencies.

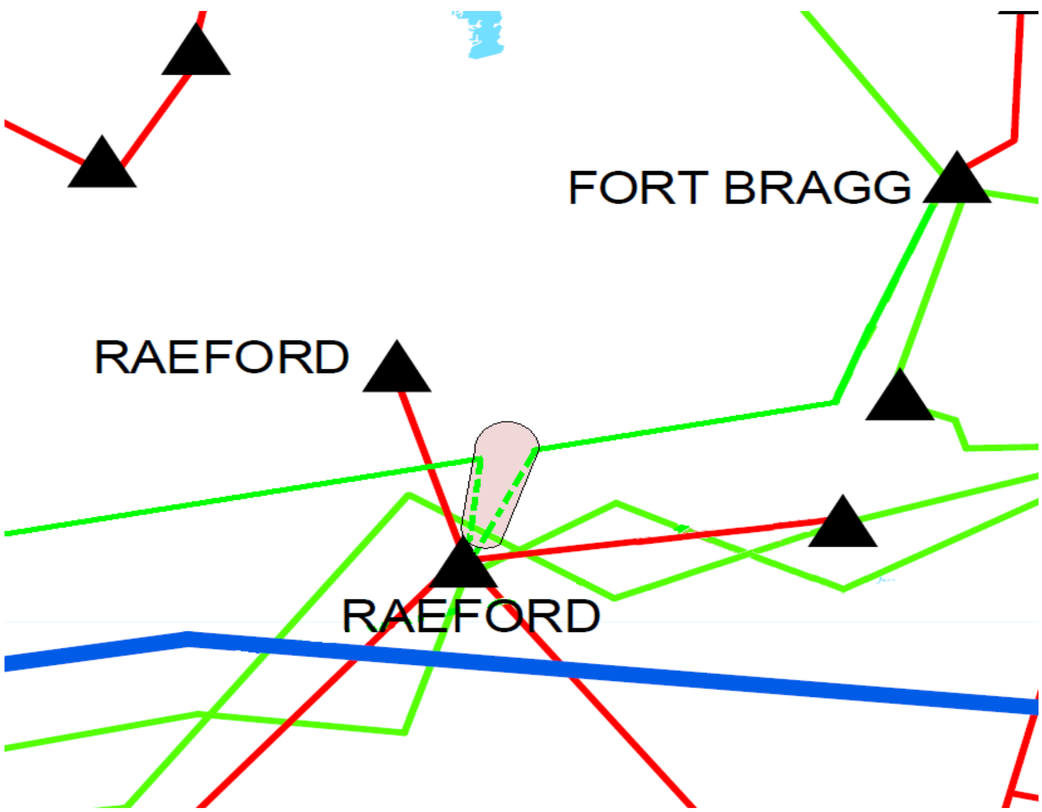
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

Why this Project was Selected as the Preferred Solution
Arabia had a higher cost and did not mitigate other contingencies of concern.

C-3

Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank

- **NERC Category P5 Violation**
- **Problem:** By 2018, with a Brunswick Unit down, loss of the common tower Fayetteville – Rockingham 230 kV and Fayetteville – Raeford 230 kV Lines may cause the Weatherspoon – Raeford 115 kV Line to overload. In addition, by 2018, the N-1-1 contingency of losing both of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation may overload the Laurinburg - Raeford 115 kV Line.
- **Solution:** At the Raeford 230kV Substation, loop-in the Richmond – Ft. Bragg Woodruff St. 230 kV Line and add a 300 MVA transformer**.**



Project ID and Name: 0031 – Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation

Project Description
The project scope consists of constructing a new 230 kV Line from Jacksonville 230 kV to a new 230 kV substation in the Grants Creek area. The 230 kV line shall be constructed with 6-1590 MCM ACSR or equivalent and will convert the existing Jacksonville - Havelock 230 kV Line into Jacksonville - Grants Creek 230 kV Line and Grants Creek - Havelock 230 kV Line. The new 230 kV Grants Creek Substation will be built with 4-230 kV breakers, a new 230/115 kV transformer, and tap into the Jacksonville City - Harmon POD 115 kV Feeder with 1-115 kV breaker.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2020
Estimated Time to Complete	3 years
Estimated Cost	$45 M

Narrative Description of the Need for this Project
The common tower outage of Jacksonville – Havelock 230 kV Line and Jacksonville – Jacksonville City 115 kV Line may cause the voltages in the Camp Lejeune area to fall below the planning criteria. Also, outage of the Jacksonville - New Bern 230 kV Line may cause the Havelock- Jacksonville 230 kV to overload.

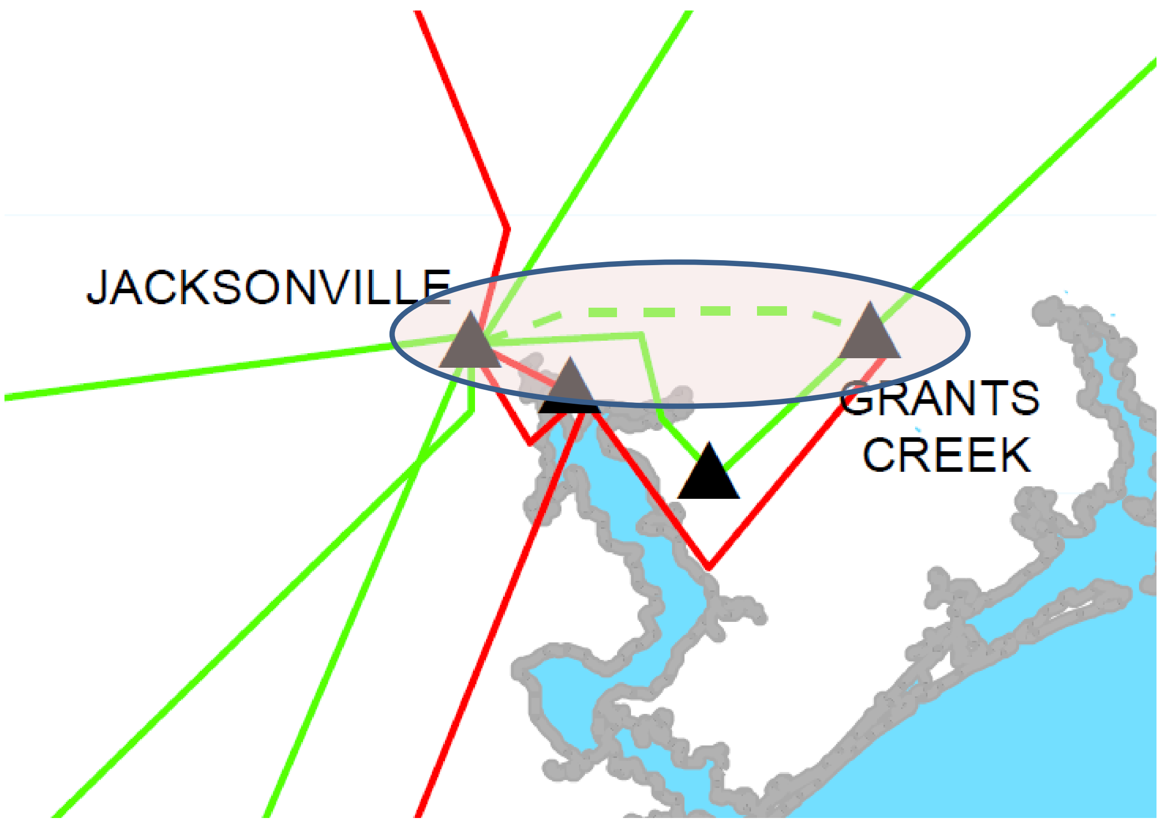
Other Transmission Solutions Considered
Construct 230 kV feeder from Jacksonville to Camp LeJeune Tap.

Why this Project was Selected as the Preferred Solution
The alternate solution was determined to be infeasible due to routing challenges.

C-4

Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation

- **NERC Category P7 violation**
- **Problem:** The common tower outage of Jacksonville – Havelock 230 kV Line and Jacksonville – Jacksonville City 115 kV Line may cause the voltages in the Camp Lejeune area to fall below the planning criteria. Also, outage of the Jacksonville - New Bern 230 kV Line may cause the Havelock - Jacksonville 230 kV Line to overload.
- **Solution:** Construct new 230 kV line and substation.



Project ID and Name: 0032 – Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation

Project Description
Construct new 230kV Switching Station in the Newport Area, construct new 230kV Substation in the Harlowe Area, and construct the Newport Area - Harlowe Area 230kV line comprised of 3-1590 MCM ACSR or equivalent. The Newport Area 230kV Switching Station will initially consist of a 3-breaker ring bus but should be laid out for future development as a standard 230/115 kV substation with breaker-and-a-half configuration in the 230kV yard. The Harlowe Area 230kV Substation will initially consist of one 200 MVA (or 300MVA), 230/115kV transformer and 3-115kV breakers, and should be laid out for future development as a standard 230/115 kV substation with breaker-and-a-half configuration in the 230kV yard.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2020
Estimated Time to Complete	3 years
Estimated Cost	$40 M

Narrative Description of the Need for this Project
By summer 2020, an outage of the Havelock terminal of the Havelock - Morehead Wildwood 115 kV North Line will cause the voltages in the Havelock area to fall below planning criteria. The construction of this new line will mitigate this voltage problem.

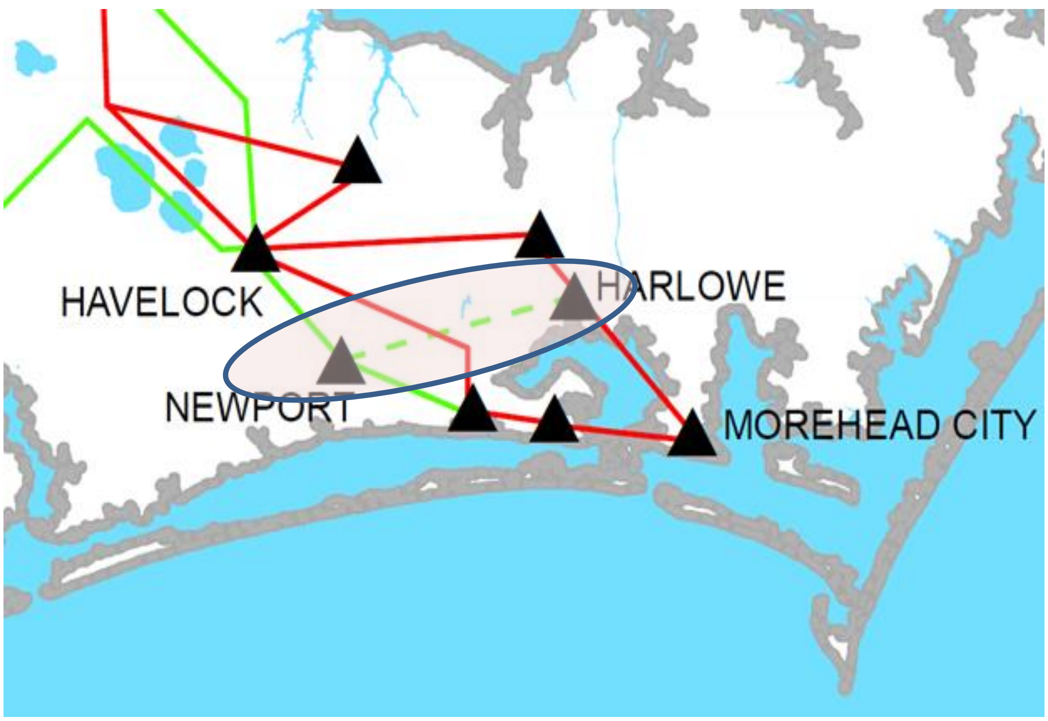
Other Transmission Solutions Considered
Convert Havelock-Morehead Wildwood115 kV North Line to 230 kV.

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

C-5

Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation

- **NERC Category P1 violation**
- **Problem:** By summer 2020, an outage of the Havelock terminal of the Havelock - Morehead Wildwood 115 kV North Line will cause the voltages in the Havelock area to fall below planning criteria. The construction of this new line will mitigate this voltage problem.
- **Solution:** Construct new 230 kV line, switching station and substation.



Project ID and Name: 0033 – Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV Transformer with Two 300 MVA Banks and Reconductor Manchester 115 kV Feeder

Project Description
Replace the existing 150 MVA, 230/115 kV transformer bank (three 1-phase & spare 50 MVA) at the Ft. Bragg Woodruff Street 230kV Substation with two 3-phase 300 MVA, 230/115 kV transformers from Apex US#1 230kV Substation per Equipment Engineering. Two 115 kV circuit breakers with associated disconnect switches will be installed. Also reconductor the Ft. Bragg Woodruff Street - Manchester 115kV Feeder (4.42 miles) with 3-1590 MCM ACSR or equivalent.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	2/24/2017
Estimated Time to Complete	-
Estimated Cost	$18 M

Narrative Description of the Need for this Project
In 2016/17 winter, during peak load conditions, load on the Ft. Bragg Woodruff Street - Manchester 115kV Feeder were projected to exceed the feeder capacity and the transformer bank rating at the Ft. Bragg Woodruff Street 230kV Substation. DEP worked with South River EMC and Central EMC to manage the loading on this feeder for several years and we jointly agreed that this was the best alternative to alleviate these issues.

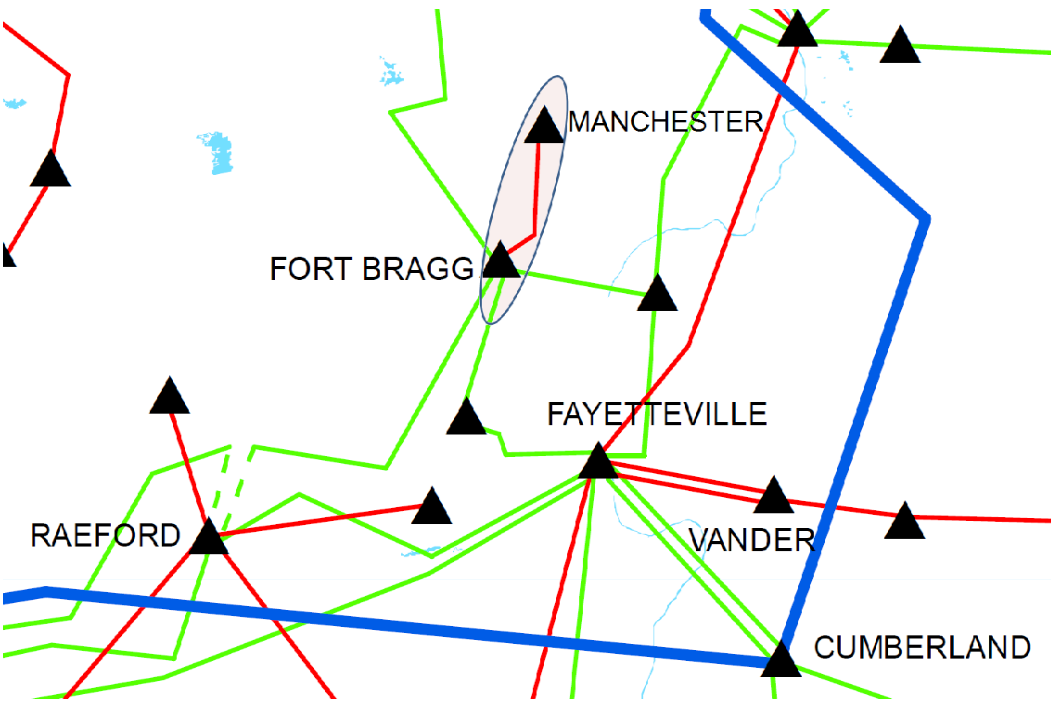
Other Transmission Solutions Considered
Convert 115 kV feeder to 230 kV.

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

C-6

Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV Transformer with Two 300 MVA Banks and Reconductor Manchester 115 kV Feeder

- **NERC Category P1 violation**
- **Problem:** In 2016/17 winter, during peak load conditions, load on the Ft. Bragg Woodruff Street - Manchester 115kV Feeder was projected to exceed the feeder capacity and the transformer bank rating at the Ft. Bragg Woodruff Street 230kV Substation. DEP worked with South River EMC and Central EMC to manage the loading on this feeder for several years and we jointly agreed that this was the best alternative to alleviate these issues.
- **Solution:** Replace transformers, reconductor 115 kV feeder.



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 800A current transformers at both line terminals will have to be uprated as part of this project. The thermal rating of this line will then be limited to 239 MVA due to the 1200 A disconnects at both terminals.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2019
Estimated Time to Complete	2 years
Estimated Cost	$9 M

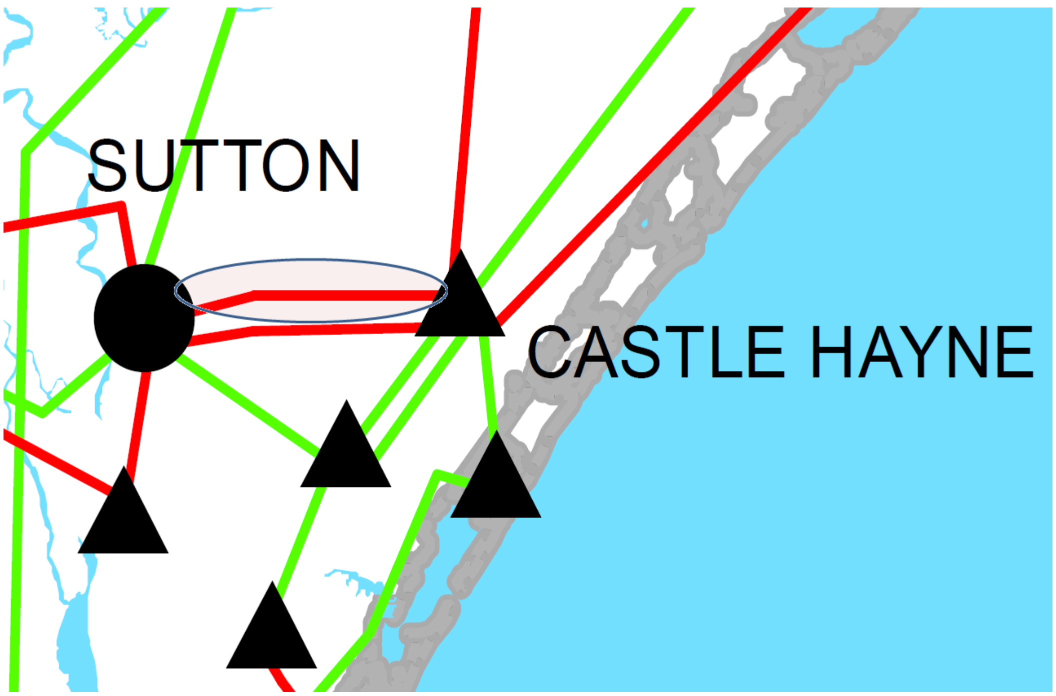
Narrative Description of the Need for this Project
By 2019, with all area generation online, the loss of the Sutton Plant - Castle Hayne 115 kV South Line will cause the Sutton Plant - Castle Hayne 115 kV North Line to exceed its thermal rating.

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

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

Sutton - Castle Hayne 115 kV North Line - Rebuild

- **NERC Category P1 violation**
- **Problem:** By 2019, 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: 0036 – Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank

Project Description
This project consists of upgrading Asheville Plant to interconnect two combined cycle units. The project includes upgrading the existing 230/115 kV transformers to 400 MVA each, reconductoring the 115 kV north and south transformer tie lines, replacing breakers, and adding a 230 kV capacitor bank.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2019
Estimated Time to Complete	2.5 years
Estimated Cost	$30 M

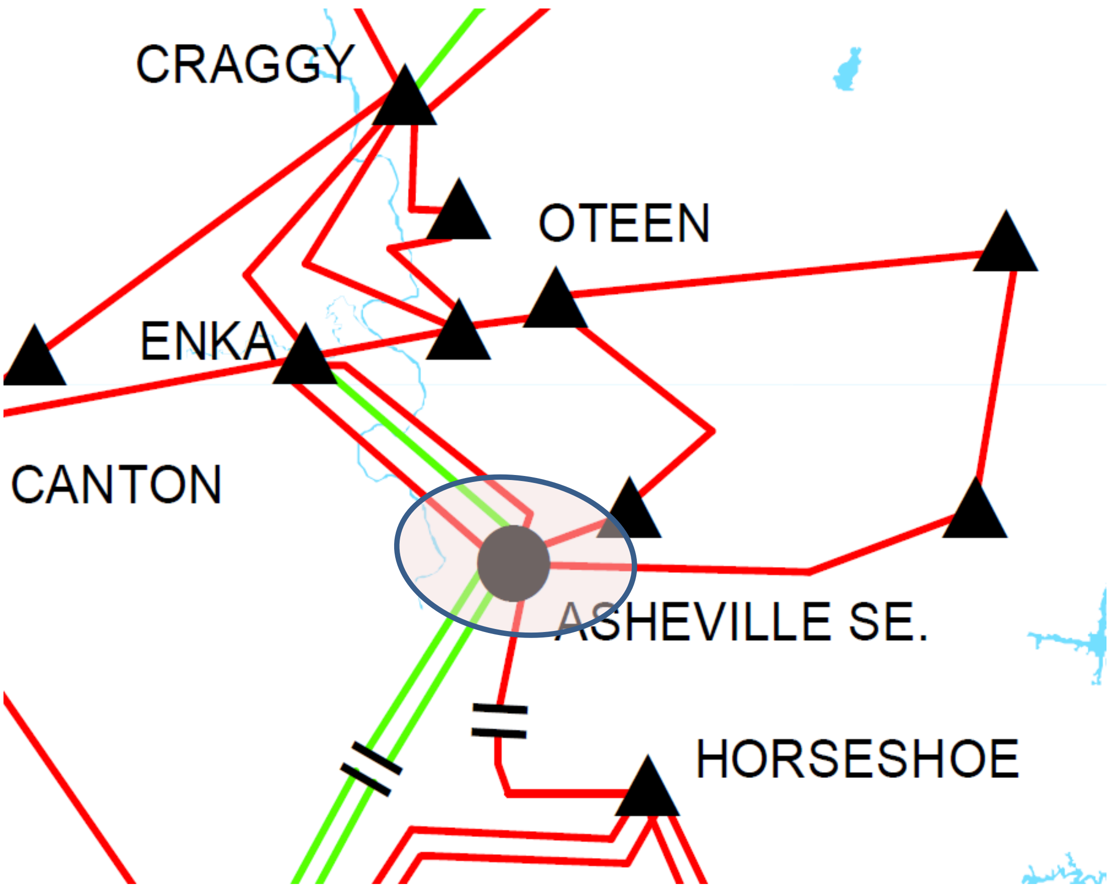
Narrative Description of the Need for this Project
Interconnect two combined cycle units.

Other Transmission Solutions Considered
These are generation interconnection network upgrade facilities without a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank

- **NERC Category P3 violation**
- **Problem:** Interconnect two combined cycle units at Asheville Plant in 2019.
- **Solution:** Upgrade the existing 230/115 kV transformers to 400 MVA each, reconductor the 115 kV north and south transformer tie lines, replace breakers, and add a 230 kV capacitor bank.



Project ID and Name: 0037 – Cane River 230 kV Substation, Construct 150 MVAR SVC

Project Description
This project consists of upgrading Cane River 230 kV Substation by adding a 150 MVAR 230 kV static VAR compensator (SVC).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2019
Estimated Time to Complete	2.5 years
Estimated Cost	$34 M

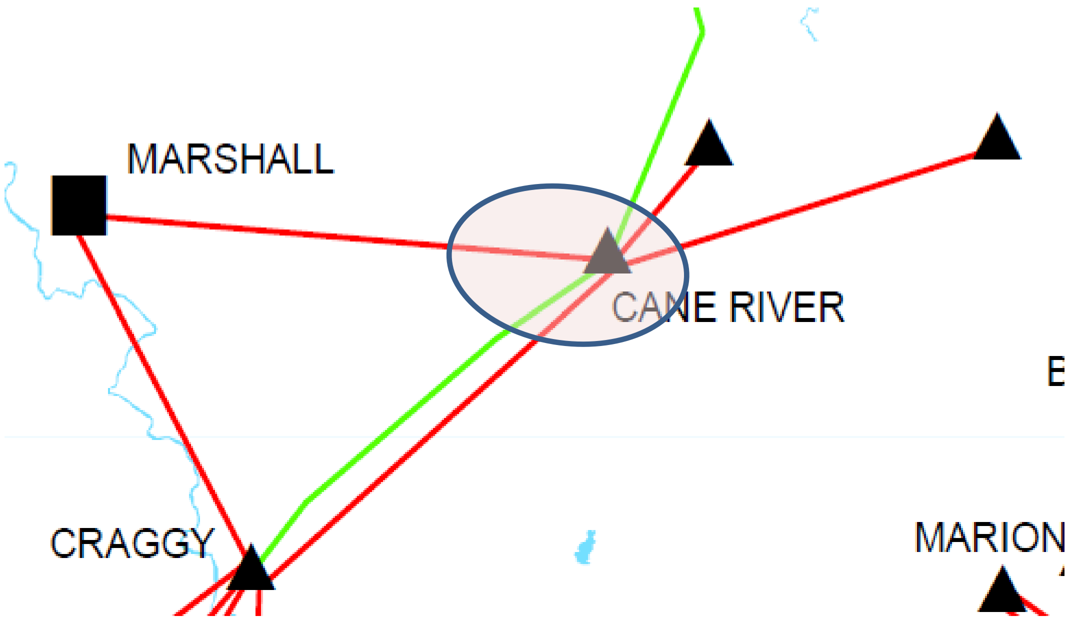
Narrative Description of the Need for this Project
Interconnect two combined cycle units.

Other Transmission Solutions Considered
Considered constructing new interconnections.

Why this Project was Selected as the Preferred Solution
It was determined that constructing new interconnections was not feasible.

Cane River 230 kV Substation, Construct 150 MVAR SVC

- **NERC Category B violation**
- **Problem:** Interconnect two combined cycle units at Asheville Plant in 2019.
- **Solution:** Upgrade the Cane River 230 kV Substation by adding a 150 MVAR 230 kV static VAR compensator (SVC).



Project ID and Name: 0038 –Harley 100 kV Lines (Tiger - Campobello) Reconductor

Project Description
This project consists of rebuilding 11.8 miles of the existing 336 ACSR conductor with 1158 ACSS/TW.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2021
Estimated Time to Complete	3 years
Estimated Cost	$18 M

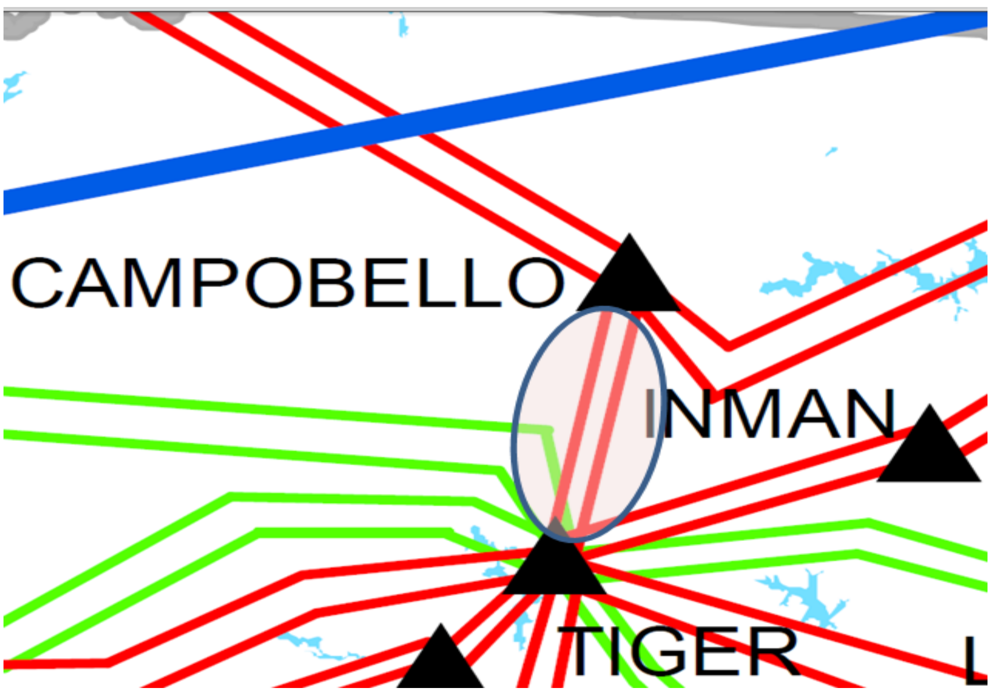
Narrative Description of the Need for this Project
Under high levels of transfer to CPLW, these lines may become overloaded because they are on one of the two 100 kV paths that connect DEC to CPLW.

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.

Harley 100 kV Lines (Tiger - Campobello) Reconductor

- **NERC Category P7 violation**
- **Problem:** The outage of both Pisgah - Shiloh 230 kV lines may overload these lines.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



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

Project Description
This project consists of rebuilding/reconductoring approximately 6.5 miles of the existing 115kV line using 3-1590 or equivalent conductor. This project requires the replacement of disconnect switches at Asheboro 230kV and the replacement of the breaker, the disconnect switches, and the 115 kV east bus at Asheboro East 115kV 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	6/1/2019
Estimated Time to Complete	1.5 years
Estimated Cost	$12 M

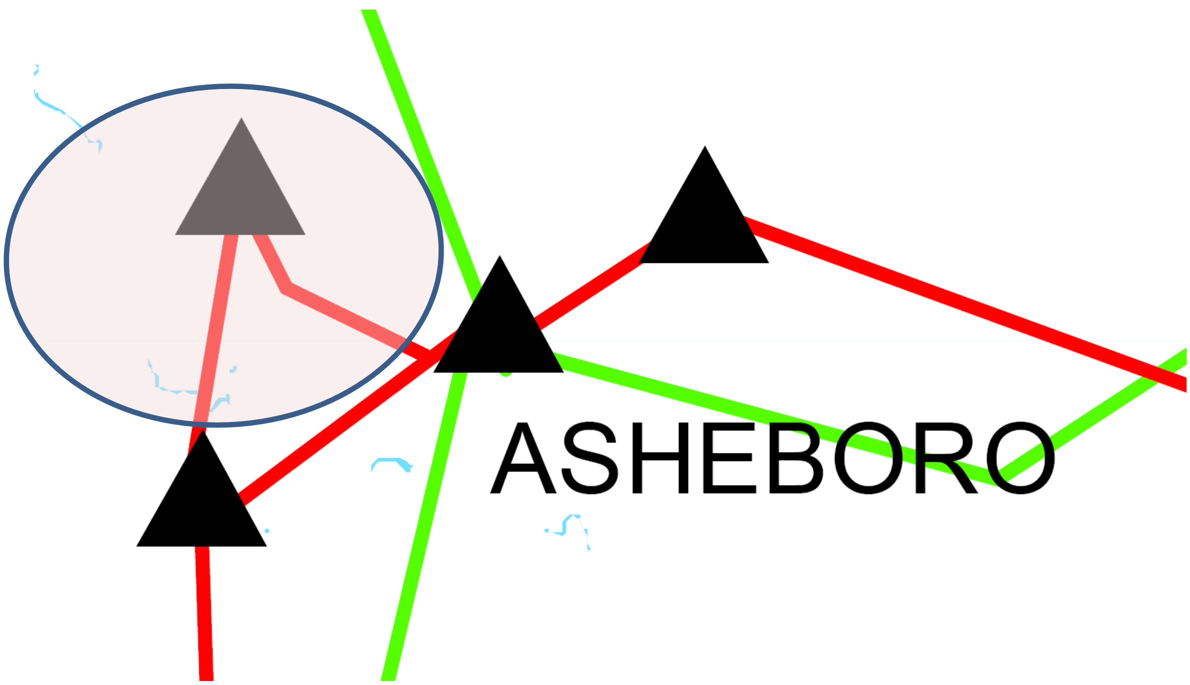
Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Asheboro-Asheboro East 115kV North line under the contingency of losing the Asheboro-Asheboro-East 115kV South line with Harris Plant down.

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

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

Asheboro-Asheboro East 115kV North Line Reconductor

- **NERC Category P3 violation**
- **Problem:** By the summer of 2019, with Harris down, the loss of the Asheboro-Asheboro East 115kV South line will cause the Asheboro-Asheboro East 115kV North line to overload.
- **Solution:** Rebuild/reconductor the Asheboro-Asheboro East 115kV North Line and upgrade equipment.



Project ID and Name: 0040 – Delco 230kV Substation, Convert to Double Breaker

Project Description
This project consists of relocating the Cumberland and Brunswick Plant East 230kV Line Terminals, converting the Sutton Plant 230kV Terminal and Brunswick Plant 230kV West Terminal to a double breaker scheme, and converting the Cumberland 230kV Terminal and Brunswick Plant 230kV East Terminal to a double breaker scheme.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2019
Estimated Time to Complete	1.5 years
Estimated Cost	$13 M

Narrative Description of the Need for this Project
The conversion of the Delco 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event; while maintaining compliance with NERC Transmission Planning Standards.

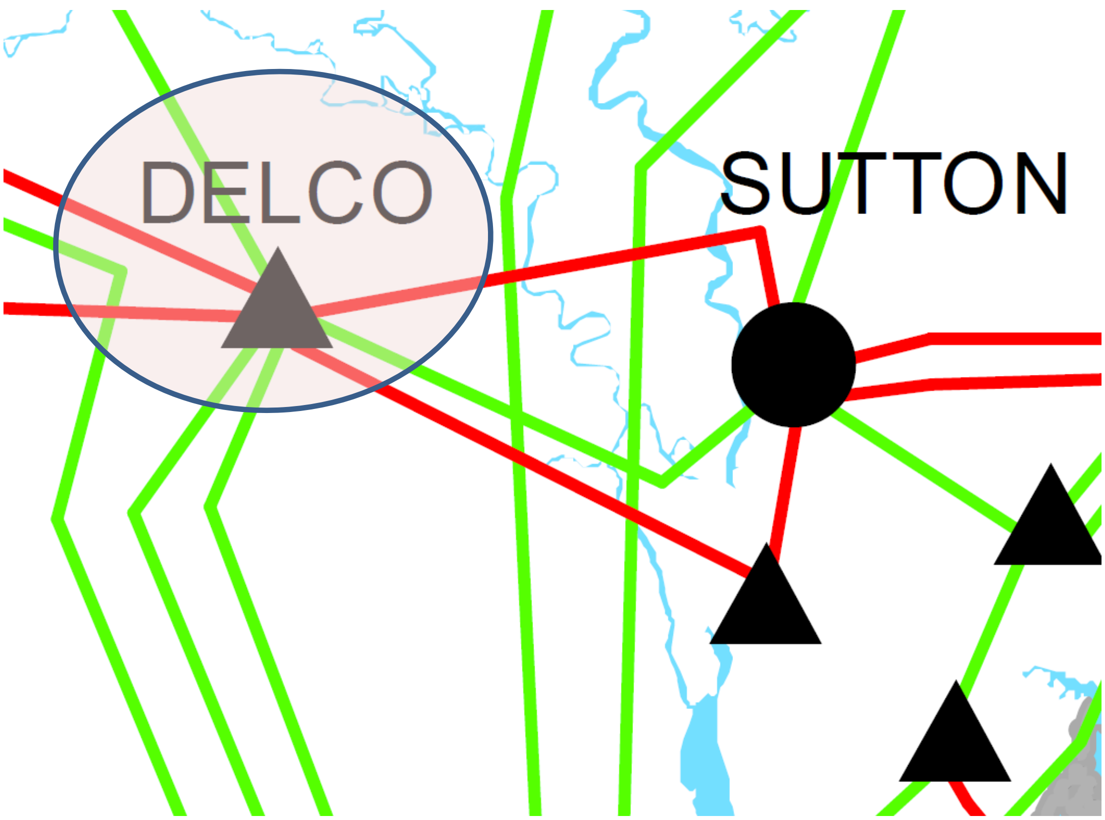
Other Transmission Solutions Considered
There is not a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

C-12

Delco 230kV Substation, Convert to Double Breaker

- **NERC Category P4 violation**
- **Problem:** The conversion of the Delco 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event; while maintaining compliance with NERC Transmission Planning Standards.
- **Solution:** At Delco 230kV Substation, relocate the Cumberland and Brunswick Plant East 230kV Line Terminals. Convert the Sutton Plant 230kV Terminal and Brunswick Plant 230kV West Terminal to a double breaker scheme. Convert the Cumberland 230kV Terminal and Brunswick Plant 230kV East Terminal to a double breaker scheme.



Project ID and Name: 0041 – Castle Hayne 230kV Substation, Convert to Double Breaker

Project Description
This project consists of relocating the Sutton Plant 230kV and Folkstone 230kV Line Terminals, converting the new Folkstone 230kV Terminal and Wilmington Corning 230kV Terminal to a double breaker scheme, and converting the new Sutton Plant 230kV Terminal and Brunswick Plant Unit 1 230kV Terminal to a double breaker scheme.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2019
Estimated Time to Complete	1.5 years
Estimated Cost	$10 M

Narrative Description of the Need for this Project
The conversion of the Castle Hayne 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event, while maintaining compliance with NERC Transmission Planning Standards.

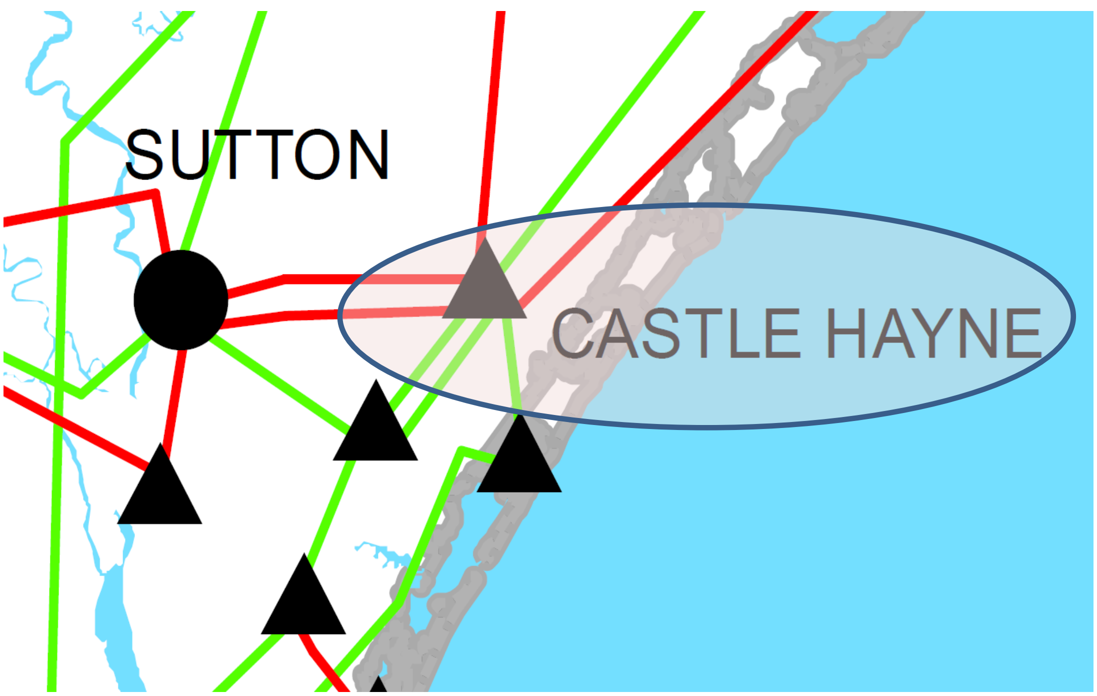
Other Transmission Solutions Considered
There is not a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

C-13

Castle Hayne 230kV Substation, Convert to Double Breaker

- **NERC Category P4 violation**
- **Problem:** The conversion of the Castle Hayne 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event, while maintaining compliance with NERC Transmission Planning Standards.
- **Solution:** At Castle Hayne 230kV Substation, relocate the Sutton Plant 230kV and Folkstone 230kV Line Terminals. Convert the new Folkstone 230kV Terminal and Wilmington Corning 230kV Terminal to a double breaker scheme. Convert the new Sutton Plant 230kV Terminal and Brunswick Plant Unit 1 230kV Terminal to a double breaker scheme.



Project ID and Name: 0042 – Rural Hall 100 kV, Install SVC

Project Description
This project consists of installing a -100/+300 MVAR SVC at Rural Hall 100 kV.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	6/1/2020
Estimated Time to Complete	2 years
Estimated Cost	$50 M

Narrative Description of the Need for this Project
Installation of a SVC at Rural Hall will mitigate voltage concerns driven by certain contingency conditions in DEC.

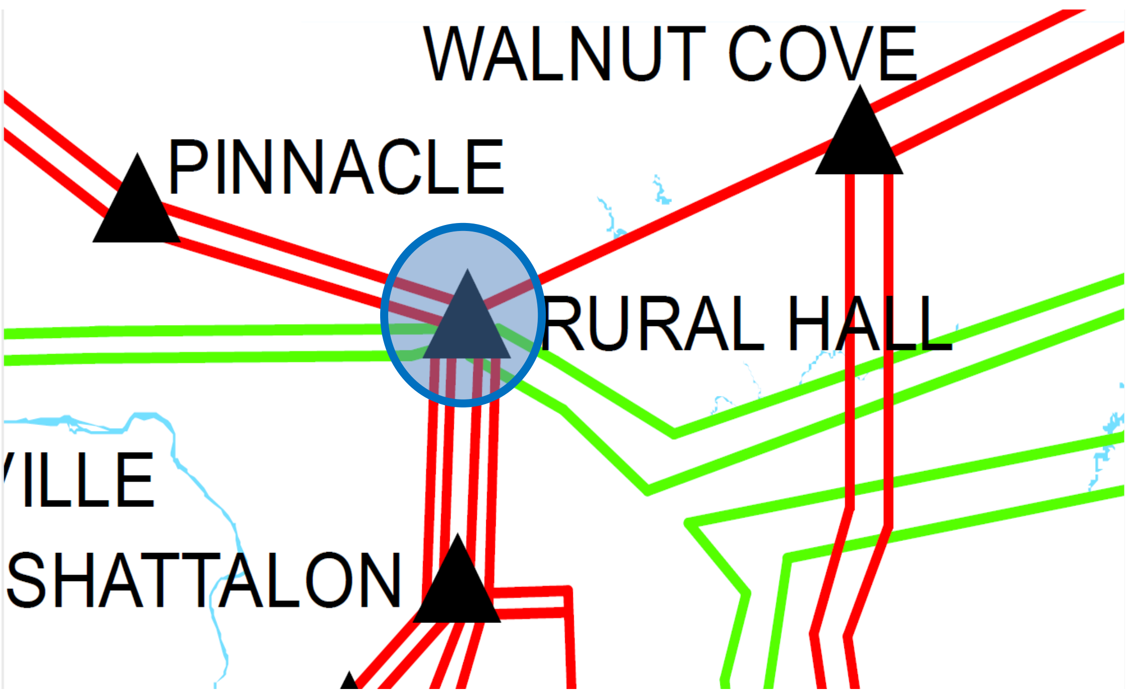
Other Transmission Solutions Considered
New generation.

Why this Project was Selected as the Preferred Solution
Solution can be implemented quicker than new generation and at a lower cost.

C-14

Rural Hall 100 kV, Install SVC

- **Problem:** Under certain conditions, additional voltage support is required in order to maintain system reliability.
- **Solution:** The installation of a SVC at Rural Hall 100 kV will provide voltage support to the region and increase system reliability under certain conditions. As part of the project there will be a reconfiguration of the 100 kV capacitors at Rural Hall.



Project ID and Name: 0043 – 230/100 kV Tie Station, Catawba County, NC

Project Description
This project consists of installing a 230/100 kV tie station in Catawba County, NC.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2021
Estimated Time to Complete	2.5 years
Estimated Cost	$45 M

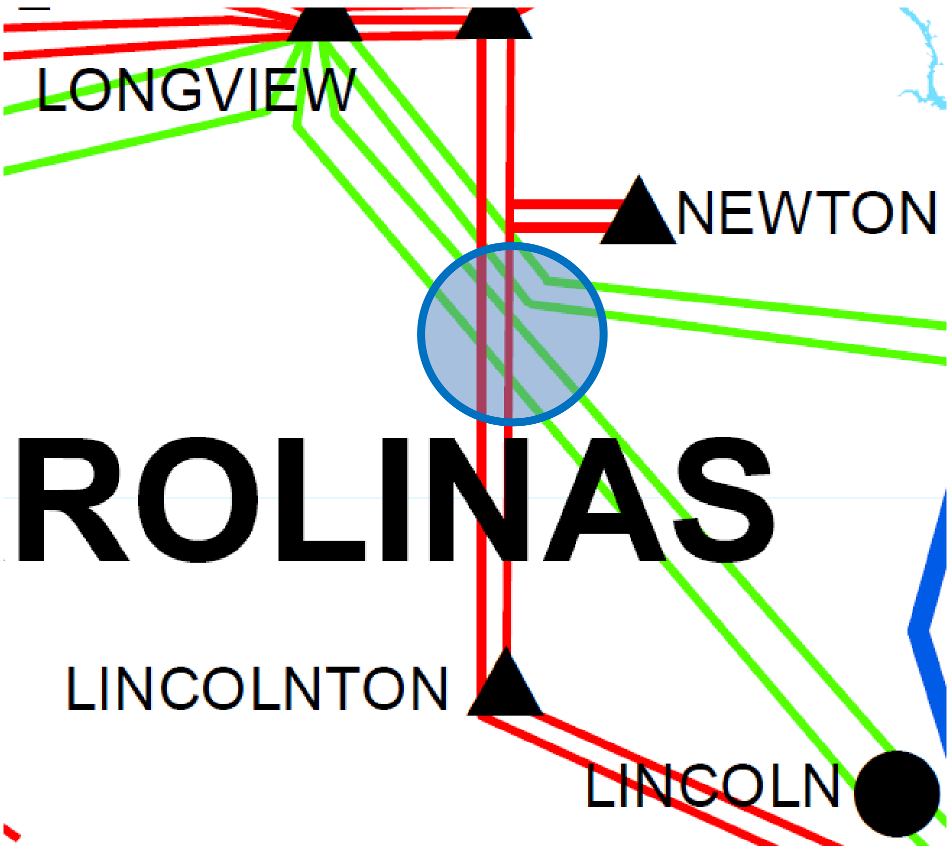
Narrative Description of the Need for this Project
The installation of this new 230/100 kV tie station will provide greater ability to meet local load growth and maintain compliance with NERC Transmission Planning Standards.

Other Transmission Solutions Considered
Upgrade ≈30 miles of 100 kV.

Why this Project was Selected as the Preferred Solution
Ability to meet local load growth.

230/100 kV Tie Station, Catawba County, NC

- **Problem:** Existing transmission lines are not sufficient to meet local load growth.
- **Solution:** Fold-in existing 230 kV and 100 kV lines to new station. Add sufficient transformation between 230 kV and 100 kV.



Project ID and Name: 0044 –Reidsville 100 kV Lines (Dan River-Sadler) Reconductor

Project Description
This project consists of rebuilding ≈8 miles of the existing 336 ACSR conductor.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	3 years
Estimated Cost	$13 M

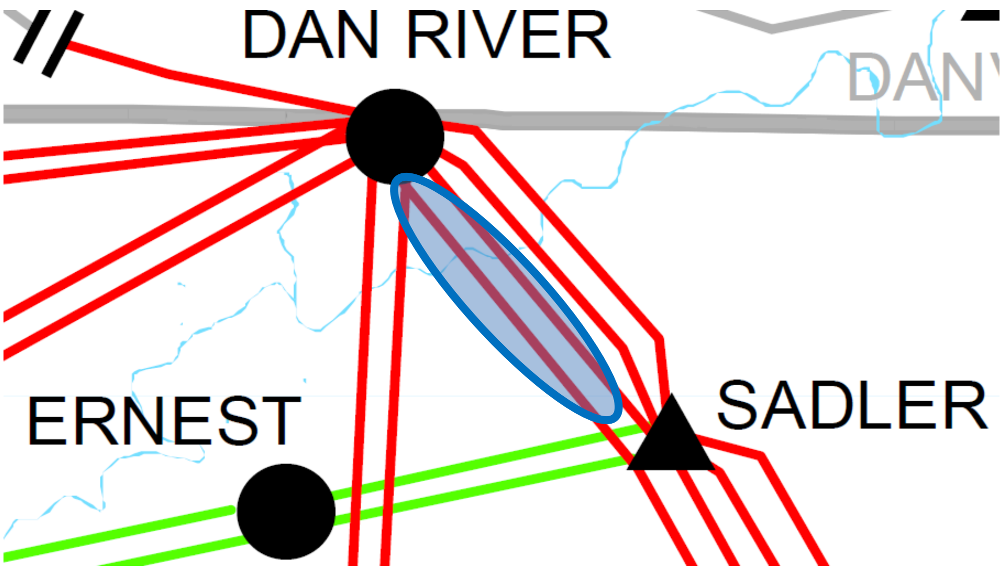
Narrative Description of the Need for this Project
These 100 kV lines can become overloaded for the loss of the parallel circuit.

Other Transmission Solutions Considered
New 100 kV transmission line parallel to existing transmission lines.

Why this Project was Selected as the Preferred Solution
New right-of-way not required. Increased thermal capacity.

Reidsville 100 kV Lines (Dan River-Sadler) Reconductor

- **NERC Category P3 violation**
- **Problem:** Loss of the parallel circuit will overload the remaining circuit.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



Project ID and Name: 0045 –Wolf Creek 100 kV Lines (Dan River-Sadler) Reconductor

Project Description
This project consists of rebuilding ≈8 miles of the existing 336 ACSR conductor.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	3 years
Estimated Cost	$13 M

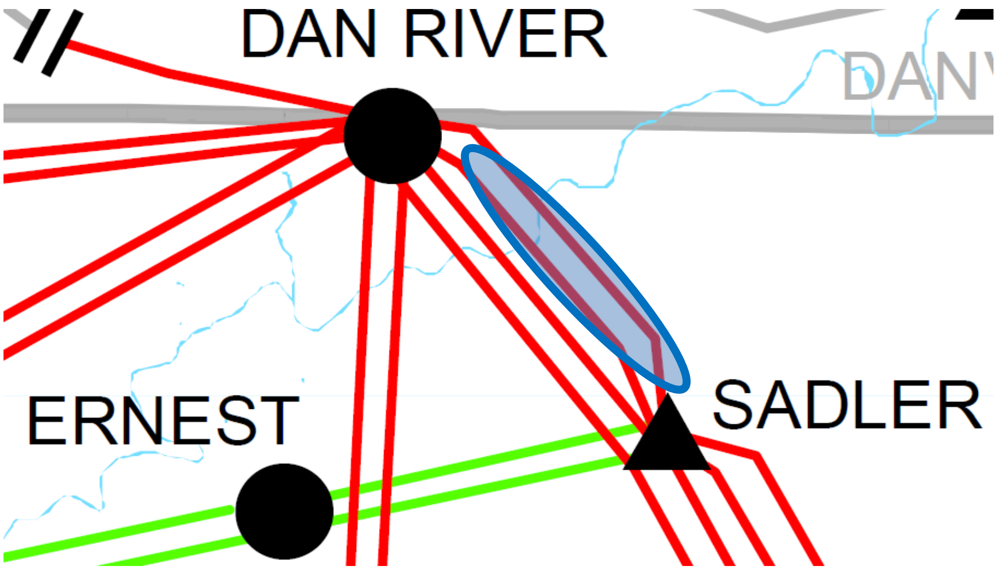
Narrative Description of the Need for this Project
These 100 kV lines can become overloaded for the loss of the parallel circuit.

Other Transmission Solutions Considered
New 100 kV transmission line parallel to existing transmission lines.

Why this Project was Selected as the Preferred Solution
New right-of-way not required. Increased thermal capacity.

Reidsville 100 kV Lines (Dan River-Sadler) Reconductor

- **NERC Category P3 violation**
- **Problem:** Loss of the parallel circuit will overload the remaining circuit.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



Appendix D
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
			2016 Plan[1]			2017 Plan			
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	
0024	Durham - RTP 230 kV Line, Reconductor	DEP	Planned	6/1/2024	15	Planned	TBD	15	
0028	Brunswick #1 – Jacksonville 230 kV Line Loop into Folkstone 230 kV Substation	DEP	Planned	6/1/2024	14	Planned	6/1/2024	14	
0030	Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank	DEP	Planned	6/1/2018	16	Planned	6/1/2018	20	
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	DEP	Planned	6/1/2020	31	Planned	6/1/2020	51	

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)								
			2016 Plan[1]			2017 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	DEP	Planned	6/1/2020	30	Planned	6/1/2020	40
0033	Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV Transformer with Two 300 MVA Banks & Reconductor Manchester 115 kV Feeder	DEP	Underway	6/1/2016	19	In-Service	2/24/2017	19
0034	Sutton - Castle Hayne 115 kV North Line - Rebuild	DEP	Planned	6/1/2018	9	Underway	6/1/2019	11

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
			2016 Plan[1]			2017 Plan			
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	
0036	Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank	DEP	Planned	12/1/2019	30	Planned	12/1/2019	40	
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	DEP	Planned	12/1/2019	30	Planned	12/1/2019	42	
0038	Harley 100 kV Lines (Tiger - Campobello) Reconductor	DEC	Planned	6/1/2021	20	Planned	12/1/2020	18	
0039	Asheboro-Asheboro East 115kV North Line Reconductor	DEP	-	-	-	Underway	6/1/2019	12	
0040	Delco 230kV Substation, Convert to Double Breaker	DEP	-	-	-	Underway	6/1/2019	13	

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
			2016 Plan[1]			2017 Plan			
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0041	Castle Hayne 230kV Substation, Convert to Double Breaker	DEP	-	-	-	Underway	6/1/2019	10
0042	Rural Hall 100 kV, Install SVC	DEC	-	-	-	Planned	6/1/2020	50
0043	230/100 kV Tie Station, Catawba County NC	DEC	-	-	-	Planned	12/1/2021	45
0044	Reidsville 100 kV Lines (Dan River-Sadler) Reconductor	DEC	-	-	-	Conceptual	TBD	13
0045	Wolf Creek 100 kV Lines (Dan River-Sadler) Reconductor	DEC	-	-	-	Conceptual	TBD	13
TOTAL					**214**			**426**

[1] Information reported in Appendix B of the NCTPC 2016 - 2026 Collaborative Transmission Plan" dated January 13, 2017.

[2] Status: *In-service:* Projects with this status are in-service.

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 2016 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2017 Collaborative Transmission 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
ISA	Interconnection Service Agreement
kV	Kilovolt
LGIA	Large Generator Interconnection Agreement
LSE	Load Serving Entity
LTSG	SERC Long-Term Study 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
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
PSS/E	Power System Simulator for Engineering
PWG	Planning Working Group
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