North Carolina Transmission Planning Collaborative

Report on the NCTPC 2016-2026 Collaborative Transmission Plan

December 8, 2016
DRAFT Report

2016 – 2026 NCTPC Transmission Plan
Table of Contents

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 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, whose studies 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 2015-2025 Collaborative Transmission Plan (the "2015 Collaborative Transmission Plan" or the "2015 Plan") was published in January 2016.

This report documents the current 2016 – 2026 Collaborative Transmission Plan ("2016 Collaborative Transmission Plan" or the "2016 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2016 reliability planning study scope and methodology. The NCTPC Process document and 2016 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2016 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 2016 through 2026 with the Participants' planned Designated Network Resources ("DNRs").

The 2016 Study[1] model included the following modelling assumptions related to the Western Carolinas Modernization Project ("WCMP"):

- Asheville 1 and 2 coal units will be shut down in all three study cases.
- Two planned Asheville combined cycle (CC) units (280 MW each, 560 MW total winter rating) will be added to all three study cases.
- One of the planned Asheville CC units will be connected to the Asheville 230 kV switchyard and the other will be connected to the Asheville 115 kV switchyard.
- Both the summer and winter cases will include a CPLW import of 436 MW.
- The 436 MW import into CPLW will come from the following sources: 400 MW from CPLE, 22 MW from SCPSA, and 14 MW from TVA. To meet the remaining CPLW load, CPLW generation will be dispatched in the following order: Walters, Marshall, planned Asheville CC units, and finally the existing Asheville CTs.
- While the final System Impact Study for the planned Asheville CC units was not yet completed, DEP was confident of two required upgrades: replacing the Asheville 230/115 kV and Pisgah 115/100 kV autotransformers with larger

[1] The term "2016 Study" is a generic term referring to all the study work that was done in 2016 which includes the reliability analysis as well the additional stress tests to the transmission systems of Duke Energy Carolinas and Duke Energy Progress as a part of the Reliability Planning Process.

units; therefore, these transformer upgrades were modeled in the 2016 study.

Based on the study's input assumptions, the 2016 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2016 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 2015 Plan continue to satisfactorily address the reliability concerns identified in the 2016 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2016 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

The 2016 Plan includes ten 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 ten reliability projects in the 2016 Plan is $214 million. This compares to the original 2015 Plan estimate of $156 million for eight 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 E for a detailed comparison of this year's Plan to the 2015 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 2016 Plan.

The modified projects for DEP and DEC in the 2016 Plan, relative to the 2015 Plan, include two new DEP projects, one new DEC project and one DEC project that was placed in service. The project placed in service was:

- Reconductor Norman 230 kV Lines (McGuire - Riverbend)

The two new DEP projects in the 2016 Plan are:

- 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
- Cane River 230 kV Substation, Construct 150 MVAR SVC

The new DEC project in the 2016 Plan is:

- Reconductor Harley 100kV lines (Tiger – Campobello)

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

- Raeford 230 kV substation, project to loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and add 3rd 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.
- 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 had an increase in estimated cost.
- Sutton - Castle Hayne 115 kV North line Rebuild had a decrease in estimated cost.

No Local Economic Study or Public Policy Study requests were received from TAG stakeholders by February 1 for the 2016 study year. Therefore, there will be no Local Economic Study Planning Process nor evaluations of Public Policy impacts as a part of the 2016 NCTPC Study.

This year the NCTPC did perform several additional sensitivities as additional stress tests to the transmission systems of DEC and DEP as a part of the Reliability Planning

Process. These additional sensitivities included the following:

- For a hypothetical event resulting in a long-term outage of an entire nuclear power plant, evaluate the simultaneous outage of both nuclear units at the Brunswick Nuclear Plant in the Wilmington area of the DEP system. Replacement power for the Brunswick Units will be modeled as coming from neighboring systems.

- Identify permanent transmission upgrades that would eliminate the use of specific operating procedures currently in effect on the DEC and DEP systems for mitigating reliability violations under peak operating conditions. The final set of operating procedures that were evaluated in this study are listed in Table 1 below.

Table 1
Operating Procedures Evaluated in the 2016 Study

Guide	Action	Limiting Facility	Outaged Facilities
DEC/DEP	Open Wateree 115/100 kV	Wateree - Great Falls 100 kV 1/2	Wateree - Great Falls 100 kV 2/1
		Camden – Industry 104 115 kV Line	Camden - Camden Junction 115 kV Line with Harris offline
DEP	Open Rockingham - West End 230kV West line at West End	Rockingham-West End 230kV West line	Rockingham - West End 230kV East line with Harris offline
DEP	Open Marion - Weatherspoon 115 kV	Marion-Dillon Tap 115 kV	Latta - Dillon Maple 230 kV with a Brunswick 1 offline

A summary of the additional sensitivity results are provided in Appendix D.

In this 2016 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 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 overall NCTPC Process is performed annually and includes the Reliability Planning and Local Economic Study Processes, whose studies 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 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.

The 2016 NCTPC Process includes several additional sensitivities as part of the Reliability Planning Process and are described in section II.FE below.

II.C. Resource Supply Options Process

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.

No resource supply options were evaluated as a part of the 2016 study.

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 transmission planning process. The Local Economic Study Process provides the means to evaluate the impact of potential supply resources inside and outside the Balancing Authority Areas 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.

The 2016 NCTPC Process contains no Local Economic Study Planning Process as no Local Economic Study requests were received from stakeholders by February 1, 2016. Local Economic Study Process scenarios will be solicited again for the 2017 Study and included if appropriate.

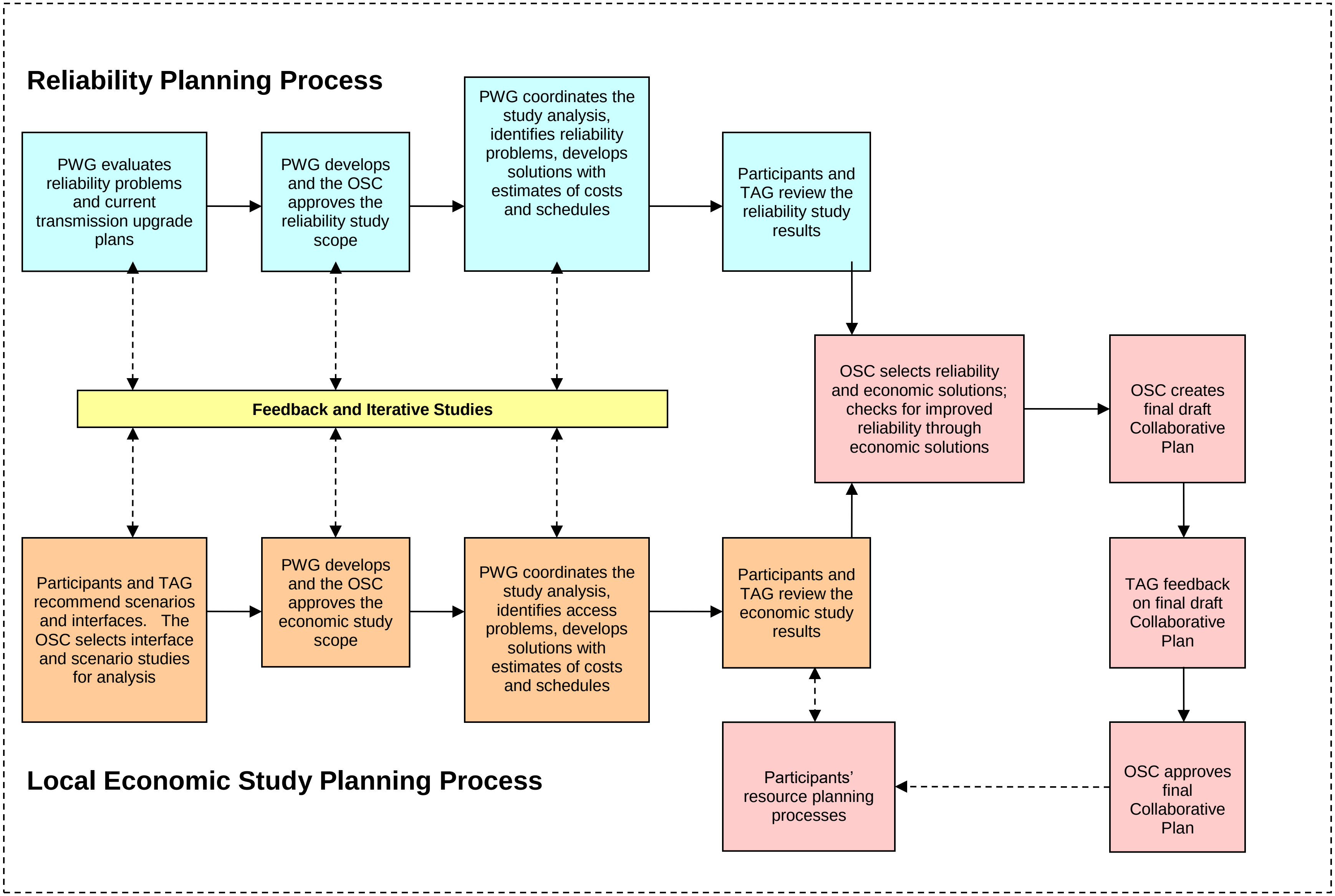
II.E. Local Public Policy Process

The Local Public Policy Process 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 criteria for determining if public policy drives a local transmission need is 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 2016 NCTPC Process contains no evaluations of Local Public Policy impacts as no Local Public Policy requests were received from stakeholders by February 1, 2016. Local Public Policy requests will be solicited again for the 2017 Study and included if appropriate.

2016 NCTPC Process Flow Chart



II.F. Additional Sensitivities Study Process

This year the NCTPC did perform several additional sensitivities as additional stress tests to the transmission systems of DEC and DEP as a part of the Reliability Planning Process. These additional sensitivities included the following:

- For a hypothetical event resulting in a long-term outage of an entire nuclear power plant, evaluate the simultaneous outage of both nuclear units at the Brunswick Nuclear Plant in the Wilmington area of the DEP system. Replacement power for the Brunswick Units will be modeled as coming from neighboring systems.

- Identify permanent transmission upgrades that would eliminate the use of specific operating procedures currently in effect on the DEC and DEP systems for mitigating reliability violations under peak operating conditions. The five original operating procedures that were evaluated in this study are listed in Table 2 below.

Table 2
Operating Procedures Considered in 2016 Study

Guide	Action	Limiting Facility	Outaged Facilities
DEC/DEP	Open Wateree 115/100 kV	Wateree - Great Falls 100 kV ½	Wateree - Great Falls 100 kV 2/1
		Camden – Industry 104 115 kV Line	Camden - Camden Junction 115 kV Line with Harris offline
DEP	Open Rockingham - West End 230kV West line at West End	Rockingham - West End 230kV West line	Rockingham - West End 230kV East line with Harris offline
DEP	Open Marion - Weatherspoon 115 kV	Marion-Dillon Tap 115 kV	Latta - Dillon Maple 230 kV with a Brunswick 1 offline

Guide	Action	Limiting Facility	Outaged Facilities
DEP	Open Weatherspoon - LOF 115 kV line between Pembroke and Maxton	Weatherspoon - LOF 115 kV line	Weatherspoon - Laurinburg 230 kV line with a Brunswick Unit off
DEP	Open Goldsboro Terminal	Goldsboro – E13 Arba 115 kV Line	Wommack – Industry 053 230 kV Line

After the analysis was initiated the following two operating procedures were eliminated:

- Open Weatherspoon-LOF 115 kV line between Pembroke and Maxton – recent revisions to area load forecasting have delayed the need for this operating procedure to be implemented until 2022. DEP has recently added a project to reconductor the LOF-Maxton segment of this line in 2022. The project is not listed in Appendix B because it has been estimated at below $10M.

- Open Goldsboro terminal of Goldsboro-E13 Arba 115 kV line – the loading issue associated with this operating procedure was not observed during analysis. DEP will continue to monitor the loading on this line in future reliability studies.

II.G. 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. 2016 Reliability Planning Study Scope and Methodology

The scope of the 2016 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 2016 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 (280 MW each, 560 MW total winter rating) will be added to all three study cases. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2021 summer through 2026 summer with the Participants' planned Designated Network Resources ("DNRs"). The 2016 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2016 Study also allowed for adjustments to existing plans where necessary. This year the NCTPC also performed several additional sensitivities as discussed by the NCTPC Participants as additional stress tests to the transmission systems of DEC and DEP as a part of the Reliability Planning Process. These additional sensitivities are described in the case development section.

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 Balancing Authority Areas of the Transmission Providers. In 2016, no Local Economic Study requests were received from TAG stakeholders therefore no Local Economic Study Planning Process 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 2016, with the additional sensitivities included as part of the Reliability Planning Process, then no resource supply options were evaluated.

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 2016 Plan addressed a ten-year planning horizon through 2026. The study years chosen for the 2016 Study are listed in Table 4.

Table 4

Study Years

Study Year / Season	Analysis
2021 Summer	Near-term base reliability, additional sensitivities
2021/2022 Winter	Near-term base reliability, additional sensitivities
2026 Summer	Long-term base reliability, additional sensitivities

To identify projects required in years other than the base study years of 2021 and 2026, 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 Balancing Authority Area'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	1.4 % per year
DEP	1.4 % per year

2. Network Modeling

The network models developed for the 2016 Study included new transmission facilities and upgrades for the 2021 and 2026 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2015 Plan. Table 6 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2021 and 2026 models. Table 7 lists the generation facility changes included in the 2021 and 2026 models.

Table 6
Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2021	2026
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

Company	Transmission Facility	2021	2026
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
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
DEC	Reconductored Norman 230 kV Line from McGuire to Riverbend	Yes	Yes

Table 7

Major Generation Facility Changes in Models

Company	Generation Facility	2021	2026
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 Balancing Authority Areas. Generation was dispatched for each Participant to meet that Participant's load in accordance with the designated dispatch order.

Interchange in the base cases was set according to the DNRs identified outside the DEC and DEP Balancing Authority Areas. 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 cases included a CPLW import of 436 MW and the winter case included a CPLW import of 436 MW. The 436 MW import into CPLW will come from the following: 400 MW from CPLE, 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. While the System Impact Study for the planned Asheville CC units is not yet complete, DEP is confident of 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.

---

[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 designated network resources and TRM. DEP calls this maximum transfer case its TRM case.

III.C. Case Development

The base case for the base reliability study was developed using the most current 2015 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.

Additional cases were developed to evaluate additional sensitivities to be performed as a part of Reliability Planning Process. These sensitivities will include the following:

- For a hypothetical event resulting in a long-term outage of an entire nuclear power plant, evaluate the simultaneous outage of both nuclear units at the Brunswick Nuclear Plant in the Wilmington area of the DEP system. Replacement power for the Brunswick Units will be modeled as coming from neighboring systems.

- Identify permanent transmission upgrades that would eliminate the use of specific operating procedures currently in effect on the DEC and DEP systems for mitigating reliability violations under peak operating conditions. The potential upgrade projects are listed in Section V, Table 10.

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 Balancing Authority Area in its base case. Included in this is TRM for use by all LSEs. TRM is composed of contracted VACAR reserve sharing, inrush impacts and parallel path flow 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 2021 and 2026 summer peak base cases with a Brunswick 1 unit outage, a Harris 1 unit outage, or a Robinson 2 unit outage, and from the 2021/2022 winter peak case with 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 2016 Study were also discussed with all Participants so that all are aware of potential issues. Appropriate solutions were jointly 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 2016 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 2015 Study. The PWG participated in the development 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 Balancing Authority Areas, 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 2016, 2020, and 2021 summer timeframes. The limiting facilities identified in the PWG study of base reliability and of the local economic study options 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

As a result of the reliability studies performed on the base cases, DEC has included one new project and DEP has included two new projects in the 2016 Plan relative to the 2015 Plan. With the exception of the aforementioned projects, the 2016 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.

The 2016 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 2016 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 ten reliability projects included in the 2016 Plan is $214 million as documented in Appendix B. This compares to the 2015 Plan estimate of $156 million for eight 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 E for a detailed comparison of this year's Plan to the 2015 Plan.

Appendix C provides a more detailed description of each project in the 2016 Plan.

V. Additional Sensitivities Study Results

At the request of NCEMC, two sensitivity studies were performed using the 2026 summer peak case.

The first study involved taking both units at Brunswick down. SOCO and PJM each provided 980MW of replacement power. The PJM contribution was split evenly between DVP and AEP.

Loading issues observed were mostly already mitigated by operating procedures and future projects or were beyond the 10-year planning horizon. Two loading issues were observed as shown in the following table:

Table 9

Loading Issues Observed in 2016 First Sensitivity Study

Limiting Facility	Outaged Facilities
Marion - Mullins 115kV	Whiteville 230/115kV transformer with Harris down
Shaw AFB-SCEG Eastover 115kV	Common tower outage of the Sumter - SCEG Wateree 230kV line and Sumter - SCEG St. George 230kV with Robinson 2 down

The loading issues identified above would not require any new projects to be built to solve these issues identified as a result of this first sensitivity study.

The second study involved identifying potential projects that would mitigate the need for using certain operating procedures. The potential projects to eliminate the operating procedures evaluated in the 2016 study are shown in the following table:

Table 10

Potential Projects to Eliminate Operating Procedures Evaluated in the 2016 Study

Guide	Potential Project	Limiting Facility	Outaged Facilities
DEC/DEP	Install series reactors in Wateree -Great Falls 100 kV B&W lines	Wateree - Great Falls 100 kV 1/2	Wateree - Great Falls 100 kV 2/1
		Camden - Industry 104 115kV Line	Camden - Camden Junction 115kV line with Harris offline
DEP	Reconductor 7.96 miles of the Rockingham - West End 230 kV West	Rockingham - West End 230kV West line	Rockingham - West End 230kV East line with Harris offline
DEP	Reconductor 14.6 miles of Marion -Dillon Tap 115 kV	Marion-Dillon Tap 115 kV	Latta - Dillon Maple 230 kV with a Brunswick 1 offline

Duke Energy will continue to monitor the loadings on these lines in future reliability studies. These identified projects are not required by the NERC TPL standards and are currently not deemed to be justified based on reliability and cost. A summary of the thermal results for both sensitivities is provided in Appendix D.

VI. Collaborative Transmission Plan

The 2016 Plan includes ten 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 ten reliability projects in the 2016 Plan is $214 million. This compares to the original 2015 Plan estimate of $156 million for eight 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 E for a detailed comparison of this year's Plan to the 2015 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 2016 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. *Deferred* – Projects with this status were identified in the 2015 Report and have been deferred beyond the end of the planning horizon based on the 2016 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

2021 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	11	11
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (PMPA)	113	113
SCPSA (Seneca)	31	31
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (EU)	187	187
SOCO (NCEMC)	0	0
Total	**614**	**614**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	150	150
CPLE (DEP TRM)	0	773
CPLW (Rowan)	0	0
CPLW (DEP TRM)	0	0
DVP (NCEMC)	100	100
Total	**1305**	**2078**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	691	**1464**

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

2021 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	**DEP TRM**
AEP (NCEMC)	100	100
AEP (DEP TRM)	0	100
DEC (Broad River)	850	850
DEC (NCEMC/Catawba)	205	205
DEC (Rowan)	150	150
DEC (DEP TRM)	0	773
DVP (SEPA-KERR)	95	95
DVP (DEP TRM)	0	427
SCEG (DEP TRM)	0	200
SCPSA (DEP TRM)	0	326
Total	**1400**	**3226**

Duke Energy Progress (East) Modeled Exports – MW

	Base	**DEP TRM**
CPLW (Transfer)	400	400
DEC (NCEMC)	11	11
PJM (Ingenco)	6	6
PJM (NCEMC)	330	330
Total	**747**	**747**

Duke Energy Progress (East) Net Interchange - MW

	Base	**DEP TRM**
	-653	**-2479**

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

2021 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	**DEP TRM**
AEP (TRM)	0	0
CPLE (Transfer)	400	400
DUK (Rowan)	0	0
DUK (DEP TRM)	0	0
SCPSA (Waynesville)	22	22
TVA (SEPA)	14	14
TVA (TRM)	0	0
Total	**436**	**436**

Duke Energy Progress (West) Modeled Exports – MW

	Base	**DEP TRM**
---	---	---
Total	**---**	**---**

Duke Energy Progress (West) Net Interchange – MW

	Base	**DEP TRM**
	-436	**-436**

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

2021/2022 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	0	0
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (PMPA)	38	38
SCPSA (Seneca)	26	26
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (EU)	71	71
SOCO (NCEMC)	0	0
Total	**407**	**407**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	0	0
CPLE (DEP TRM)	0	0
CPLW (Rowan)	0	0
CPLW (DEP TRM)	0	135
DVP (NCEMC)	100	100
Total	**1155**	**1290**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	748	**883**

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

2021/2022 WINTER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	DEP TRM
AEP (NCEMC)	100	100
AEP (DEP TRM)	0	0
DEC (Broad River)	850	850
DEC (NCEMC/Catawba)	205	205
DEC (Rowan)	0	0
DEC (DEP TRM)	0	0
DVP (SEPA-KERR)	95	95
DVP (DEP TRM)	0	0
SCEG (DEP TRM)	0	0
SCPSA (DEP TRM)	0	0
Total	**1250**	**1250**

Duke Energy Progress (East) Modeled Exports – MW

	Base	DEP TRM
CPLW (Transfer)	400	400
DEC (NCEMC)	0	0
PJM (Ingenco)	6	6
PJM (NCEMC)	330	330
Total	**736**	**736**

Duke Energy Progress (East) Net Interchange – MW

	Base	DEP TRM
	-514	**-514**

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

2021/2022 WINTER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	**DEP TRM**
AEP (TRM)	0	69
CPLE (Transfer)	400	400
DUK (Rowan)	0	0
DUK (DEP TRM)	0	192
SCPSA (Waynesville)	22	22
TVA (SEPA)	14	14
TVA (TRM)	0	19
Total	**436**	**716**

Duke Energy Progress (West) Modeled Exports – MW

	Base	**DEP TRM**
---	---	---
Total	**---**	**---**

Duke Energy Progress (West) Net Interchange - MW

	Base	**DEP TRM**
	-436	**-716**

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

2026 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	0	0
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (PMPA)	149	149
SCPSA (Seneca)	34	34
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (EU)	0	0
SOCO (NCEMC)	0	0
Total	**455**	**455**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	150	150
CPLE (DEP TRM)	0	773
CPLW (Rowan)	0	0
CPLW (DEP TRM)	0	0
DVP (NCEMC)	100	100
Total	**1305**	**2078**

Duke Energy Carolinas Net Interchange

	Base	DEP TRM
	850	**1623**

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

2026 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	DEP TRM
AEP (NCEMC)	100	100
AEP (DEP TRM)	0	100
DEC (Broad River)	850	850
DEC (NCEMC/Catawba)	205	205
DEC (Rowan)	150	150
DEC (DEP TRM)	0	773
DVP (SEPA-KERR)	95	95
DVP (DEP TRM)	0	427
SCEG (DEP TRM)	0	200
SCPSA (DEP TRM)	0	326
Total	**1400**	**3226**

Duke Energy Progress (East) Modeled Exports – MW

	Base	DEP TRM
CPLW (Transfer)	400	400
DEC (NCEMC)	0	0
PJM (Ingenco)	6	6
PJM (NCEMC)	330	330
Total	**736**	**736**

Duke Energy Progress (East) Net Interchange – MW

	Base	DEP TRM
	-664	**-2490**

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

2026 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	**DEP TRM**
AEP (TRM)	0	0
CPLE (Transfer)	400	400
DUK (Rowan)	0	0
DUK (DEP TRM)	0	0
SCPSA (Waynesville)	22	22
TVA (SEPA)	14	14
TVA (TRM)	0	0
Total	**436**	**436**

Duke Energy Progress (West) Modeled Exports – MW

	Base	**DEP TRM**
---	---	---
Total	**---**	**---**

Duke Energy Progress (West) Net Interchange – MW

	Base	**DEP TRM**
	-436	**-436**

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

Appendix B
Transmission Plan Major Project Listings - Reliability Projects

2016 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)							
Project ID	**Reliability Project**	**Issue Resolved**	**Status**[1]	**Transmission Owner**	**Projected In-Service Date**	**Estimated Cost ($M)**[2]	**Project Lead Time (Years)**[3]
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	Planned	DEP	6/1/2025	15	4
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV Substation	Address loading on Castle Hayne - Folkstone 115 kV Line.	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	Address loading on Raeford 230/115 kV transformer.	Planned	DEP	6/1/2018	16	1.5
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock - Jacksonville 230 kV Line	Planned	DEP	6/1/2020	31	3.5
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock - Morehead Wildwood 115 kV Line	Planned	DEP	6/1/2020	30	3.5
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	Mitigate transformer bank and 115 kV feeder loading	Underway	DEP	12/1/2016	19	.5
0034	Sutton - Castle Hayne 115 kV North line Rebuild	Mitigate contingency loading	Planned	DEP	6/1/2019	9	2.5

2016 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)							
Project ID	Reliability Project	Issue Resolved	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($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	Transmission required to interconnect two 1x1 combined cycle generating units	Planned	DEP	12/1/2019	30	3.5
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	Transmission required to interconnect two 1x1 combined cycle generating units	Planned	DEP	12/1/2019	30	3.5
0038	Reconductor Harley 100 kV Lines (Tiger - Campobello)	Mitigate contingency loading	Planned	DEC	6/1/2021	20	4
TOTAL						**214**	

[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.

[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**

Table of Contents

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: 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.

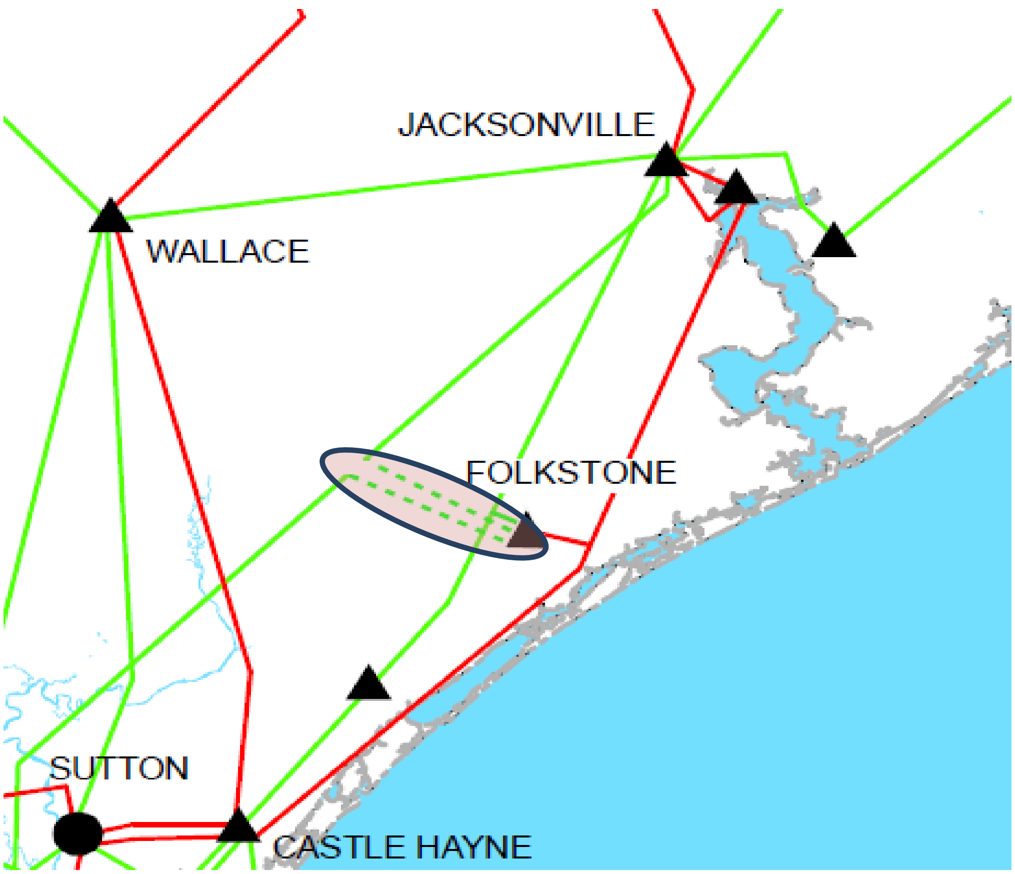
Other Transmission Solutions Considered
Rebuild, reconductor existing Castle Hayne-Folkstone 115 kV line.

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

C-1

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	1.5 years
Estimated Cost	$16 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.

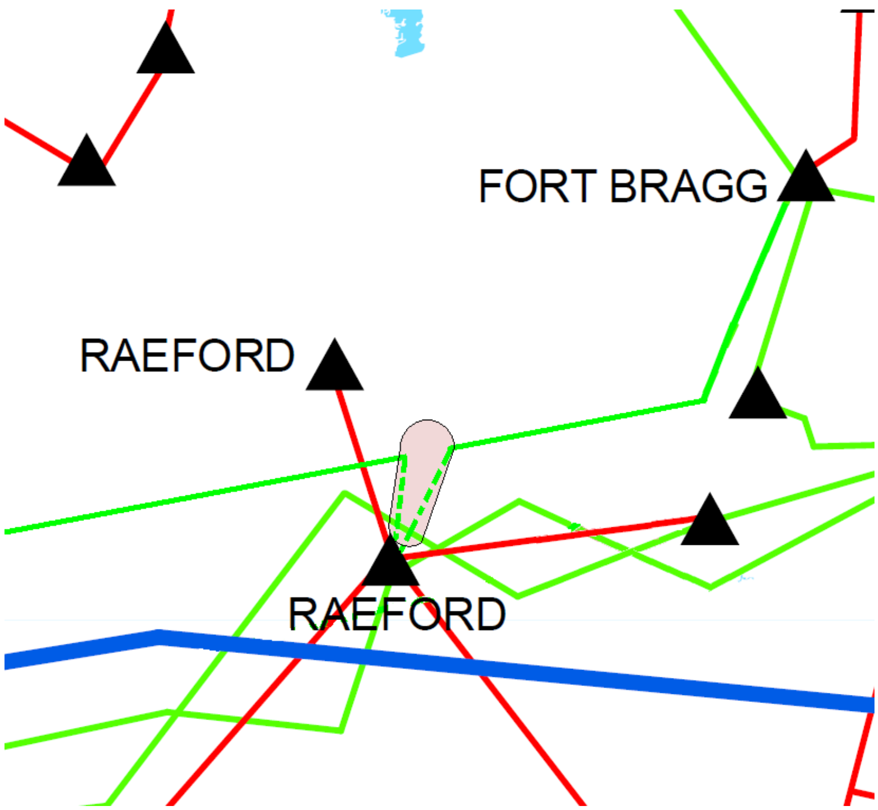
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

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

C-2

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: 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	6/1/2025
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.

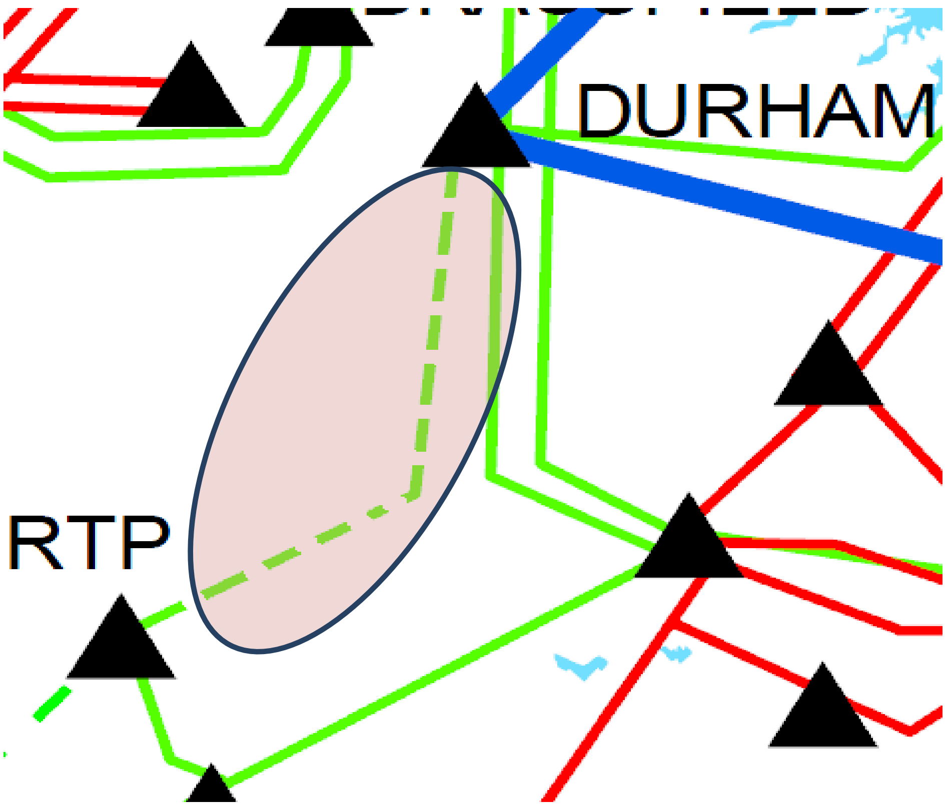
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV Subs.

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

C-3

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: 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	4.5 years
Estimated Cost	$37 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.

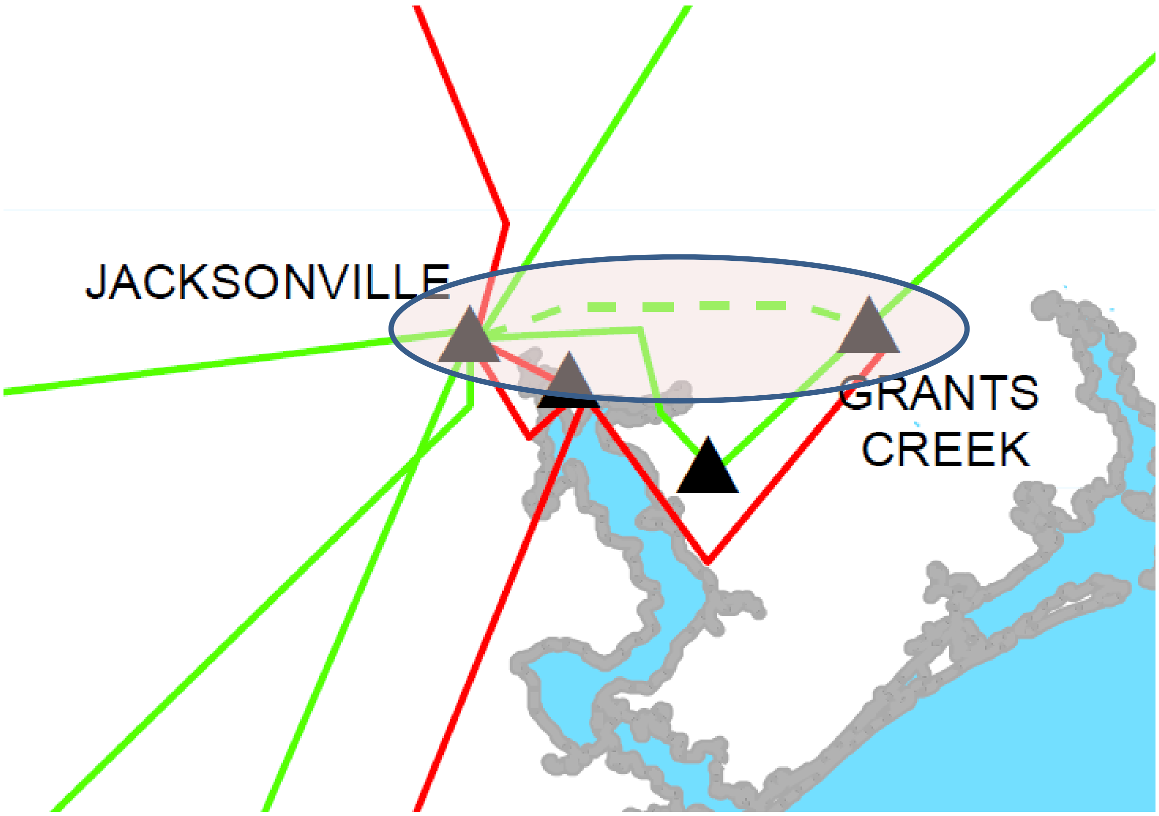
Other Transmission Solutions Considered
Construct 230 kV feeder from Jacksonville to Camp LeJeune Tap.

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 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	4.5 years
Estimated Cost	$32 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.

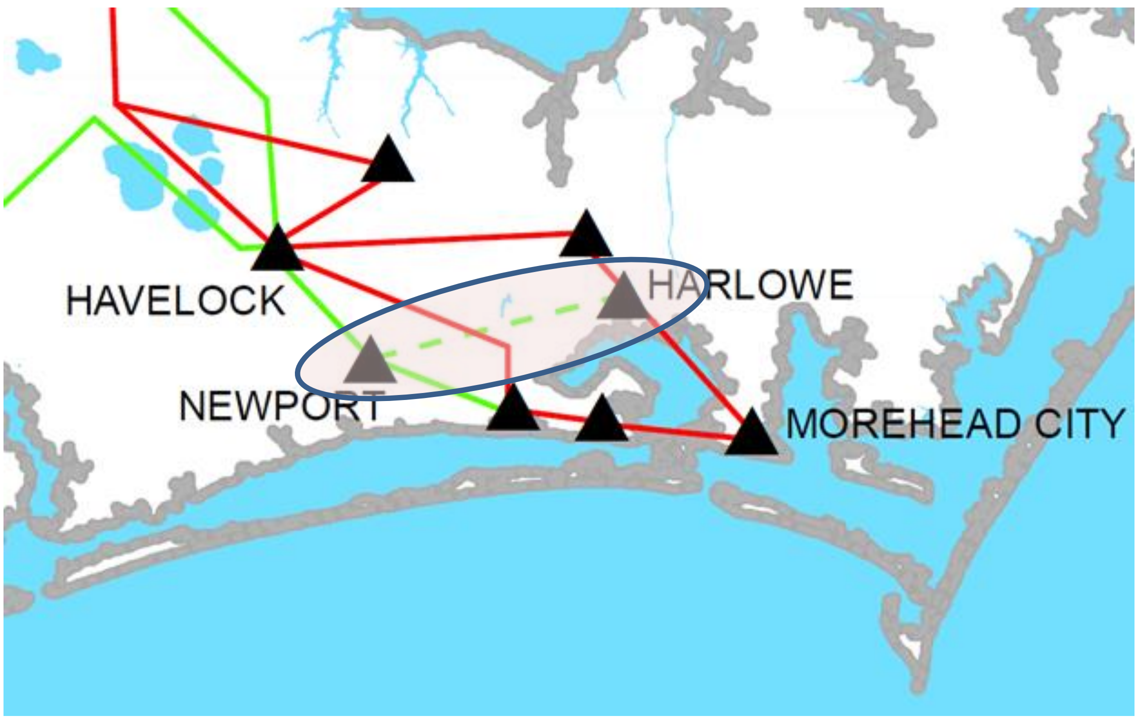
Other Transmission Solutions Considered
Convert Havelock-Morehead Wildwood115 kV North line to 230 kV.

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	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2016
Estimated Time to Complete	1.5 years
Estimated Cost	$13 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 will exceed the feeder capacity and the transformer bank rating at the Ft. Bragg Woodruff Street 230kV Substation. DEP has been working with South River EMC and Central EMC to manage the loading on this feeder for several years and we have jointly agreed that this is the best alternative to alleviate these issues.

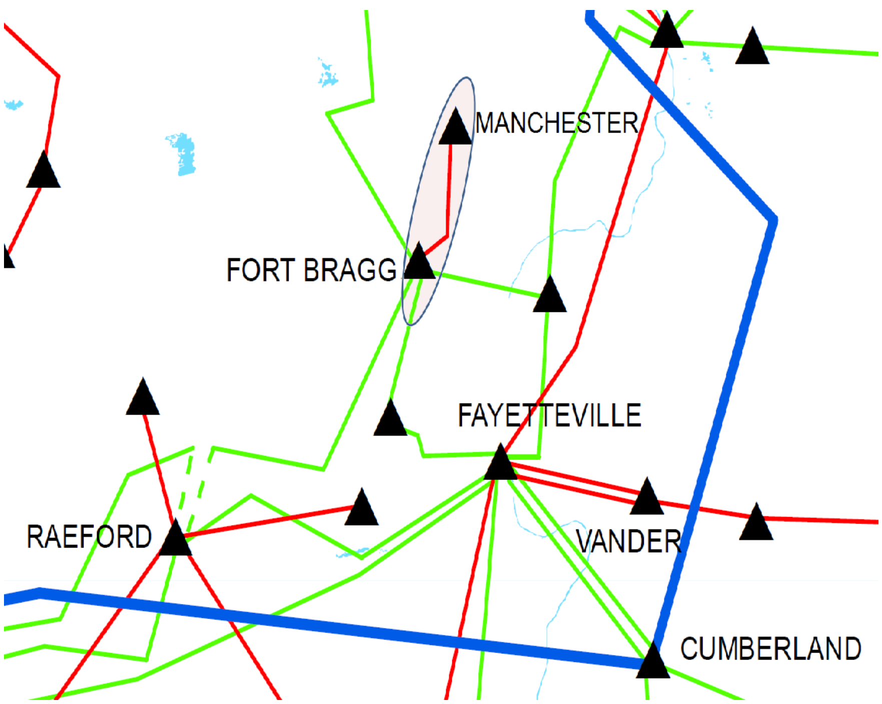
Other Transmission Solutions Considered
Convert 115 kV feeder to 230 kV.

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 & 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 will exceed the feeder capacity and the transformer bank rating at the Ft. Bragg Woodruff Street 230kV Substation. DEP has been working with South River EMC and Central EMC to manage the loading on this feeder for several years and we have jointly agreed that this is 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	2.5 years
Estimated Cost	$9 M

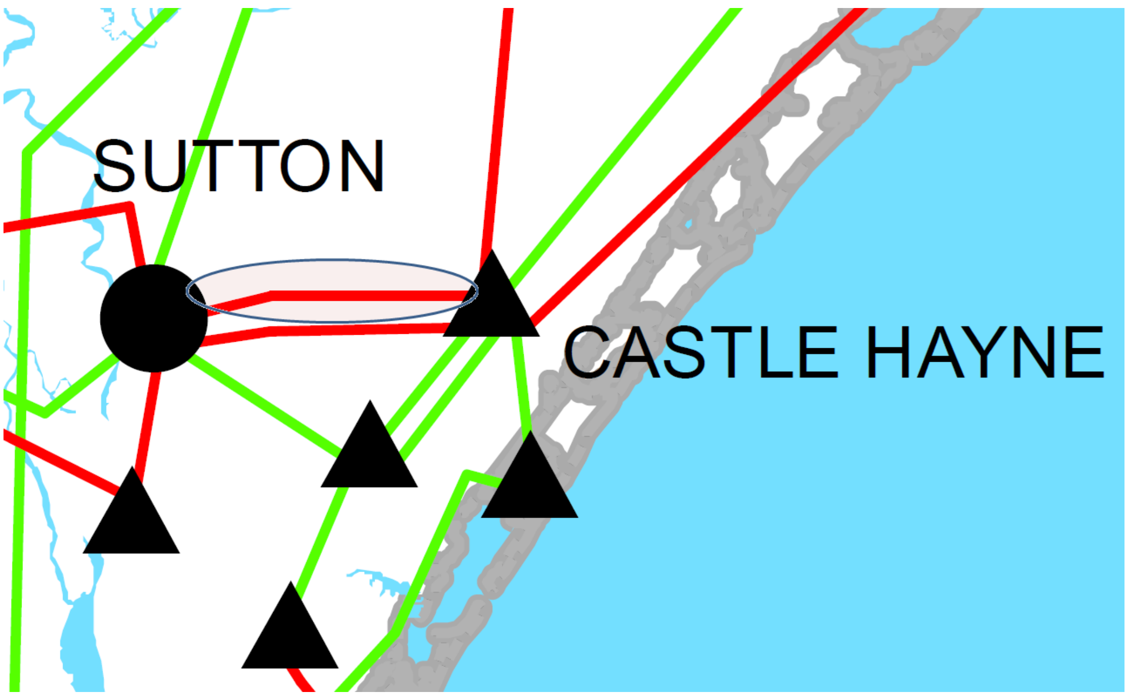
Narrative Description of the Need for this Project
By 2019, with all area generation online, the loss of the Sutton Plant - Castle Hayne 115 kV South line will cause the Sutton Plant - Castle Hayne 115 kV North line to exceed its thermal rating.

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	3.5 years
Estimated Cost	$30 M

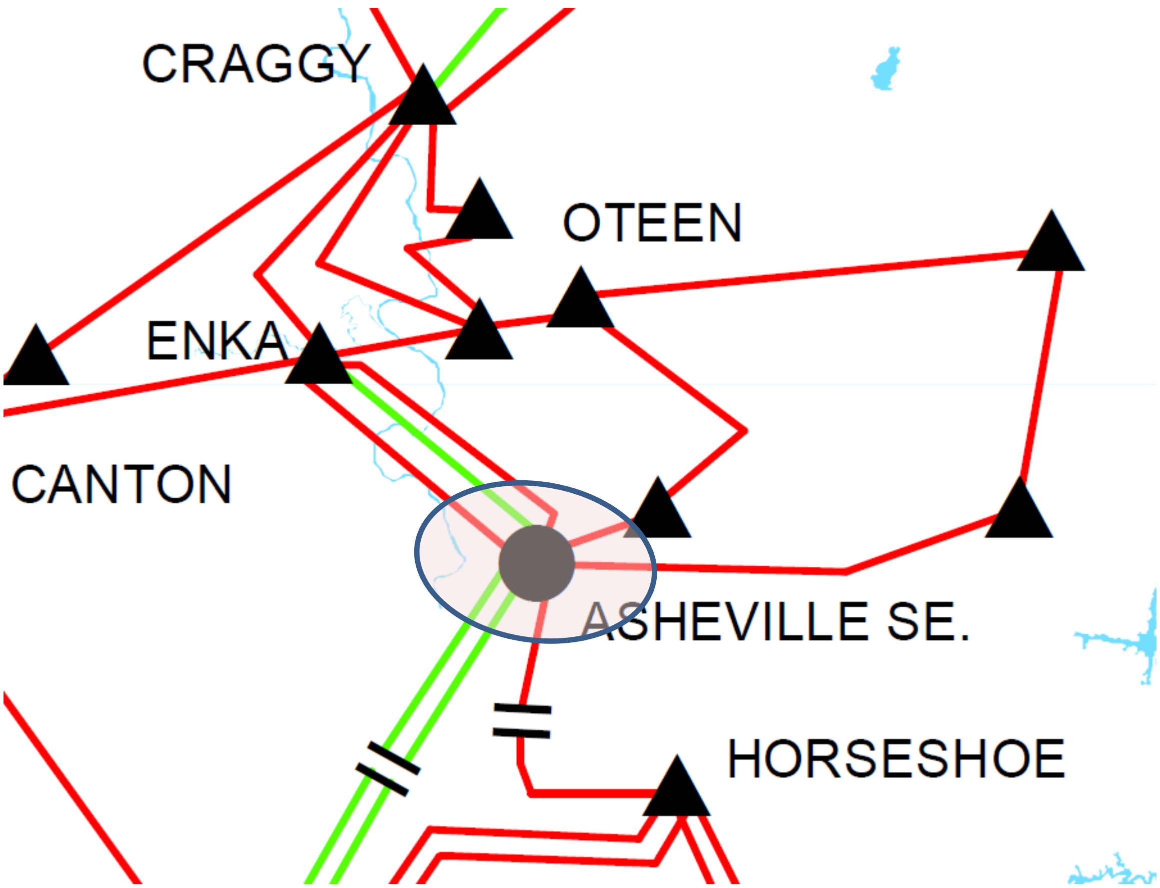
Narrative Description of the Need for this Project
Interconnect two combined cycle units.

Other Transmission Solutions Considered
These are generation interconnection 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	3.5 years
Estimated Cost	$30 M

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

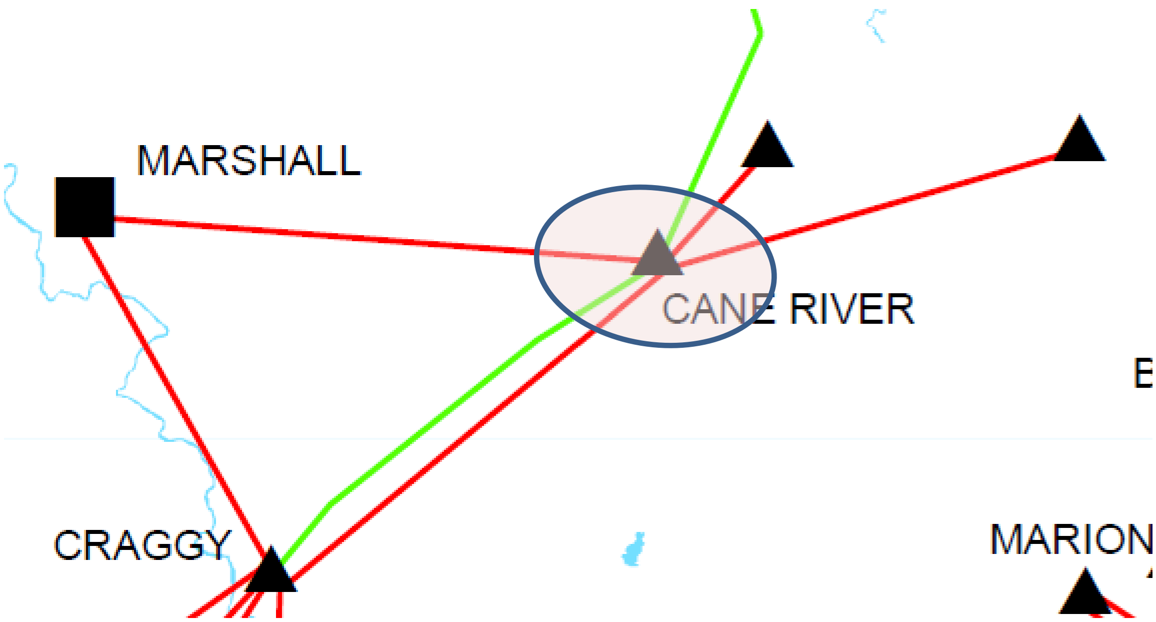
Other Transmission Solutions Considered
Considered constructing new interconnections

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

C-9

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 – Reconductor Harley 100 kV Lines (Tiger - Campobello)

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	6/1/2021
Estimated Time to Complete	4 years
Estimated Cost	$20 M

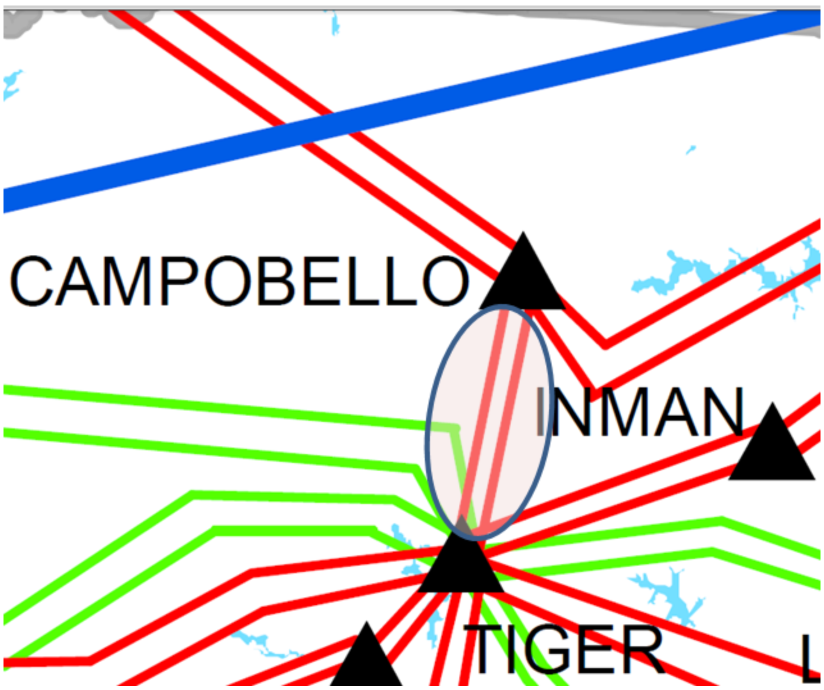
Narrative Description of the Need for this Project
Under high levels of transfer to CPLW, these lines may become overloaded because they are on one of the two 100 kV paths that connect DEC to CPLW.

Other Transmission Solutions Considered
New transmission line(s)

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

Reconductor Harley 100 kV Lines (Tiger - Campobello)

- **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.



Appendix D
Additional Sensitivities Studies

Sensitivity #1 – Long-term Outage of Brunswick 1 & 2					
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**Date Needed[1]**	**($M)[2]**
Reconductoring 8.65 miles of the Marion - Mullins 115kV with 3-1590 MCM ACSR or equivalent	Line overloads for loss of transformer	DEP	3	2026	9
Reconductoring 7.37 miles of the Shaw AFB - SCEG Eastover 115kV with 3-795 MCM ACSR or equivalent (would need to coordinate project with SCEG)	Line overloads for loss of parallel common-tower lines	DEP	3	2026	8

[1] The tables in Appendix D reflect the date the project is needed in order to implement the local economic study.

[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.

Sensitivity #2 – Address Specific Operating Procedures					
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**Date Needed**[1]	**($M)**[2]
Install series reactors on Wateree - Great Falls 100 kV	DEC line overloads for loss of parallel line	DEC	2	2026	5
	DEP line overloads for loss of parallel line	DEP			
Reconductor 7.96 miles of the Rockingham - West End 230 kV West	Line overloads for loss of parallel line	DEP	3	2033	8
Reconductor 14.6 miles of Marion - Dillon Tap 115 kV	Line overloads for loss of parallel line	DEP	3	2034	15

[1] The tables in Appendix D reflect the date the project is needed in order to implement the local economic study.

[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.

Appendix E
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2015 Plan[1]			2016 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	DEP	Planned	6/1/2024	15	Planned	6/1/2024	15
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV Substation	Address loading on Castle Hayne - Folkstone 115 kV Line.	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	Address loading on Raeford 230/115 kV transformer.	DEP	Planned	6/1/2018	20	Planned	6/1/2018	16

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2015 Plan[1]			2016 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Jacksonville 230 kV Line	DEP	Planned	6/1/2020	37	Planned	6/1/2020	31
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Morehead Wildwood 115 kV Line	DEP	Planned	6/1/2020	32	Planned	6/1/2020	30
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	Mitigate transformer bank and 115 kV feeder loading	DEP	Underway	6/1/2016	13	Underway	12/1/2016	19
0034	Sutton - Castle Hayne 115 kV North line Rebuild	Mitigate contingency loading	DEP	Planned	6/1/2018	10	Planned	6/1/2018	9
0035	Reconductor Norman 230 kV Lines (McGuire - Riverbend)	Mitigate loading issues that were aggravated by retirement of Riverbend generation	DEC	In-Service	12/1/2015	15	_	_	_

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2015 Plan[1]			2016 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($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	Transmission required to interconnect two 1x1 combined cycle generating units	DEP	_	_	_	Planned	12/1/2019	30
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	Transmission required to interconnect two 1x1 combined cycle generating units	DEP	_	_	_	Planned	12/1/2019	30
0038	Reconductor Harley 100 kV Lines (Tiger - Campobello)	Mitigate contingency loading caused by loss of both Pisgah - Shiloh 230 kV lines	DEC	_	_	_	Planned	6/1/2021	20
TOTAL						**156**			**214**

[1] Information reported in Appendix B of the NCTPC 2015 - 2025 Collaborative Transmission Plan" dated January 14, 2016.

[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.

Deferred: Projects with this status were identified in the 2015 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2016 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 F
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
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
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
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
WCMP	Western Carolinas Modernization Project