North Carolina Transmission Planning Collaborative

Report on the NCTPC 2013-2023 Collaborative Transmission Plan

December 6, 2013
DRAFT

2013 – 2023 NCTPC Study
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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, and ElectriCities of North Carolina) and other stakeholders an opportunity to participate in the electric transmission planning process for the Participants in the State of North Carolina;

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 control areas of DEC and DEP; and

4) develop a single coordinated transmission plan for the Participants in North Carolina that includes reliability and enhanced transmission access 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 Enhanced Transmission Access Planning ("ETAP") 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 2012-2022 Collaborative Transmission Plan (the "2012 Collaborative Transmission Plan" or the "2012 Plan") was published in January 2013.

This report documents the current 2013 – 2023 Collaborative Transmission Plan ("2013 Plan") for the Participants in North Carolina. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2013 reliability planning study scope and methodology. The NCTPC Process document and 2013 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.net/nctpc/home.jsp.

The scope of the 2013 Reliability Planning Process included a base reliability study and an analysis of resource supply options. 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 study was done with the assumption of business as usual except that DEC - DEP merger related upgrades were included in the base models. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2018 through 2023 with the Participants' planned Designated Network Resources ("DNRs"). The 2013 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2013 Study also allowed for adjustments to existing plans where necessary.

While the overall NCTPC Process (Figure 1 in Section II) includes both a Reliability Planning Process and an Enhanced Transmission Access Planning Process, the 2013 NCTPC Process focused exclusively on the Reliability Planning Process, because stakeholders did not request any Enhanced Transmission Access scenarios for the 2013 Study.

The NCTPC reliability study results affirmed that the planned DEC and DEP transmission projects identified in the 2013 Plan continue to satisfactorily address the reliability concerns identified in the 2013 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2013 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

For the 2013 Report, projects in Appendix B have been divided into Reliability Projects (B-1) and Merger Projects (B-2). Projects in the 2013 Plan are those projects identified in the base reliability study (B-1) and those projects that DEC and DEP have committed to construct as a result of the DEC - DEP Merger (B-2). 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. Appendix C provides a more detailed description of each project in the 2013 Plan. Appendix C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

The total estimated cost for the nine projects included in the 2013 Plan for reliability is $234 million as documented in Appendix B-1. This compares to the original 2012 Plan estimate of $318 million for eleven 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 2012 Plan.

As a merger commitment, DEC and DEP agreed to construct a total of nine projects with a cost of approximately $116 million. Of these nine projects, four have cost estimates greater than $10 million and are documented in Appendix B. One of these four projects, the Greenville-Kinston Dupont 230 kV Line, was already a reliability project in the 2011 Plan with a target date of June 1, 2017. As part of the DEC - DEP merger, a commitment was made to accelerate this project to June 1, 2014 and increase the line capacity. This project is grouped with the Reliability projects in Appendix B-1 because it was already in the 2011 Plan. The remaining three merger projects are listed in Appendix B-2. The total estimated cost for the three merger projects in the 2013 Plan is $67 million. This compares to the 2012 Plan estimate of $59 million for the same three merger projects. The 2013 study analysis determined that the DEC – DEP merger projects did not negatively impact any existing projects in the Plan.

The modified projects for DEP and DEC in the 2013 Collaborative Transmission Plan, relative to the 2012 Plan, include three DEP projects that were placed in service. The three DEP projects placed in service were:

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- Brunswick 1 – Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing
- Jacksonville Static VAR Compensator
- Folkstone 230/115 kV Substation

There are revised in-service dates and scope changes for the following previously identified projects:

- Raeford 230 kV Substation – revised from replacing two transformer banks to adding a 3rd bank
- Durham-RTP 230 kV Line, Reconductor – revised target date to 6/1/2023
- Lilesville-Rockingham 230 kV Line #3 – Construct new line – revised target date to 12/31/13.

In addition, one DEC project was removed from the 2013 Plan. This project is:

- Reconductor London Creek 230 kV Lines (Peach Valley Tie – Riverview Switching Station #1 & #2

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 2013, the PWG analyzed, among its resource supply options, cases that examine 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. Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined.

Analysis of the sixteen hypothetical transfer scenarios did not require any additional transmission projects for DEP beyond those in the 2013 Collaborative Plan. However, one major project was identified for DEC. This consisted of, for certain scenarios, the reconductoring of the DEC portion of the existing 115 kV tie lines between DEC and SCEG. The estimated cost for the upgrade is $16 M. The specific facility additions for the hypothetical transfer scenarios are summarized in Appendix D. For the studied conditions, the transfers did not drive any new issues in PJM.

In this 2013 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 (Duke Energy Carolinas, Duke Energy Progress, 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 Participants in the State of North Carolina;

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 control areas of DEC and DEP; and

4) develop a single coordinated transmission plan for the Participants in North Carolina that includes reliability and enhanced transmission access 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 Enhanced Transmission Access Planning ("ETAP") 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 Planning Working Group ("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 Second Revised Participation Agreement dated January 12, 2010 which is posted at http://www.nctpc.net/nctpc/home.jsp. Figure 1 illustrates the major steps associated with the NCTPC Process.

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 NCPTC, 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 in Figure 1. 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. Enhanced Transmission Access Planning Process

The ETAP Process is the economic planning process that allows the TAG participants to propose economic hypothetical transfers to be studied as part of the transmission planning process. The ETAP Process provides the means to evaluate the impact of potential supply resources inside and outside the Control Areas of the Transmission Providers. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources. In addition, this economic analysis would include, if requested, the evaluation of Regional Economic Transmission Paths (RETPs) that would facilitate potential regional point-to-point economic transactions. The ETAP Process follows the steps outlined in Figure 1. The OSC approves the scope of the ETAP study (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 ETAP study results.

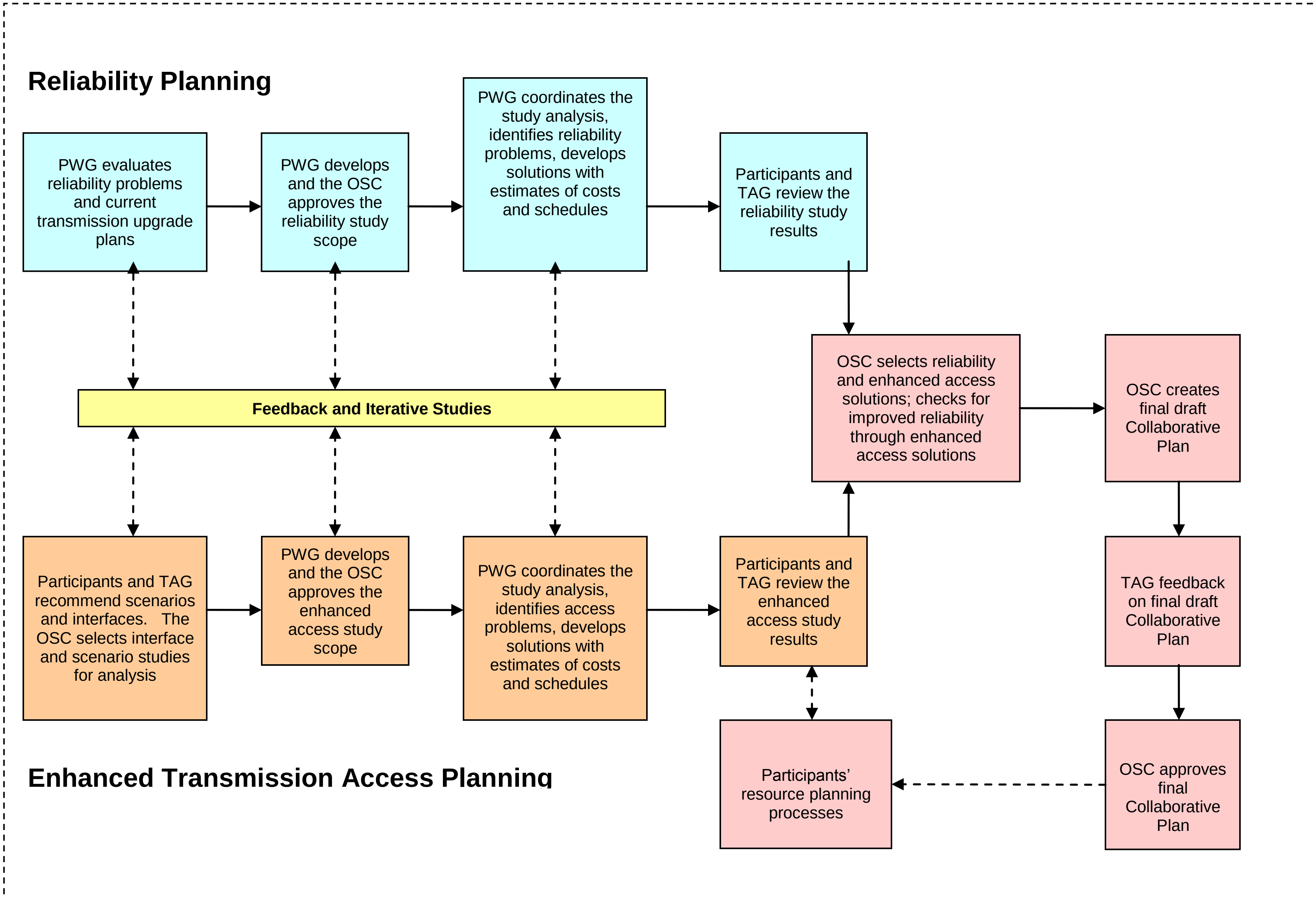
The ETAP Process begins with the Participants and TAG members proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces are compiled by the PWG and then evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle. The PWG coordinates the development of the enhanced transmission access 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 ETAP Process include the estimated costs and schedules to provide the increased transmission capabilities. The enhanced transmission access 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 (Figure 1 below) includes both a Reliability Planning Process and an Enhanced Transmission Access Planning Process, the 2013 NCTPC Process focused exclusively on the Reliability Planning Process because stakeholders did not request any Enhanced Transmission Access scenarios for the 2013 Study. Enhanced Transmission Access scenarios will again be solicited for the 2014 Study and included if appropriate.

Figure 1

2013 NCTPC Process Flow Chart



II.D. Collaborative Transmission Plan

Once the reliability and ETAP studies are completed, the OSC evaluates the results and the PWG recommendations to determine if any proposed enhanced transmission access 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. 2013 Reliability Planning Study Scope and Methodology

The 2013 Reliability Planning Process included a base reliability study and an analysis of resource supply options. 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 study was done with the DEC – DEP merger projects included in the cases. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2018 summer through 2023 summer with the Participants' planned Designated Network Resources ("DNRs"). The 2013 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2013 Study also allowed for adjustments to existing plans where necessary.

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 2013, the PWG analyzed, among its resource supply options, cases that examine the impacts of sixteen different hypothetical transfers into and out of the DEC and DEP systems in 2023 across the DEC and DEP interfaces with neighboring utilities. Each of these transfers 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.

These resource supply scenarios include the following:

Table 4
Resource Supply Options
2023 Hypothetical Transfer Scenarios

Resource From	Sink	Test Level (MW)
NORTH – PJM	DEC	1,000
SOUTH – SOCO	DEC	1,000
SOUTH – SCEG	DEC	1,000
SOUTH – SCPSA	DEC	1,000
EAST – DEP(CPLE)	DEC	1,000
WEST – TVA	DEC	1,000
NORTH – PJM	DEP(CPLE)	1,000
SOUTH – SCEG	DEP(CPLE)	1,000
SOUTH – SCPSA	DEP(CPLE)	1,000
WEST – DEC	DEP(CPLE)	1,000
WEST – DEC	SOCO	1,000
NORTH – PJM	DEC / DEP(CPLE)	1,000 / 1,000
WEST - DEC / DEP(CPLE)	PJM	1,000 / 1,000
EAST – DEP(CPLE)	PJM	1,000
WEST – DEC	PJM	1,000
SOUTH – SOCO (Note 1.)	PJM	1,000

Note 1. – This hypothetical transfer is intended to evaluate the impact of a 1000 MW Southern Co transaction through the DEC/DEP transmission system into PJM.

This year the NCTPC also performed a joint inter-regional study with PJM to evaluate the interaction of various resource supply scenarios that model hypothetical transfers (7 of the 16 scenarios in Table 4) across the NC – PJM interface. The PWG coordinated with PJM planning staff to perform this joint inter-regional study as part of the overall 2013 NCTPC Study Scope. NCTPC and PJM exchanged models, contingency and monitored element files so that each could test the impact of the other company's contingencies on its transmission system. The power flow analyses assumed a 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 2013 Collaborative Transmission Plan addressed a ten-year planning horizon through 2023. The study year for the joint inter-regional NCTPC – PJM study was 2023 summer. The study years chosen for the 2013 Study are listed in Table 5.

Table 5
Study Years

Study Year / Season	Analysis
2018 Summer	Near-term base reliability
2018/2019 Winter	Near-term base reliability
2023 Summer	Long-term base reliability, and resource supply options, including inter-regional NCTPC – PJM study

To identify projects required in years other than the base study years of 2018 and 2023, line loading results for those base study years were extrapolated into future years assuming the line loading growth rates in Table 6. This allowed assessment of transmission needs throughout the planning horizon. The line loading growth rates are based on each Balancing Authority's individual load growth projection.

Table 6
Line Loading Growth Rates

Company	Line Loading Growth Rate
DEC	1.7 % per year
DEP	1.5 % per year

2. Network Modeling

The network models developed for the 2013 Study included new transmission facilities and upgrades for the 2018 and 2023 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2012 Collaborative Transmission Plan. Table 7 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2018 and 2023 models. Table 8 lists the generation facility additions and retirements included in the 2018 and 2023 models.

Table 7
Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2018 Base	2023 Base & Sensitivities
DEP	Converted Asheville - Enka 115 kV Line to 230 kV	Yes	Yes
DEP	Asheville - Enka 115 kV West Line new construction	Yes	Yes
DEP	Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg WS 230 kV Line	Yes	Yes
DEP	Brunswick - Castle Hayne 230 kV River Crossing	Yes	Yes
DEP	Jacksonville 230 kV SVC	Yes	Yes
DEP	Folkstone 230/115 kV	Yes	Yes
DEP	Harris Plant - RTP 230 kV Line	Yes	Yes
DEP	Brunswick#1-Jacksonville 230 kV Line, Loop-in to Folkstone	No	Yes
DEP	Greenville - Kinston DuPont 230 kV Line	Yes	Yes
DEP	Durham - RTP 230 kV Line	No	Yes

Company	Transmission Facility	2018 Base	2023 Base & Sensitivities
DEC	Reconductored Caesar 230 kV Line from Pisgah Tie to Shiloh Switching Station	Yes	Yes

Table 8

Major Generation Facility Additions and Retirements in Models

Company	Generation Facility	2018	2023
DEC	Retired Buck 5-6 (256 MW)	Yes	Yes
DEC	Retired Dan River 1-3 (276 MW)	Yes	Yes
DEC	Retired Riverbend 4-7 (454 MW)	Yes	Yes
DEC	Retired Buck CTs (62 MW)	Yes	Yes
DEC	Retired Buzzard Roost CTs (196 MW)	Yes	Yes
DEC	Retired Dan River CTs (48 MW)	Yes	Yes
DEC	Retired Riverbend CTs (64 MW)	Yes	Yes
DEC	Added Cleveland Co. CTs (716 MW)	Yes	Yes
DEC	Added Cliffside Unit 6 (825 MW)	Yes	Yes
DEC	Added Dan River CC (650 MW)	Yes	Yes
DEP	Retired Lee Units 1-2 (200 MW)	Yes	Yes
DEP	Retired Sutton Units 1-3 (616 MW)	Yes	Yes
DEP	Retired Cape Fear Units 5-6 (323 MW)	Yes	Yes
DEP	Retired Weatherspoon Units 1-3 (177 MW)	Yes	Yes
DEP	Added Wayne Co. CC (920 MW)	Yes	Yes
DEP	Added Sutton Plant CC (628 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 control 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 control areas. Interchange tables for the summer and winter base cases, and the DEP Transmission Reliability Margin ("TRM") cases[1], discussed in Section III.D, are in Appendix A.

For the joint NCTPC – PJM inter-regional scenarios, each party provided a list of resource supply assumptions. Generation was dispatched for each control area in the cases to meet load in accordance with a security constrained economic dispatch order. Generation, interchange and other assumptions were coordinated between the NCTPC and PJM as needed. Generation with filed Interconnection Service Agreements and any upgrades were taken into account in this dispatch order.

III.B. Study Criteria

The results of the base reliability study and the resource supply option study were evaluated using established planning criteria, while recognizing differences between the systems of DEC, DEP, and PJM. 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 2012 series NERC Multiregional Modeling Working Group (MMWG) model for the systems external to DEC and DEP. The MMWG

[1] 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.

model of the external systems, in accordance with NERC Multiregional Modeling Working Group ("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. The PJM system model representation was the latest system model developed by PJM. 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 ("TRM") 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 control 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 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 re-dispatched 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	

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 2018 and 2023 summer peak base cases with a Brunswick 1 unit outage, a Harris 1 unit outage, or a Robinson 2 unit outage, and from the 2018/2019 winter peak case with an Asheville 1 unit outage, with the remainder of TRM addressed by miscellaneous unit de-rates.

To understand regional impacts on each other's system, DEC, DEP, and PJM 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, DEP, and PJM systems were shared with all Participants. Solutions of known issues within DEC and DEP were discussed. New or emerging issues identified in the 2013 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 to allow evaluation of project acceleration.

III.F. Assessment and Problem Identification

DEC, DEP, and PJM 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, DEP, and PJM. The reliability issues identified from the assessments of both the base reliability cases and the resource supply option scenarios were documented and shared within the PWG. These results will be reviewed and discussed with their respective stakeholder groups for feedback.

III.G. Solution Development

The 2013 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 2012 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 rough, planning cost estimates and construction schedules for the solution alternatives.

For the joint NCTPC – PJM inter-regional scenarios, NCTPC and PJM tested the effectiveness of the potential solutions using the cases, methodologies, assumptions and criteria discussed earlier. NCTPC and PJM developed rough, planning-level cost estimates 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.

For the resource supply options, the scenarios included examining the system impacts of sixteen different hypothetical transfers into and out of the DEC and DEP systems. Seven of these hypothetical transfer scenarios involved PJM and required a joint inter-regional evaluation to test potential solutions in and out of PJM and the combined DEC and DEP systems (referred to as NCTPC). Analysis of the results identified potential issues that each option may create on the DEC, DEP, and PJM transmission systems. Solutions to address these issues were identified and evaluated based on cost, benefit, and risk. From the evaluation, the NCTPC and PJM 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. The preferred set of transmission improvements developed by the NCTPC and PJM will be reviewed and discussed with their respective stakeholder groups for their feedback.

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

For both the DEC and DEP control 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 2015, 2016, 2017, and 2019 summer timeframes. The limiting facilities identified in the PWG study of base reliability and of the resource supply option examining hypothetical new generation 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 2013 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 2013 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 2013 Plan are those projects identified in the base reliability study and DEC-DEP merger projects. 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 nine reliability projects included in the 2013 Plan is $234 million as documented in Appendix B-1. This compares to the 2012 Plan estimate of $318 million for eleven 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 F for a detailed comparison of this year's Plan to the 2012 Plan.

As a merger commitment, DEC and DEP agreed to construct a total of nine projects with a cost of approximately $116 million. Of these nine projects, three have cost estimates greater than $10 million and are documented in Appendix B. One of these four projects, the Greenville-Kinston Dupont 230 kV Line, was already a reliability project in the 2011 Plan with a target date of June 1, 2017. As part of the DEC - DEP merger, a commitment was made to accelerate this project to June 1, 2014 and increase the line capacity. This project is grouped with the Reliability projects in Appendix B-1 because it was already in the 2012 Plan. The remaining three merger projects are listed in Appendix B-2. The total estimated cost for the three merger projects in the 2013 Plan is $67 million. This compares to the 2012 Plan estimate of $59 million for the same three merger projects. The 2013 study analysis determined that the DEC – DEP merger projects did not negatively impact any existing projects in the Plan.

Appendix C provides a more detailed description of each project in the 2013 Plan. Appendix C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

V. Resource Supply Option 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 2013, the PWG analyzed, among its resource supply options, cases that examine the impacts of sixteen different hypothetical transfers into and out of the DEC and DEP systems – Table 8. Each of these transfers, identified in Table 8, 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 9

Resource Supply Options

2023 Hypothetical Transfer Scenarios

Resource From	**Sink**	**Test Level (MW)**
NORTH – PJM	DEC	1,000
SOUTH - SOCO	DEC	1,000
SOUTH – SCEG	DEC	1,000
SOUTH – SCPSA	DEC	1,000
EAST – DEP(CPLE)	DEC	1,000
WEST – TVA	DEC	1,000
NORTH – PJM	DEP(CPLE)	1,000
SOUTH – SCEG	DEP(CPLE)	1,000
SOUTH – SCPSA	DEP(CPLE)	1,000
WEST – DEC	DEP(CPLE)	1,000
WEST - DEC	SOCO	1,000
NORTH – PJM	DEC/DEP(CPLE)	1,000 / 1,000
WEST - DEC / DEP(CPLE)	PJM	1,000 / 1,000
EAST – DEP(CPLE)	PJM	1,000
WEST - DEC	PJM	1,000
SOUTH – SOCO (Note 1.)	PJM	1,000

Note 1. – This hypothetical transfer is intended to evaluate the impact of a 1000 MW Southern Co transaction through the DEC/DEP transmission system into PJM.

Analysis of the sixteen hypothetical transfer scenarios did not require any additional transmission projects for DEP beyond those in the 2013 Collaborative Plan. However, one major project was identified for DEC. This consisted of, for certain scenarios, the reconductoring of the DEC portion of the existing 115 kV tie lines between DEC and SCEG. The estimated cost for the upgrade is $16 M. The specific facility additions for the hypothetical transfer scenarios are summarized in Appendix D. For the studied conditions, the transfers did not drive any new issues in PJM.

VI. Collaborative Transmission Plan

The 2013 Collaborative Transmission Plan includes nine reliability projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B-1. The total estimated cost for these nine reliability projects in the 2013 Plan is $234 million. This compares to the original 2012 Plan estimate of $318 million for eleven reliability projects. The total estimated cost for the three merger projects in the 2013 Plan is $67 million. This compares to the 2012 Plan estimate of $59 million for the same three merger 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 2012 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 2013 Plan, and includes the following information:

1) Reliability (or Merger) 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 2012 Report and have been deferred beyond the end of the planning horizon based on the 2013 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 C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

Appendix A
Interchange Tables

2018 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	147	147
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	24	24
SCPSA (PMPA)	226	226
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	33	33
SOCO (EU)	187	187
SOCO (NCEMC)	176	176
Total	**1065**	**1065**

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)	50	50
Total	**1255**	**2028**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	190	**963**

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

2018 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	DEP TRM
AEP (NCEMC)	100	100
AEP (NCEMC#2)	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	**1500**	**3326**

Duke Energy Progress (East) Modeled Exports – MW

	Base	DEP TRM
PJM (NCEMC)	165	165
CPLW (Transfer)	0	0
DEC (NCEMC)	33	33
Total	**312**	**312**

Duke Energy Progress (East) Net Interchange - MW

	Base	DEP TRM
	-1302	**-3128**

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

2018 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	**DEP TRM**
CPLE (Transfer)	0	0
DEC (Rowan)	0	0
DEC(DEP TRM)	0	0
TVA (SEPA)	1	1
Total	**1**	**1**

Duke Energy Progress (West) Modeled Exports – MW

	Base	**DEP TRM**
CPLE (Transfer)	0	0
Total	**0**	**0**

Duke Energy Progress (West) Net Interchange – MW

	Base	**DEP TRM**
	-1	**-1**

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

2018/2019 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 (New Horizons/NHEC)	0	0
SCPSA (PMPA)	96	96
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	19	19
SOCO (EU)	187	187
SOCO (NCEMC)	133	133
Total	**707**	**707**

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)	150	150
CPLW (DEP TRM)	0	198
DVP (NCEMC)	50	50
Total	**1255**	**1453**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	548	**746**

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

2018/2019 WINTER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	**DEP TRM**
AEP (NCEMC)	100	100
AEP (NCEMC#2)	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	**1350**	**1350**

Duke Energy Progress (East) Modeled Exports – MW

	Base	**DEP TRM**
CPLW (Transfer)	250	250
DEC (NCEMC)	0	0
PJM (NCEMC)	165	165
Total	**415**	**415**

Duke Energy Progress (East) Net Interchange – MW

	Base	**DEP TRM**
	-935	**-935**

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

2018/2019 WINTER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
AEP (TRM)	0	49
CPLE (Transfer)	250	250
DEC (Rowan)	150	150
DEC (DEP TRM)	0	198
TVA (SEPA)	1	1
TVA (TRM)	0	14
Total	**401**	**662**

Duke Energy Progress (West) Modeled Exports – MW

	Base	DEP TRM
CPLE (Transfer)	0	0
Total	**0**	**0**

Duke Energy Progress (West) Net Interchange - MW

	Base	DEP TRM
	-401	**-662**

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

2023 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 (New Horizons/NHEC)	0	0
SCPSA (PMPA)	268	268
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	35	35
SOCO (EU)	187	187
SOCO (NCEMC)	176	176
Total	**938**	**938**

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)	50	50
Total	**1255**	**2028**

Duke Energy Carolinas Net Interchange

	Base	DEP TRM
	317	**1090**

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

2023 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	**DEP TRM**
AEP (NCEMC)	100	100
AEP (NCEMC #2)	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	**1500**	**3326**

Duke Energy Progress (East) Modeled Exports – MW

	Base	**DEP TRM**
CPLW (Transfer)	0	0
DEC (NCEMC)	34	34
PJM (NCEMC)	330	330
Total	**364**	**364**

Duke Energy Progress (East) Net Interchange – MW

	Base	**DEP TRM**
	-1136	**-2962**

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

2023 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
CPLE (Transfer)	0	0
DEC (Rowan)	0	0
DEC (DEP TRM)	0	0
TVA (SEPA)	1	1
Total	**1**	**1**

Duke Energy Progress (West) Modeled Exports – MW

	Base	DEP TRM
CPLE (Transfer)	0	0
Total	**0**	**0**

Duke Energy Progress (West) Net Interchange – MW

	Base	DEP TRM
	-1	**-1**

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

Appendix B-1
Collaborative Transmission Plan Major Project Listings -
Reliability Projects

2013 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]
0026	Brunswick 1 - Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing	Address loading on Sutton Plant - Castle Hayne 230 kV Line	In-Service	DEP	3/3/2013	27	0
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high imports	In-Service	DEP	6/1/2013	32	0
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	In-Service	DEP	12/1/2012	19	0
0010A	Harris Plant-RTP 230 kV Line, Establish a new 230 kV line by utilizing the Amberly 230 kV Tap, converting existing Green Level 115 kV Feeder to 230 kV operation, construction of new 230 kV line, remove 230/115 kV transformation and connection at Apex US1	Address the need for new transmission source to serve rapidly growing load in the western Wake County area; helps address loading on Cary Regency Park - Durham 230 kV line	Underway	DEP	6/1/2014	59	0.5
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV substation	Address loading on Folkstone – Jacksonville City 115 kV Line	Planned	DEP	6/1/2020	11	4

2013 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]**
0008	Greenville - Kinston DuPont 230 KV Line Construct line	Address loading on Greenville - Everetts 230 kV Line	Underway	DEP	6/1/2014	32	0.5
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	13	4
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	Planned	DEP	6/1/2023	15	4
0027	Reconductor Caesar 230 kV Lines (Pisgah Tie - Shiloh Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line during high imports to DEP West	Underway	DEC	12/31/2013	26	0.5
0014	Reconductor London Creek 230 kV Lines (Peach Valley Tie - Riverview Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line when a 230 kV connected Oconee unit is off line	Removed	DEC			
TOTAL						**234**	

[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.

[4] This project was originally scheduled to be completed 6/1/2017, but was accelerated to 6/1/2014 as part of the DEC - DEP merger mitigation projects.

Appendix B-2
Collaborative Transmission Plan Major Project Listings –
Merger Projects

2013 Collaborative Transmission Plan – Merger Projects (Estimated Cost > $10M)							
Project ID	**Merger Project**	**Issue Resolved**	**Status[1]**	**Transmission Owner**	**Projected In-Service Date**	**Estimated Cost ($M)[2]**	**Project Lead Time (Years)[3]**
M-0001	Lilesville-Rockingham 230KV Line #3 – Construct new line	This project is part of the DEC - DEP merger mitigation projects.	Underway	DEP	12/31/13	14	0.5
M-0002	Person-(DVP) Halifax 230kV Line - Reconductor DVP Section (DVP work)	This project is part of the DEC - DEP merger mitigation projects.	Underway	DEP/ Dominion	6/1/2014	21	1
M-0003	Antioch 500/230kV Substation: Replace Two Transformer Banks	This project is part of the DEC - DEP merger mitigation projects.	Underway	DEC	6/1/2014	32	1
TOTAL						**67**	

[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-1 Collaborative 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: 0026 - Brunswick 1 - Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing

Project Description
This project consists of constructing a new 230 kV line under the Cape Fear River.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	3/3/2013
Estimated Time to Complete	0 years
Estimated Cost	$27 M

Narrative Description of the Need for this Project
The common tower outage of the two lines (at river crossing) that run from Brunswick Plant to Castle Hayne can cause the thermal rating of the Sutton Plant - Castle Hayne 230 kV Line to be exceeded. This event will also require significant reduction in Brunswick units output for several days to several months, depending upon the damage caused to the lines and towers. Studies show that separating these lines at their common river crossing will eliminate overloading issues for the 10 year planning horizon, will reduce any impact on Brunswick Plant operation, and will increase reliability to the Wilmington load area.

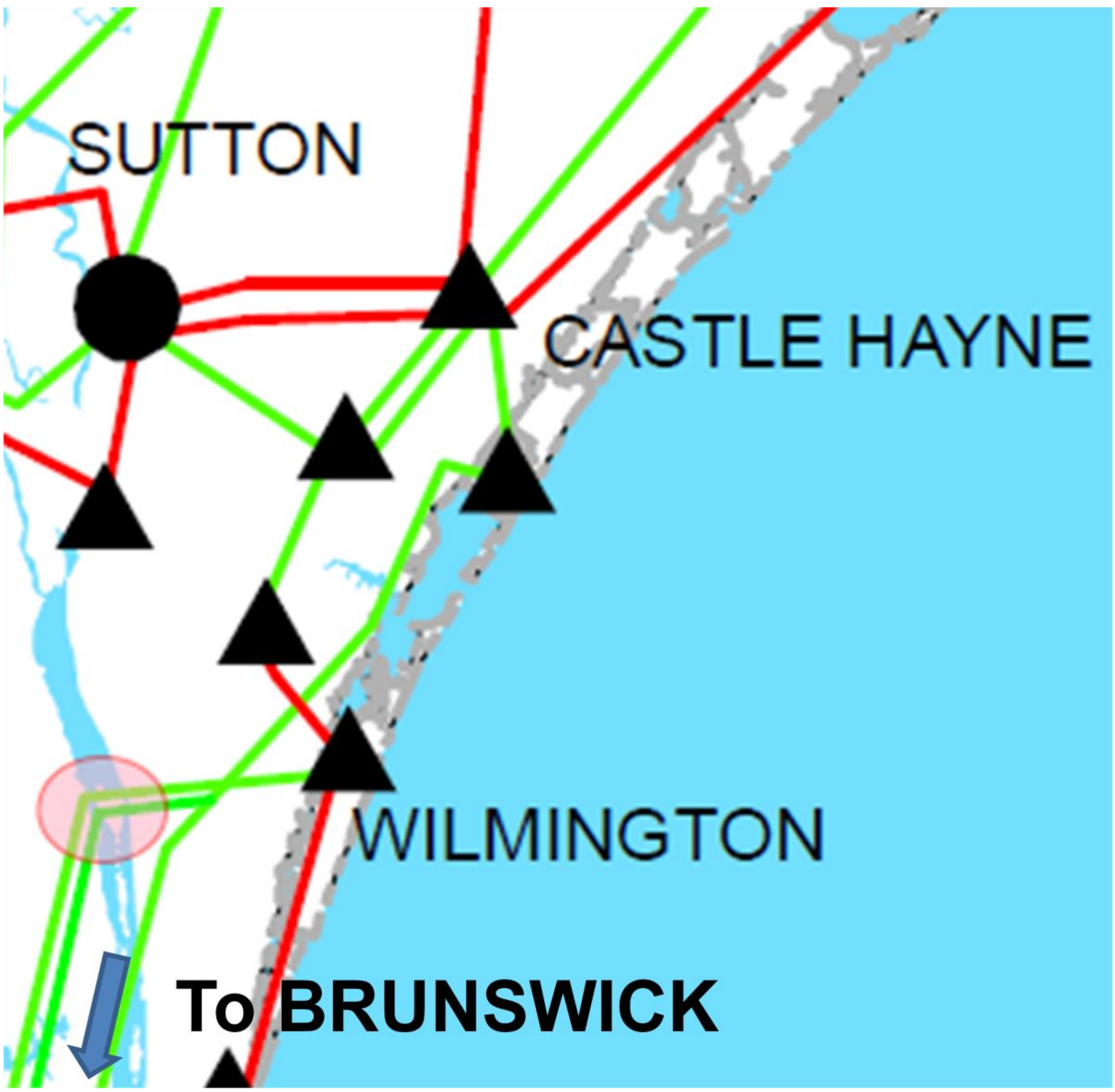
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

Why this Project was Selected as the Preferred Solution
Cost, feasibility and improved area reliability.

C-1

Brunswick 1 - Castle Hayne 230 kV Line

- **NERC Category B Violations**
- **Problem:** The common tower outage of the two lines (at river crossing) that run from Brunswick Plant to Castle Hayne can cause the thermal rating of the Sutton Plant - Castle Hayne 230 kV Line to be exceeded.
- **Solution:** Constructing a new 230 kV line under the Cape Fear River.



Project ID and Name: 0022 - Jacksonville Static VAR Compensator (SVC)

Project Description
Install a 300 MVAR 230 kV Static VAR Compensator (SVC) at the Jacksonville 230 kV Substation.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	5/14/2013
Estimated Time to Complete	0 years
Estimated Cost	$31 M

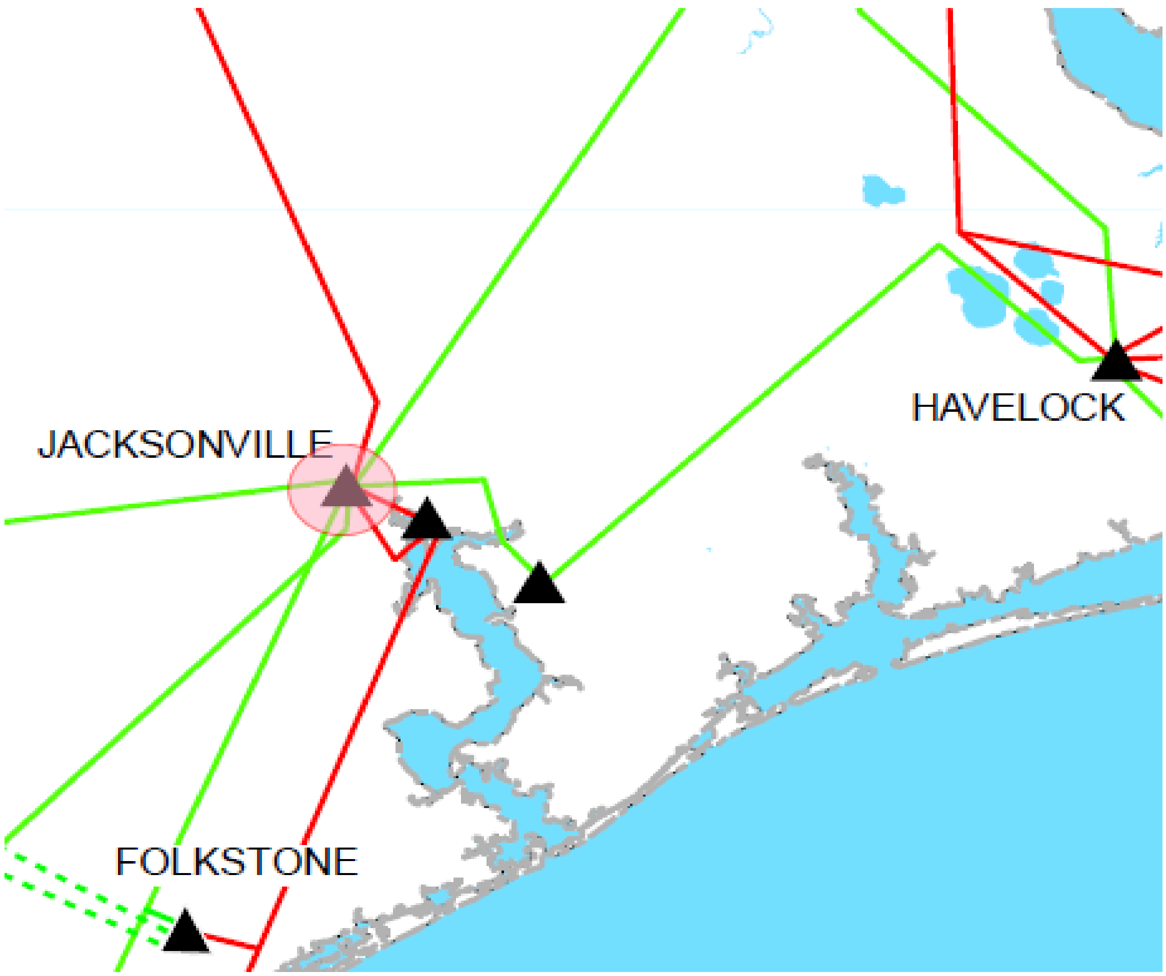
Narrative Description of the Need for this Project
This project was identified during a dynamic evaluation of DEP's East System during periods of increased imports. The analysis indicated that under certain faulted conditions that DEP East's transmission network along the coast of NC would be unable to maintain adequate voltage support. The lack of voltage support in the coastal area means that voltage recovery following certain faults is inadequate to maintain proper voltage.

Other Transmission Solutions Considered
N/A

Why this Project was Selected as the Preferred Solution
Only viable solution

Jacksonville Static VAR Compensator (SVC)

- **NERC Category B Violations**
- **Problem:** Under certain faulted conditions DEP East's transmission network along the coast of NC would be unable to maintain adequate voltage support.
- **Solution:** Install a 300 MVAR 230 kV Static VAR Compensator (SVC) at the Jacksonville 230 kV Substation.



Project ID and Name: 0023 - Folkstone 230/115 kV Substation

Project Description
Construct the new Folkstone 230 kV Substation, loop-in the Castle Hayne - Jacksonville 230 kV line and connect to the Castle Hayne - Jacksonville City 115 kV line. This project will require the construction of approximately 16 miles of 115 kV and the installation of a 200 MVA 230/115 transformer.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	12/1/2012
Estimated Time to Complete	0 year
Estimated Cost	$19 M

Narrative Description of the Need for this Project
An outage of either of the Castle Hayne or Jacksonville terminals of the Castle Hayne-Jacksonville 115 kV line will cause voltage along the line to drop below planning criteria.

Other Transmission Solutions Considered
Reconductor existing line.

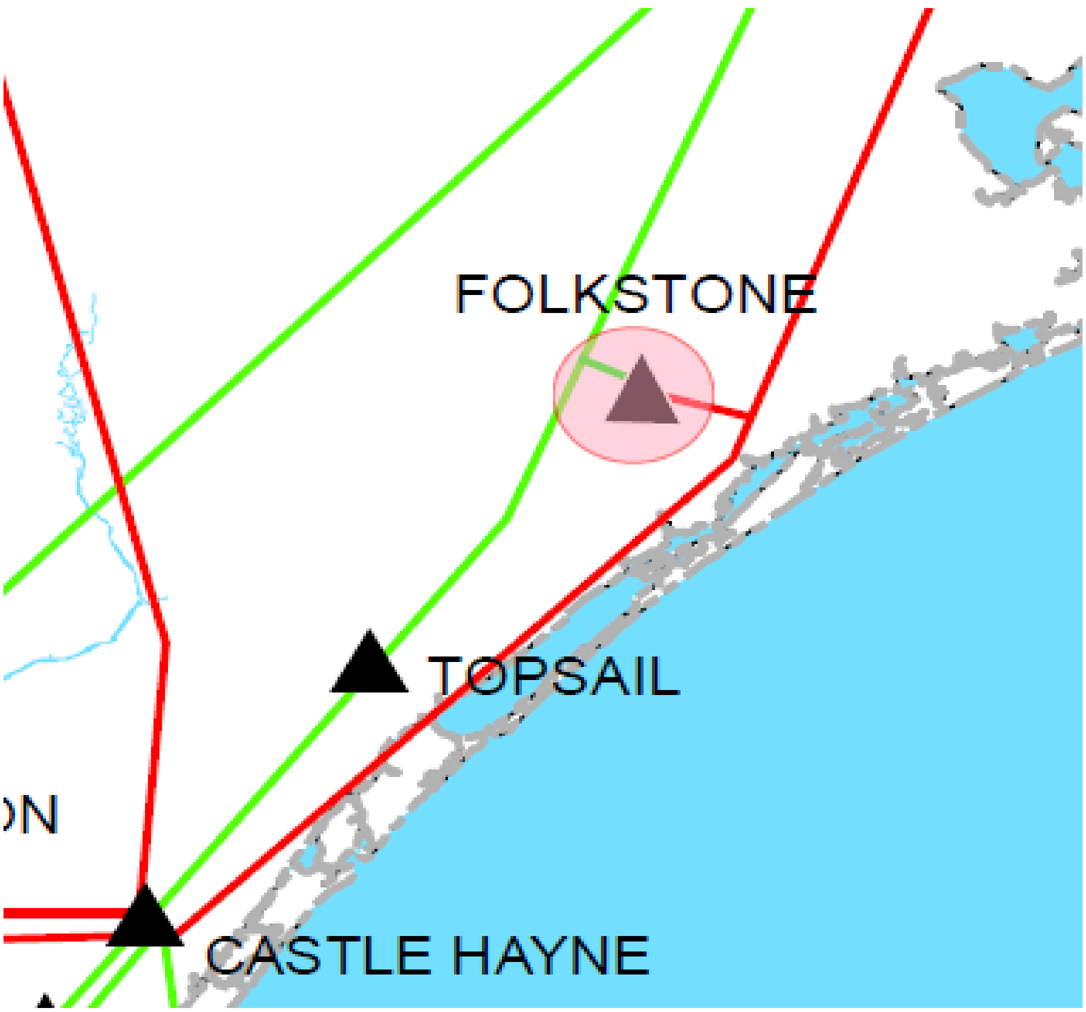
Why this Project was Selected as the Preferred Solution
Cost, feasibility, and long term effectiveness.

C-3

Folkstone 230/115 kV Substation

- **NERC Category B Violations**
- **Problem:** An outage of either of the Castle Hayne or Jacksonville terminals of the Castle Hayne-Jacksonville 115 kV line will cause voltage along the line to drop below planning criteria.

Solution: Construct the new Folkstone 230 kV Substation, loop-in the Castle Hayne - Jacksonville 230 kV line and connect to the Castle Hayne - Jacksonville City 115 kV line.



Project ID and Name: 0010A – Harris - RTP 230 kV Line

Project Description
Construct the Harris-RTP 230 kV Line. Develop RTP 230 kV Switching Substation at or near the existing Amberly 230 kV tap on the Cary Regency Park - Durham 230 kV line. Construct 7 miles of new 230 kV line between Amberly 230/23 kV and Green Level 115/23 kV using 6-1590 MCM ACSR and convert Green Level 115 kV Substation to 230/23 kV. Convert the existing Apex US 1 – Green Level 115 kV Feeder (approximately 7 miles) to 230 kV using 6-1590 MCM ACSR and remove the termination at Apex US #1. From the termination point removed at Apex US #1, continue with 4 miles of new 230 kV construction to the Harris 230 kV Switchyard using 6-1590 MCM ACSR.

Status	Underway: Engineering and Construction in progress.
Transmission Owner	DEP
Planned In-Service Date	6/1/2014
Estimated Time to Complete	1 year
Estimated Cost	$49 M

Narrative Description of the Need for this Project
This project is needed to serve rapidly growing load in the western Wake County area.

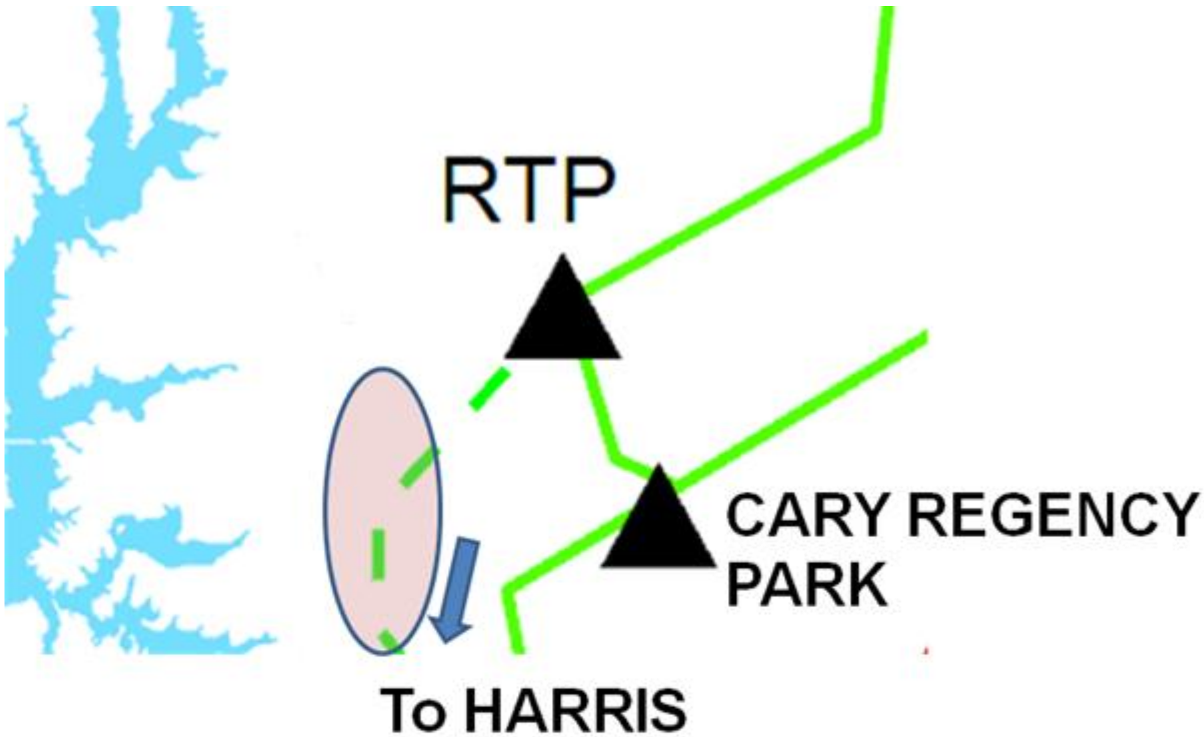
Other Transmission Solutions Considered
Construct Harris - Durham 230 kV line.

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

C-4

Harris - RTP 230 kV Line

- **Load Serving**
- **Problem:** This project is needed to serve rapidly growing load in the western Wake County area.
- **Solution:** Construct the Harris-RTP 230 kV Line.



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	6/1/2020
Estimated Time to Complete	4 years
Estimated Cost	$11 M

Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Folkstone – Jacksonville City 115 kV Line under the contingency of losing Folkstone – Jacksonville 230 kV Line. This project will mitigate each of these contingencies.

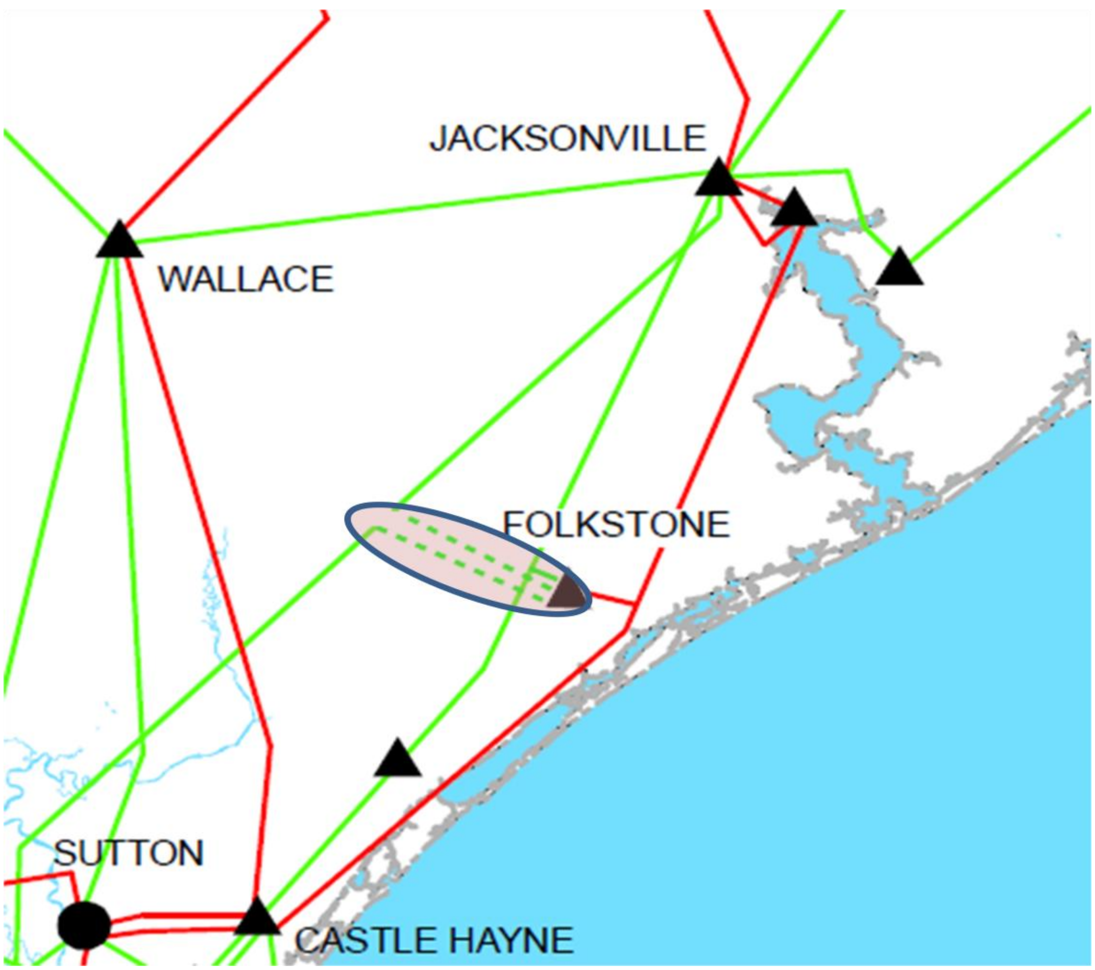
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

Why this Project was Selected as the Preferred Solution
Transmission system versus local fixes.

C-5

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

- **NERC Category B Violations**
- **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: 0008 – Greenville - Kinston DuPont 230 kV Line

Project Description
This project consists of constructing 30 miles of 230 kV line between Greenville and Kinston DuPont 230 kV Substations.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2014
Estimated Time to Complete	1 year
Estimated Cost	$32 M

Narrative Description of the Need for this Project
With a Brunswick unit down an outage of the Wilson - Greenville 230 kV line will cause the Greenville - (DVP) Everetts 230 kV line to exceed its rating.

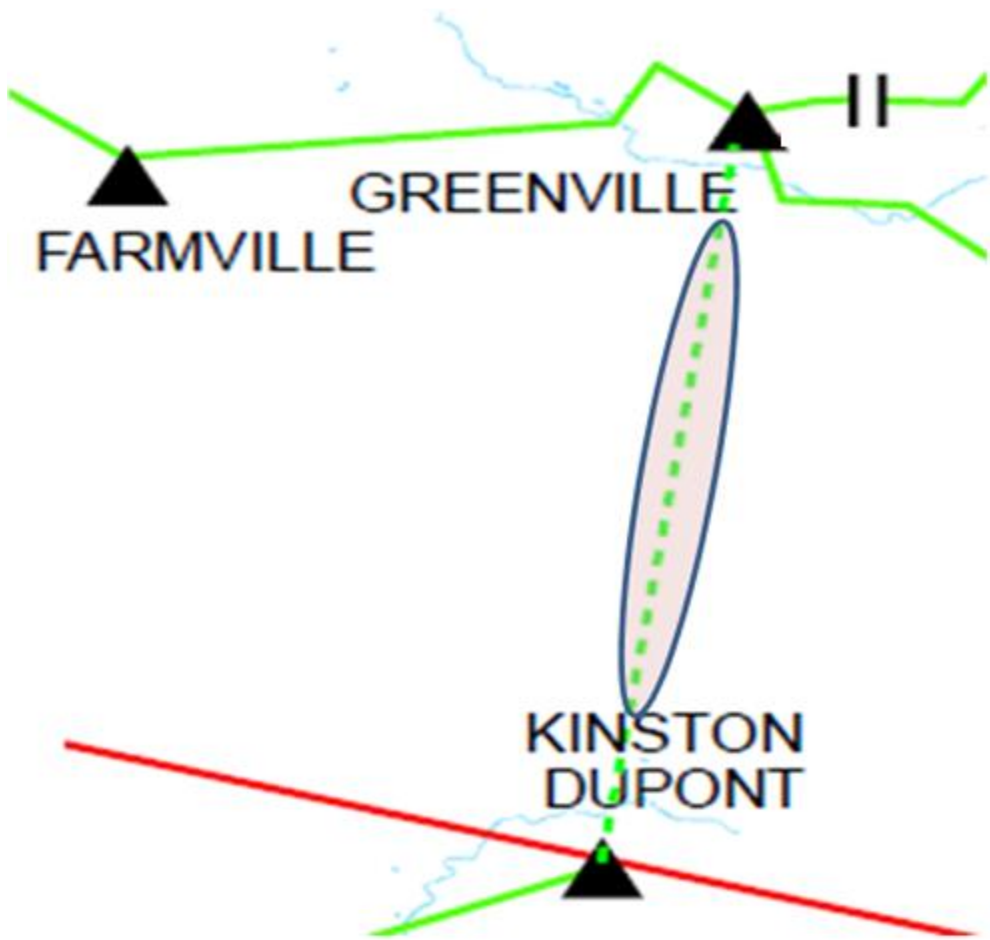
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

C-6

Greenville - Kinston DuPont 230 kV Line

- **NERC Category C Violations**
- **Problem:** With a Brunswick unit down an outage of the Wilson - Greenville 230 kV line will cause the Greenville - (DVP) Everetts 230 kV line to exceed its rating.
- **Solution:** Construct a 30 mile 230 kV line between Greenville and Kinston DuPont 230 kV Substations.
- **Note:** This project was originally scheduled to be completed 6/1/2017, but was accelerated to 6/1/2014 as part of the DEC - DEP merger mitigation projects.



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	4 years
Estimated Cost	$13 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.

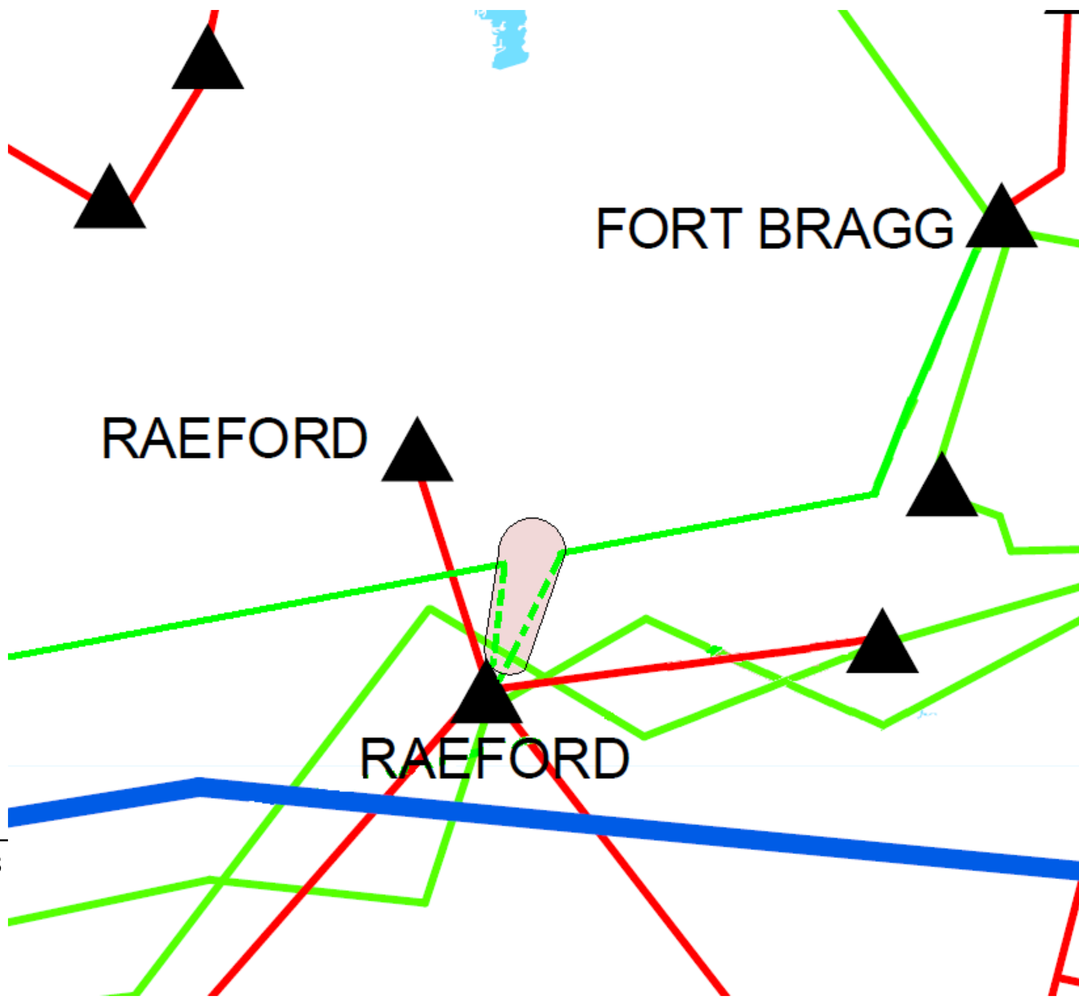
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

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

C-7

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

- **NERC Category C Violations**
- **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 replace the 200 MVA transformers with 300 MVA transformers**.**



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	6/1/2023
Estimated Time to Complete	4 years
Estimated Cost	$15 M

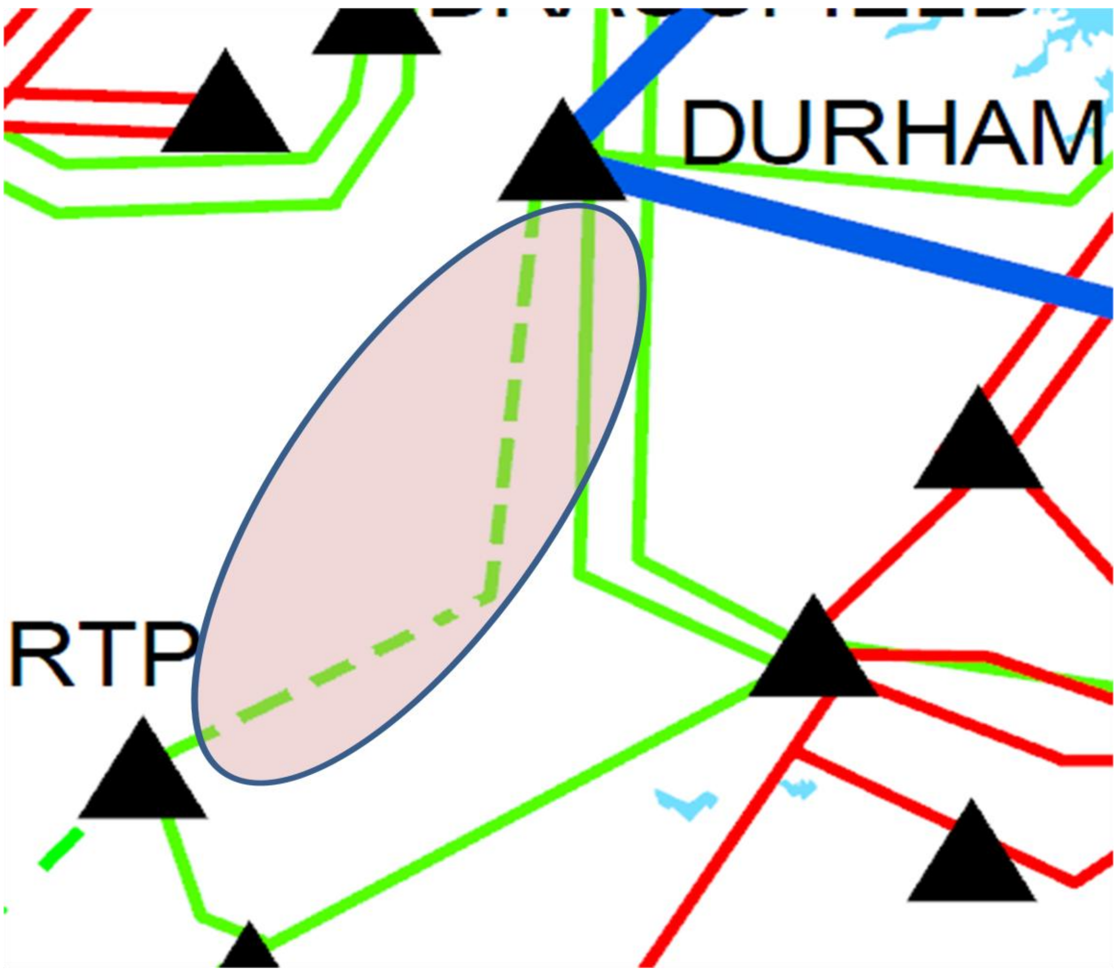
Narrative Description of the Need for this Project
With Harris Plant down, a common tower outage of the Method - (DPC) East Durham and the Durham - Method 230 kV Lines will cause an overload of the Durham 500 kV Sub - RTP 230 kV Switching Station Line.

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.

Durham-RTP 230 kV Line

- **NERC Category C Violations**
- **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: 0027 – Pisgah Tie - Shiloh Switching Station #1 & #2 230 kV Lines

Project Description
The project consists of reconductoring 22 miles of the existing 954 ACSR conductor with 1158 ACSS conductor.

Status	Construction underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2013
Estimated Time to Complete	0.5 years
Estimated Cost	$26 M

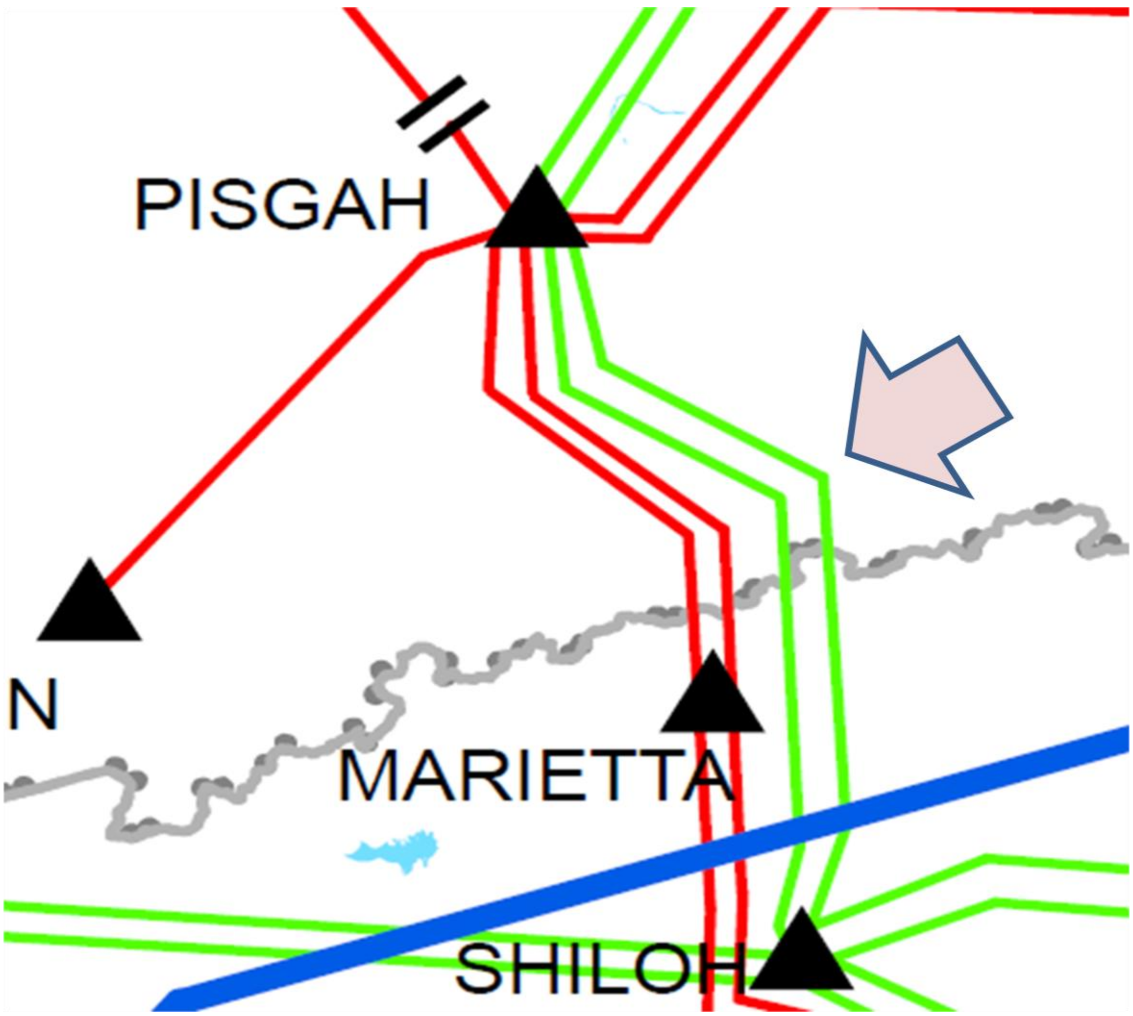
Narrative Description of the Need for this Project
The Caesar Lines would have achieved 100% of their conductor rating in the 2010 timeframe unless restrictions were made on transmission service to DEP West. The lines are most heavily loaded when there is high import into the DEP West area. For that reason, some transmission service on the DEC - DEP(CPLW) interface will have conditional firm status until the upgrades are completed.

Other Transmission Solutions Considered
Bundle the line. An additional tie line from DEC to DEP(CPLW)

Why this Project was Selected as the Preferred Solution
The high temperature conductor option has the lowest overall cost while meeting reliability requirements.

Pisgah Tie - Shiloh Switching Station #1 & #2 230 kV Lines

- **NERC Category B violation**
- **Problem:** The loss of one of the parallel 230 kV lines (Caesar) between Pisgah and Shiloh stations in NC/SC causes the thermal rating of the parallel line to be exceeded.
- **Solution:** Reconductor the 230 kV lines with 1158 ACSS.



Appendix C-2 Collaborative Transmission Plan Major Project Descriptions - **Merger 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 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: Lilesville-Rockingham 230 kV Line #3 Construct

Project Description
Construct approximately 14 miles of 1-2515 between Rockingham 230 kV Substation and Lilesville 230 kV Substation.

Status	Underway: Engineering and Construction in progress.
Transmission Owner	DEP
Planned In-Service Date	12/31/2013
Estimated Time to Complete	0.5 years
Estimated Cost	$14 M

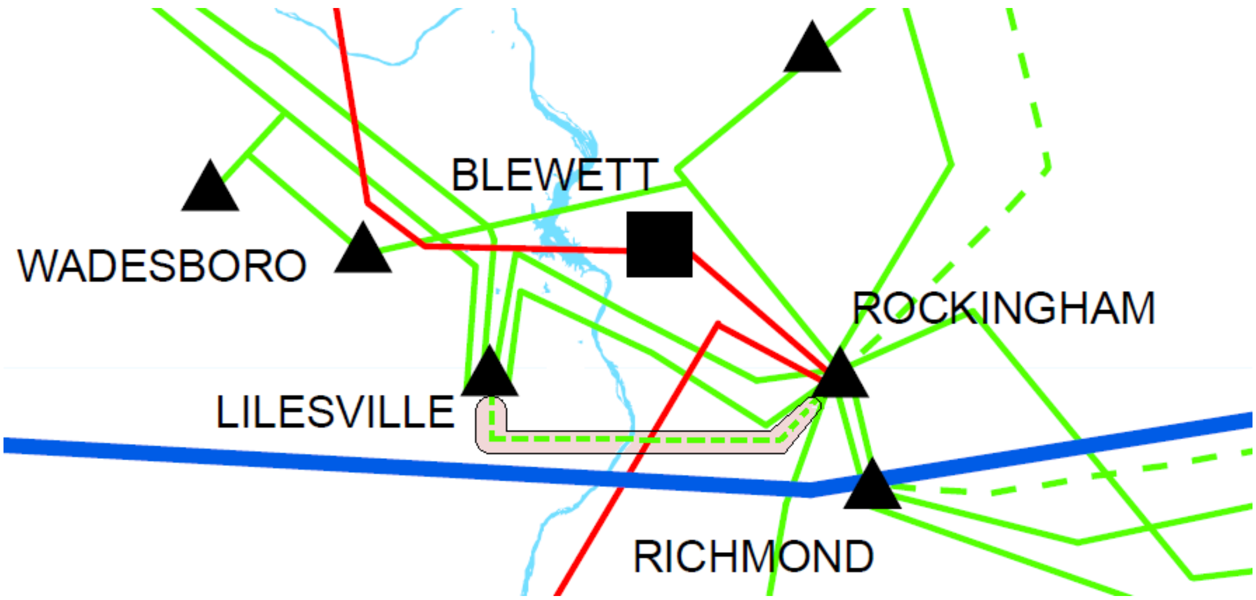
Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects.

Other Transmission Solutions Considered

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

Lilesville-Rockingham 230 kV Line #3 Construct

- **Project Description:** Construct approximately 14 miles of 1-2515 between Rockingham 230 kV Substation and Lilesville 230 kV Substation.



Project ID and Name: Person-(DVP) Halifax 230 kV Line Reconductor DVP Section (DVP work)

Project Description
Reconductor approximately 20 miles of 230 kV Line – Dominion portion.

Status	Underway: Engineering and Construction in progress.
Transmission Owner	Dominion
Planned In-Service Date	6/1/2014
Estimated Time to Complete	1 year
Estimated Cost	$21 M

Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects.

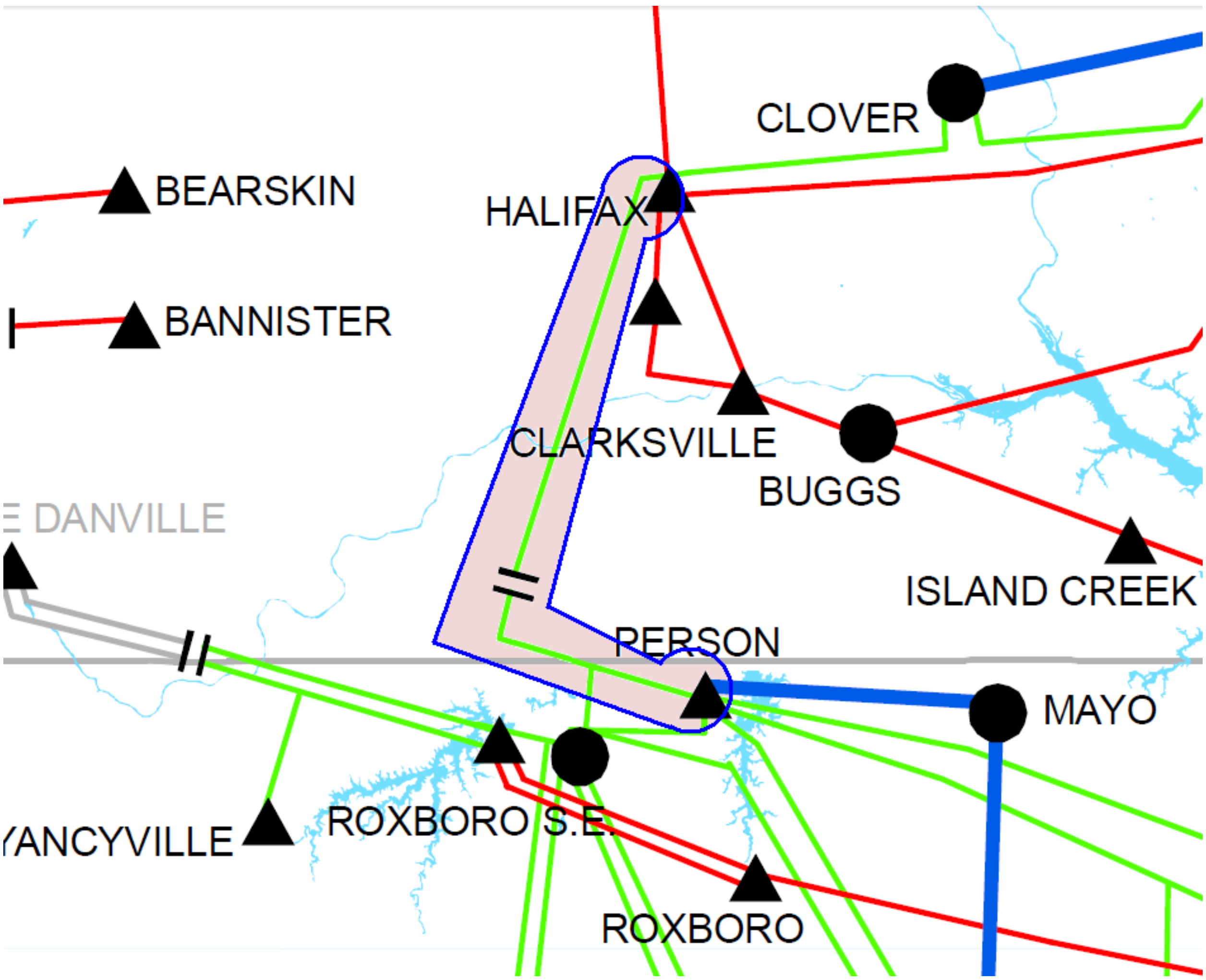
Other Transmission Solutions Considered

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

C-11

Person-(DVP) Halifax 230 kV Line Reconductor DVP Section (DVP work)

- **Project Description:** Reconductor approximately 20 miles of 230 kV Line – Dominion portion.



Project ID and Name: Antioch 500/230 kV Substation: Replace Two Transformer Banks

Project Description
Replace two transformer banks at the Antioch 500/230 kV Substation

Status	Underway: Engineering and Construction in progress.
Transmission Owner	DEC
Planned In-Service Date	6/1/2014
Estimated Time to Complete	1 year
Estimated Cost	$32 M

Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects

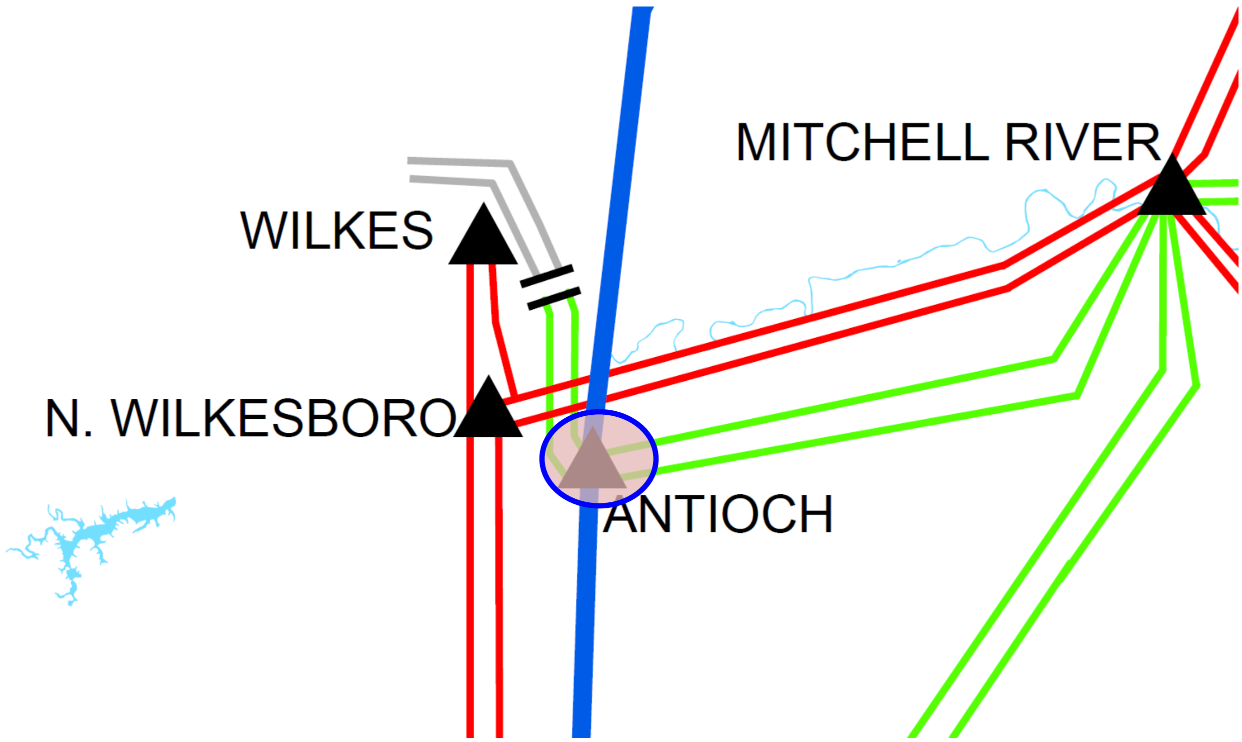
Other Transmission Solutions Considered

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

C-12

Antioch 500/230 kV Substation: Replace Two Transformer Banks

- **Project Description:** Replace two transformer banks at the Antioch 500/230 kV Substation.



Appendix D
Projects Investigated for 2023 Resource Supply Options

Resource Supply Option – 2023 Hypothetical Transfer Scenarios Studied											
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**PJM - DEC 1000 MW**		**SOCO - DEC 1000 MW**		**SCEG - DEC 1000 MW**		**SCPSA - DEC 1000 MW**	
				Date Needed[1]	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**
Bush River-Georgia Pacific (SCEG) 115 kV and Bush River-White Rock (SCEG) 115 kV, upgrade	Lines overload for loss of Bush River 230 kV line	DEC	3	-	-	-	-	2023	16	2023	16

1 The tables in Appendix D reflect the date the project is needed in order to implement the resource supply option studied.

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.

Resource Supply Option – 2023 Hypothetical Transfer Scenarios Studied											
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**DEP(CPLE) - DEC 1000 MW**		**TVA - DEC 1000 MW**		**PJM - DEP(CPLE) 1000 MW**		**SCEG - DEP(CPLE) 1000 MW**	
				Date Needed[1]	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**
Bush River-Georgia Pacific (SCEG) 115 kV and Bush River-White Rock (SCEG) 115 kV, upgrade	Lines overload for loss of Bush River 230 kV line	DEC	3	-	-	-	-	-	-	2023	16

1 The tables in Appendix D reflect the date the project is needed in order to implement the resource supply option studied.

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.

Resource Supply Option – 2023 Hypothetical Transfer Scenarios Studied											
Primary Alternative Investigated	Issue Identified	TO	Lead Time (years)	SCPSA - DEP(CPLE) 1000 MW		DEC - DEP(CPLE) 1000 MW		DEC - SOCO 1000 MW		PJM - DEC/DEP(CPLE) 1000 MW	
				Date Needed[1]	($M)[2]	Date Needed[1]	($M)[2]	Date Needed[1]	($M)[2]	Date Needed[1]	($M)[2]
-	-	-	-	-	-	-	-	-	-	-	-

1 The tables in Appendix D reflect the date the project is needed in order to implement the resource supply option studied.

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.

Resource Supply Option – 2023 Hypothetical Transfer Scenarios Studied											
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**DEC - DEP(CPLE)/PJM 1000 MW**		**DEP(CPLE) - PJM 1000 MW**		**DEC - PJM 1000 MW**		**SOCO - PJM 1000 MW**	
				Date Needed[1]	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**
-	-	-	-	-	-	-	-	-	-	-	-

1 The tables in Appendix D reflect the date the project is needed in order to implement the resource supply option studied.

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 ≥ $10M)									
				2012 Plan[1]			2013 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0026	Brunswick 1 - Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing	Address loading on the Sutton Plant - Castle Hayne 230 kV Line.	DEP	Underway	12/31/2012	27	In-Service	3/3/2013	27
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high transfers	DEP	Underway	6/1/2013	32	In-Service	5/14/2013	32
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	DEP	Underway	12/1/2012	19	In-Service	12/1/2012	19
0010A	Harris Plant - RTP 230 kV Line, Establish a new 230 kV line by utilizing the Amberly 230 kV Tap, converting existing Green Level 115 kV Feeder to 230 kV operation, Construction of new 230 kV line, remove 230/115 kV transformation and connection at Apex US1	Address the need for new transmission source to serve rapidly growing load in the western Wake County area; helps address loading on Cary Regency Park - Durham 230 kV line	DEP	Underway	6/1/2014	59	Underway	6/1/2014	59

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2012 Plan[1]			2013 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV Substation	Address loading on Folkstone – Jacksonville City 115 kV Line.	DEP	Planned	6/1/2020	14	Planned	6/1/2020	11
0008	Greenville - Kinston DuPont 230 kV Line, Construct line	Address loading on Greenville - Everetts 230 kV Line and meet merger commitment	DEP	Planned	6/1/2014	34	Underway	6/1/2014	32
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	14	Planned	6/1/2018	13
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham-RTP 230 kV Line	DEP	Planned	6/1/2022	15	Planned	6/1/2023	15

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2012 Plan[1]			2013 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0027	Reconductor Caesar 230 kV Lines (Pisgah Tie - Shiloh Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line during high imports to DEP West.	DEC	Underway	6/1/2013	26	Underway	12/1/2013	26
0014	Reconductor London Creek 230 kV Lines (Peach Valley Tie - Riverview Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line when a 230 kV connected Oconee unit is off line.	DEC	Planned	6/1/2017	48	Removed	-	-
0011	Asheville - Enka, Convert 115 kV Line to 230 kV, Construct new 115 kV line	Address Asheville 230/115 kV transformer loading	In-Service	DEP	12/1/2010 12/1/2012	30			
TOTAL						**318**			**234**

NCTPC Update on Merger Projects – (Estimated Cost ≥ $10M)									
				2012 Plan[1]			2013 Plan		
Project ID	Merger Project	Issue Resolved	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
M-0001	Lilesville-Rockingham 230KV Line #3 – Construct new line	This project is part of the DEC - DEP merger mitigation projects.	DEP	Underway	6/1/2014	15	Underway	12/31/2013	14
M-0002	Person-(DVP) Halifax 230kV Line - Reconductor DVP Section (DVP work)	This project is part of the DEC - DEP merger mitigation projects.	DEP/ Dominion	Underway	6/1/2014	16	Underway	6/1/2014	21
M-0003	Antioch 500/230kV Substation: Replace Two Transformer Banks	This project is part of the DEC - DEP merger mitigation projects.	DEC	Underway	6/1/2014	28	Underway	6/1/2014	32
TOTAL						**59**			**67**

[1] Information reported in Appendix B of the NCTPC 2012 - 2022 Collaborative Transmission Plan" dated January, 17, 2013.

[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 2012 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2013 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.

[4] This project was originally scheduled to be completed 6/1/2017, but was accelerated to 6/1/2014 as part of the DEC - DEP merger mitigation projects.

Appendix F
Acronyms

ACRONYMS

ACSR	Aluminum Conductor Steel Reinforced
ACSS	Aluminum Conductor, Steel Supported
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
ETAP	Enhanced Transmission Access Planning
EU2	Energy United
FSA	Facilities Study Agreement
ISA	Interconnection Service Agreement
kV	Kilovolt
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
NC	North Carolina
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
NHEC	New Horizons Electric Cooperative
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
RETP	Regional Economic Transmission Plan
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
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas Reliability Agreement
VAR	Volt Ampere Reactive