North Carolina Transmission Planning Collaborative

Report on the NCTPC 2021 Public Policy Study

May 9, 2022
DRAFT REPORT

2021 NCTPC Public Policy Study

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I. Executive Summary

Each year, the Oversight Steering Committee (OSC) of the North Carolina Transmission Planning Collaborative (NCTPC) will determine if there are any public policies that may drive the need for local transmission projects. Through this process, the OSC will seek input from Transmission Advisory Group (TAG) participants, as well as from members of the OSC itself, to identify any public policies to be evaluated as part of the Local Planning Process. The OSC will use the criteria below to determine if there are any public policies that may drive the need for local transmission upgrades:

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

A Public Policy Study request was submitted in January 2021 by the NCUC Public Staff, requesting the study of a number of hypothetical scenarios involving accelerated retirement of coal generation, increased onshore and offshore wind generation, and increased solar generation. The 2021-2031 Collaborative Transmission Plan ("2021 Plan") was published in January 2022. The analysis of the Public Policy Study request was not completed in time for inclusion in the 2021 Plan. The Public Policy Study request results have now been completed and are provided in this supplemental report.

North Carolina House Bill 951 ("HB 951") has generated significant interest across a wide range of stakeholders; however, the public policy scenario that was studied as part of the 2021 NCTPC cycle was developed prior to the passage of HB 951 and is not intended to be a determination of transmission upgrades required to satisfy the requirements of the HB 951 Carbon Plan. Furthermore, while this public policy study may inform NCTPC of potential transmission projects, it does not replace the official processes for evaluating future resources. For example, new generation resources in DEC and DEP are evaluated as Generator Interconnection requests, and new resources sinking in, sourcing from, or wheeling through DEC and/or DEP are evaluated as Transmission Service requests. While the results of this study and previous studies can be used to shape future public policy study requests, understand potential transmission impacts, and inform the NCTPC of potential transmission projects the results should be understood as being based on one or more hypothetical scenarios that may not align with future resource assumptions.

Table 1 below provides a summary of reliability projects identified by this Public Policy Study request.

Table 1. Reliability Projects Identified for 2021 Public Policy Study

Reliability Project	Mileage	Estimated Cost ($M)
Upgrade Bannertown 100 kV Lines (Bannertown Tie-Mitchell River Tie)	18.7	63.6
Upgrade Kennedy 100 kV Lines (Newton Tie-Orchard Tie)	4.2	14.3
Upgrade Lee 100 kV Lines (Lee Steam Station-Shady Grove Tie)	9.8	45
Upgrade Piedmont 100 kV Lines (Lee Steam Station-Shady Grove Tie)	9.6	45
Upgrade Wateree 100 kV Lines (Great Falls Switching Station-Wateree Tie)	19.8	67.4
Reconductor Fayetteville-Hope Mills Church St. section of the Fay-Fay Dupont 115 kV line	4.9	11.6
Raise Dillon Tap-Marion section of the Weatherspoon – Marion 115 kV Line to 212 F Rating	14.6	6.9
Shaw AFB-Eastover section of Sumter – DESC Eastover 115kV Tie Line. Working with DESC to get higher line rating.	7.3	n/a
Replace New Bern Transformers to 336 MVA Banks	-	8.0
Upgrade Bus tie breaker to 3000A at New Bern 230 kV Substation	-	2.0
Uprate entire Kinston Dupont-New Bern 115 kV Line to 212 F Rating	29.6	14.8
Uprate entire Havelock-New Bern 230 kV Line to 212 F Rating. Change CT ratio at Havelock.	23.5	23.5
Uprate two sections of Aurora-New Bern 230 kV Line to 212 F Rating	8.5	8.5
Reconductor both sections of New Bern-Wommack 230 kV North Line	32	96.0
Estimated Cost Total		**406.6**

Please note that this public policy study included a proposed level of incremental solar but did not receive guidance regarding the geographic and electrical location of these hypothetical solar facilities. This may affect the location of the specific upgrades necessary to support additional incremental solar generation. Furthermore, this public policy study did not look at different dispatch scenarios that could indicate the need for additional local transmission projects under these credible generation dispatch scenarios.

II. 2021 Public Policy Study Scope and Methodology

II.A. Assumptions

The following assumptions were made for the 2021 Public Policy study:

- Accelerated Retirement of Coal Generation
  - Allen 1-5 (DEC), 1082 MW total
  - Belews Creek 1-2 (DEC)[1], 2257 MW total
  - Cliffside 5 (DEC), 574 MW
  - Marshall 1-4 (DEC)[2], 2194 MW total
  - Mayo 1 (DEP), 704 MW
  - Roxboro 1-4 (DEP), 2439 MW total
- Increased Wind Generation
  - 2500 MW of onshore wind resources in the Midwest
    - 1500 MW exported from the Midwest to DEC
    - 1000 MW exported from the Midwest to DEP
  - 1600 MW of offshore wind resources interconnected at DEP's New Bern 230 kV Substation
    - 1000 MW exported from DEP to DEC

[1] Dual fuel optionality is assumed to allow 50% of existing output for both units to remain but fire on natural gas.

[2] Dual fuel optionality is assumed to allow 50% of existing output for units 3 and 4 to remain but fire on natural gas.

        - 600 MW remains in DEP
    - 2640 MW of offshore wind resources interconnected at Dominion Energy Virginia (DEV's) Fentress 500 kV Substation
        - Other DEV generation was scaled down by 2640 MW
- Increased Solar Generation
    - Additional 3000 MW in DEC
    - Additional 1500 MW in DEP
    - 568 MW of battery storage at DEP's Mayo 500 kV Substation
- A hypothetical Combined Cycle at Roxboro was included in the study scope but excluded from the study since it was not needed to serve load in this specific scenario.

II.B. Case Development

Two cases were developed to study this Public Policy request. Both cases were based off a 2031 Summer Peak Model. The details of Case 1 (on-peak load) & Case 2 (off-peak load) are provided below:

Case 1 was an on-peak load case. The load was set to 100% summer peak load. The previous coal retirements specified in the Assumptions section of this report were made. Based on historical performance data, solar was set to 80% of nameplate for DEC and to 50% of nameplate for DEP. Based on the potential for wind resources to peak at any time of the day, offshore wind and onshore wind were set to 100% of nameplate. A 568 MW battery was placed at Mayo and was discharging at 100% of rated output in this case. The remaining generating units in each Balancing Authority Area (BAA) were economically dispatched after the additional renewable generation was added and the coal units were retired.

Case 2 was an off-peak load case. The load was set to 75% summer peak load for DEC and 83% summer peak load for DEP. The purpose of this case was to model DEC/DEP solar (existing and incremental) consistent with typical output across mid-day/early afternoon conditions (100% of solar nameplate). The difference in load level assumptions for DEC and DEP (75% versus 83%) is due to the high additional renewable generation with lower load in DEP and the desire to maintain must run status for DEP nuclear generation. The must run status for DEP nuclear generation requires these nuclear units to be run at maximum output to avoid reliability concerns. The excess renewable generation seen in this case for DEP, even with the Mayo battery charging, could point to the need for additional storage or curtailment in future high renewable studies when looking at different load levels. The previous coal retirements specified in the Assumptions section of this report were made. Based on the potential for wind resources to peak at any time of the day, offshore wind and onshore wind were set to 100% of nameplate. A 568 MW battery was placed at Mayo and was charging at 100% of rated output in this case. The remaining generating units in each BAA were economically dispatched after the additional renewable generation was added and the coal units were retired.

Unless otherwise noted, retirements and generation mix in external systems is reflective of the 2020 Multiregional Modeling Working Group (MMWG) series of cases.

II.C. Study Methodology

The study results are based on a power flow analysis of a 2031 summer model of on-peak and off-peak load conditions.

The on-peak and off-peak cases contained all of the same assumptions for renewable generation, load, coal retirements, and storage in the same model. The study did not include dispatches that max out local study area generation.

The study results are focused exclusively on DEC and DEP. Potential impacts to external systems must be evaluated through the Affected System Study process.

II.D. DEC Results

Several transmission upgrades beyond what was included in the 2021 Plan were identified on the DEC system:

- The upgrade of the Bannertown 100 kV lines is driven by generation retirements at Belews Creek combined with additional solar that was included on the Bannertown 100 kV lines.
- The upgrade of the Kennedy 100 kV lines is driven by additional solar that was included in the local area.
- The 2021 Plan includes an upgrade of the Monroe 100 kV lines (Lancaster-Monroe). This area of the system has seen a reasonably high level of queue activity, and future generation in the local area will be able to utilize the additional transmission capacity that will result from the upgrade. As such, this area of the system was assumed to be a potential location for future solar. The increased generation that was modeled in this area of the system drove the need to upgrade the Wateree 100 kV lines.
- In this study, the upgrades of the Lee 100 kV lines and the Piedmont 100 kV lines are driven by a combination of non-peak load study conditions, high renewable integration across the system, and less online generation in the central part of DEC's system.

Table 2. DEC Reliability Projects Identified for 2021 Public Policy Study

Reliability Project	Mileage	Estimated Cost ($M)
Upgrade Bannertown 100 kV Lines (Bannertown-Mitchell River)	18.7	63.6
Upgrade Kennedy 100 kV Lines (Newton-Orchard)	4.2	14.3
Upgrade Lee 100 kV Lines (Lee-Shady Grove)	9.78	45
Upgrade Piedmont 100 kV Lines (Lee-Shady Grove)	9.62	45
Upgrade Wateree 100 kV Lines (Great Falls-Wateree)	19.8	67.4
DEC Estimated Total Cost		**235.3**

II.E. DEP Results

The following represents DEP Reliability Projects identified as a result of the 2021 Public Policy Study.

- The Fayetteville-Hope Mills Church Street section of the Fayetteville-Fayetteville Dupont 115 kV line is an upgrade that has been assigned to the cluster study.
- The Dillon Tap–Marion up-rate is an upgrade that has been assigned to the cluster study.
- The Shaw AFB–Eastover section of the tie line is a previously observed issue in the DEP TPL-001 Annual System Screening Study. DEP is actively working with DESC to get a higher line rating.

Table 3. DEP Reliability Projects Identified for 2021 Public Policy Study

Reliability Project	Mileage	Estimated Cost ($M)
Reconductor Fayetteville-Hope Mills Church St. section of the Fay-Fay Dupont 115 kV line	4.9	11.6
Raise Dillon Tap-Marion section of the Weatherspoon–Marion 115 kV Line to 212 F Rating	14.6	6.9
Shaw AFB-Eastover section of Sumter–DESC Eastover 115 kV Tie Line. Working with DESC to get higher line rating.	7.3	n/a
Table 3 DEP Estimated Total Cost		**18.5**

New Bern-Area Results

All upgrades identified in Table 4 below are in the New Bern area. The addition of 1600 MW Net Generation at the New Bern 230 kV Substation is the primary driver of these upgrades. The cost to bring generation into New Bern through an underground cable or other transmission was not evaluated in this study.

Table 4. New Bern Area DEP Reliability Projects Identified for 2021 Public Policy Study

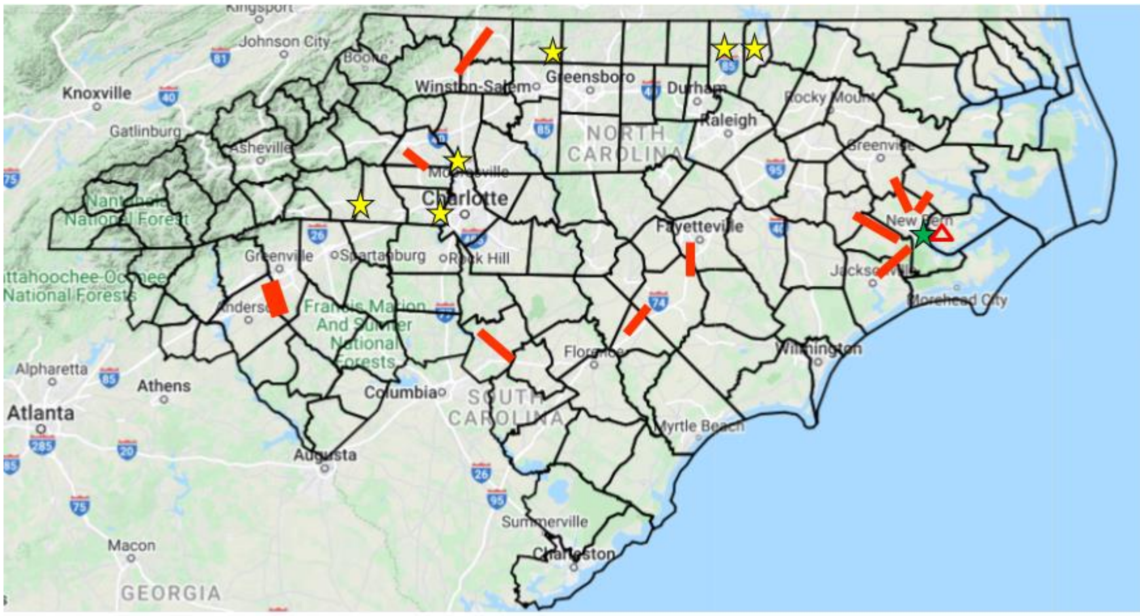
Reliability Project	Mileage	Estimated Cost ($M)
Replace New Bern Transformers to 336 MVA Banks	-	8.0
Upgrade Bus tie breaker to 3000A at New Bern 230 kV Substation	-	2.0
Uprate entire Kinston Dupont-New Bern 115 kV Line to 212 F Rating	29.6	14.8
Uprate entire Havelock-New Bern 230 kV Line to 212 F Rating. Change CT ratio at Havelock.	23.5	23.5
Uprate two sections of Aurora-New Bern 230 kV Line to 212 F Rating	8.5	8.5
Reconductor both sections of New Bern-Wommack 230 kV North Line	32	96.0
Table 4 DEP Estimated Total Cost		**152.8**

II.F. Summary of Results

Table 5: Cost Summary

Area	Estimated Cost ($ M)
DEC	$235.3 M
DEP	$171.3 M
Total	**$406.6 M**

Figure 1: Locations of Coal Retirements, Offshore Wind Injection and Transmission Upgrades Associated with 2021 Public Policy Study



Map Legend:

- **Green Stars are new generation (added offshore wind for DEP)**
- **Yellow Stars are retired coal generation sites**
- **Red triangle is a transformer upgrade**
- **Remaining red line segments are line upgrades (uprates and reconductors)**

II.G. Study Limitations

HB 951 has generated significant interest across a wide range of stakeholders; however, the public policy scenario that was studied as part of the 2021 NCTPC cycle was developed prior to the passage of HB 951 and is not intended to be a determination of transmission upgrades required to satisfy the requirements of the HB 951 Carbon Plan. Furthermore, this public policy study does not replace the official processes for evaluating future resources. For example, new generation resources in DEC and DEP are evaluated as Generator Interconnection requests, and new resources sinking in, sourcing from, or wheeling through DEC and/or DEP are evaluated as Transmission Service requests.

While the results of this study and previous studies can be used to shape future public policy study requests, understand potential transmission impacts, and inform the NCTPC of potential transmission projects, the results should be understood as being based on one or more hypothetical scenarios that may not align with future resource assumptions. For example, this Public Policy study included a proposed level of incremental solar but did not receive guidance regarding the geographic and electrical location of these hypothetical solar facilities.

As previously stated, the 2021 Public Policy Study is meant to be an initial approach into looking at the transmission necessary for a high renewable future scenario. However, this study does have limitations and further analysis would be needed to identify all upgrades necessary to accommodate HB 951 or other future scenarios associated with the Carbon Plan. Some of these limitations are described below. DEC and DEP both now utilize a cluster study approach for Generator Interconnections. This study only looked at a 2031 Summer year. Power flow was the only analysis run for this study. Stability and short circuit analyses were outside the scope of the study and could result in additional upgrades. The results are also focused on DEC and DEP. Unless otherwise noted, retirements and generation mix in external systems is reflective of 2020 MMWG series of cases. The affected system process evaluates impacts to external systems.

While public policy studies can inform us of potential future projects it does not replace the need for individual resources to be evaluated through the Generator Interconnection Request and/or Transmission Service Request processes. Furthermore, the results of the public policy studies may differ from other transmission studies due to factors such as generation dispatches and contingencies that are evaluated in other transmission studies to meet the NERC TPL-001-4 requirements but may not be evaluated in public policy studies.

III. Conclusions

The conclusions of this study are driven by the assumptions used for the study. It is important to remember that this study considered one specific year at two load levels, and this study only evaluated a limited number of dispatches. To fully understand the impacts of this public policy scenario and different future scenarios, additional studies are required. This may involve evaluating solar and wind separately to see how each affects the study, which could produce additional upgrades. Resources assumed for this study that have yet to be approved will require a Generator Interconnection Request and/or a Transmission Service Request. Both of those study processes have considerations that are beyond what was consider for this study.

DEC and DEP have successfully integrated or procured over 5 GW of renewables and remain committed to increasing this amount. With additional renewable integration in the Carolinas, transmission upgrades will be required to keep pace and to reliably operate the systems. The scope of these upgrades will be tied to the size and location of future resources, which underscores the need to understand the most probable locations for future solar and wind resources and the expected level of renewable integration. Several areas of the DEC and DEP systems have previously been identified as potentially constrained due to the level of renewables that have already been integrated and/or proposed in those areas. Other areas of the system that have not yet been identified as potentially constrained might be well-suited from a transmission perspective depending on the size and location of future resources.