INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Tuesday, September 20, 2022
TIME: 9:34 a.m. – 12:46 p.m.
DOCKET NO(s): E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plans and Carbon Plan

VOLUME NUMBER: 17

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

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DATE: Tuesday, September 20, 2022

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DOCKET NO.: E-100, Sub 179

BEFORE: Chair Charlotte A. Mitchell, Presiding

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Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and

Duke Energy Carolinas, LLC,

2022 Biennial Integrated Resource Plans

and Carbon Plan

VOLUME: 17

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

I/A

Avangrid Renewables LLC
Transmission Panel Direct Cross-Examination
Exhibit No. 1

North Carolina Transmission Planning Collaborative

Report on the NCTPC 2020 Offshore Wind Study

June 7, 2021
FINAL REPORT

2020 – 2030 NCTPC Offshore Wind Study
Table of Contents

I. Executive Summary

The 2020-2030 Collaborative Transmission Plan (the “2020 Collaborative Transmission Plan” or the “2020 Plan”) was published in January 2021. This addendum documents the offshore wind study performed in response to a Local Public Policy Request.

The Southeastern Wind Coalition (SEWC) requested a study of the feasibility and costs of injecting up to 5000 MW of offshore wind power at up to 3 sites in eastern DEP, or possibly connecting to and wheeling offshore wind power from Dominion Virginia Power (Dominion, DVP). The power from the offshore wind plants would be delivered 40% to DEP and 60% to DEC. Rather than studying pre-determined MW levels, SEWC requested that NCTPC find the MW breakpoints at which transmission upgrades would be needed.

The offshore wind study started with the 2030 summer peak base case prepared for the 2020 NCTPC studies. The planned 2640 MW Dominion offshore wind plant was then added to the Dominion Fentress 500kV bus, dispatched against existing Dominion generation. No other generation from the DEC, DEP, or PJM generator interconnection queues was added. These generator interconnection queues contain thousands of MW of possible generation that may or may not actually interconnect and which could significantly affect the flows on the DEC, DEP, and Dominion transmission systems in unknown ways. The results of this study could change significantly depending on which and how much generation in those queues moves forward to interconnection.

The focus of this offshore wind study was to estimate the amount of generation that could be injected at various locations in eastern part DEP, within a reasonable distance from the Atlantic coast, and transmitted to DEP and DEC customers. The initial screening list of injection points included 29 major transmission substations and switching stations in eastern DEP as well as two stations in Dominion. Later in the process, another possible future DEP station, Sutton North, was added to the list. Linear transfer capability analysis was performed for each injection station, sending the injected power 60% to DEC and 40% to DEP. Basic transmission upgrades and their costs were estimated for transmission limits encountered. Transfer analysis and transmission upgrade estimation were repeated for each site until costs per injected MW escalated beyond reasonable levels. This screening analysis of 32 sites is described in Section II, with details shown in Appendix A.

Based on the results of screening the 32 sites, the three preferred sites chosen for analysis at higher levels of offshore wind power injection were:

- New Bern 230kV
- Greenville 230kV
- Sutton North 230kV

The first two are existing DEP stations and the last, Sutton North, is a proposed future DEP 230kV switching station.

Based on system knowledge and the 2012 offshore wind study results, and the goal to inject 1000s of MW of offshore wind power at each site, 500kV transmission lines were added to connect each of the three preferred sites to the existing DEP 500kV transmission system further inland. These upgrades are necessary to carry significant power from the coast, where DEP has only moderate amounts of customer load, to DEP's major load center in the Raleigh, NC area.

The results of this study showed that 100s of MW of offshore wind generation can be injected at numerous substations in eastern DEP with moderate upgrades, up to around 1000 MW or so at some sites, again with moderate upgrades (less than $100M). Table 1 summarizes the best cost per Watt found at the 32 sites screened. Network upgrade costs as well as cost estimates for interconnection lines from the beach landing to the DEP substation are included in Total Cost. Costs of undersea cables to bring power from the offshore wind farm site to the beach landing are not included.

Note that the results for the two Dominion buses (Fentress 500 kV and Landstown 230 kV) do not include any possible required upgrades in the Dominion system nor any wheeling fees[1]. Recent PJM interconnection studies have found significant transmission overloads for generation sites in southeastern Dominion.

[1] PJM wheeling fees were $63,045/(MW-year) as of 10/31/2020. For the approximately 2300 MW injection level shown in Table 1 for Dominion buses, PJM wheeling fees would total $2.9 billion over 20 years. This wheeling rate is subject to change.

Table 1. Best Cost per Watt Found at 32 Sites Screened

Point of Interconnection	MW Injection	Total Cost ($M)	Total Cost ($/W)
Fentress 500 (DVP)	2307	$ 100	$ 0.04[2]
Landstown 230 (DVP)	2257	$ 65	$ 0.03[3]
Cumberland 500	1700	$ 380	$ 0.22
Cumberland 230	1461	$ 375	$ 0.26
Wake 230	1458	$ 464	$ 0.32
New Bern 230	1449	$ 181	$ 0.12
Wommack 230	1432	$ 259	$ 0.18
Wake 500	1417	$ 460	$ 0.32
Lee 230	1151	$ 360	$ 0.31
Greenville 230	1106	$ 425	$ 0.38
Jacksonville 230	1049	$ 118	$ 0.11
Delco 230	1036	$ 183	$ 0.18
Castle Hayne 230	994	$ 34	$ 0.03
Grants Creek 230	966	$ 79	$ 0.08
Florence 230	911	$ 400	$ 0.44
Marion 230	876	$ 288	$ 0.33
Havelock 230	859	$ 20	$ 0.02
Clinton 230	853	$ 321	$ 0.38
Kinston Dupont 230	851	$ 154	$ 0.18
Weatherspoon 230	788	$ 302	$ 0.38
Whiteville 230	770	$ 175	$ 0.23
Sutton North 230	833	$ 117	$ 0.14

[2] PJM network upgrades and wheeling fees not included.

[3] PJM network upgrades and wheeling fees not included.

Point of Interconnection	MW Injection	Total Cost ($M)	Total Cost ($/W)
Kingstree 230	667	$ 225	$ 0.34
Mt. Olive 230	637	$ 312	$ 0.49
Sumter 230	558	$ 375	$ 0.67
Morehead Wildwood 230	550	$ 27	$ 0.05
Wallace 230	548	$ 160	$ 0.29
Aurora 230	544	$ 230	$ 0.42
Folkstone 230	518	$ 7	$ 0.01
Latta 230	425	$ 265	$ 0.62
Brunswick 1 230	387	$ 26	$ 0.07
Brunswick 2 230	277	$ 30	$ 0.11

Injecting 2000 to 3000 MW or more at any location in DEP will require larger transmission investments at the 500kV voltage level, costing approximately $900M to $2.0B depending on location and MW injection level. For the three sites studied at higher MW injection levels, Table 2 shows the selected injection levels found with and without construction of 500kV lines.

Injecting 5000 MW at a single site was not found to be feasible, but equivalent total injection at multiple sites might be. However, simultaneous injections at multiple sites were not analyzed in this study.

This study estimated transmission infrastructure needed only in the Duke Energy regions. The Greenville site in particular would require an Affected System Study by PJM that could result in significant additional upgrade costs.

Table 2. Selected Injection Levels at Preferred Sites

Point of Interconnection	MW Injection	Total Cost ($M)	Total Cost ($/W)
Without 500 kV Additions			
New Bern 230 *kV*	1449	$ 181	$ 0.12
Greenville 230 *kV*	1106	$ 425	$ 0.38
Sutton North 230 *kV*	1217	$ 355	$ 0.29
Build New Bern - Wommack - Wake 500 kV lines			
New Bern 500 *kV*	3252	$ 1,177	$ 0.36
Build Greenville - Wommack - Wake 500 kV lines			
Greenville 230 *kV*	3587	$ 2,010	$ 0.56
Build Sutton North - Cumberland 500 kV line			
Sutton North 500 *kV*	2272	$ 917	$ 0.40

II. 2020 Offshore Wind Study Scope and Methodology

This offshore wind study was requested by the Southeastern Wind Coalition (SEWC) as a Local Public Policy study request. NCTPC had previously performed an offshore wind study in 2012. The 2012 study focused on the transmission infrastructure needed to accommodate preset levels of MW injection to the grid from offshore wind generation. SEWC asked for an update to that study with a focus on finding natural breakpoints where transmission upgrades would be needed, instead of preset MW test levels. Offshore wind injections up to 5000 MW were requested.

II.A. Generator Interconnections and Base Case

Any study by NCTPC for potential new generation connected to the Duke Energy transmission system is subject to limitations in accuracy and applicability. The official processes to connect generation to the Duke Energy systems in North and South Carolina are the FERC Large Generator Interconnection Procedures (LGIP) and Small Generator Interconnection Procedures (SGIP) and the North and South Carolina state interconnection procedures. Those procedures prioritize generator interconnections on a first come, first served basis, and those interconnection queues are currently backlogged with dozens of requests. Similarly, the PJM generator interconnection process, which covers Dominion territory in northeastern NC and Virginia, also has a large, backlogged queue. Any offshore wind developer wanting to connect their project to the Duke Energy grid would need to enter the appropriate interconnection queue behind those generators already in the queue.

NCTPC studies do not attempt to replicate the official generation interconnection procedures. The official generator interconnection queues have many requests that may or may not move forward to interconnection and operation. Historically, 50% or fewer requests complete the process to operation. It is not possible to accurately predict which generators in the queues will go forward to completion.

As per the normal NCTPC modeling process, the 2030 Summer peak model only included generators that are operational or have fully executed interconnection agreements. This offshore wind study started with that 2030 summer model and made one prospective generator addition – the 2640 MW offshore wind interconnection request at Dominion's Fentress 500kV substation. This addition was made due to the project's relevance to the study at hand and its public announcement by Dominion. Other generation in the Dominion Virginia Balancing Authority Area was scaled down to compensate.

DEP TRM[4] cases were also created from the above offshore wind base case. However, those cases ended up being less limiting than the main offshore wind base case for the most part. DEP TRM cases result in reduced DEP generation and DEP additional imports, whereas the purpose of the offshore wind study is to add offshore wind generation to the DEP area and export 60% of it to DEC, thus netting lower flows in the TRM cases versus the base case.

II.B. Injection Capability Calculation via Transfer Capability Analysis

The method to test injection of offshore wind power at various stations in eastern DEP in this study was using linear transfer capability analysis with the TARA software from PowerGEM. One at a time, power was ramped up at each of the 32 injection sites, keeping track of transmission limits found. As power was increased at each injection site, an equivalent amount of generation was decreased in DEC (60%) and DEP (40%) using participation

[4] Transmission Reliability Margin – more fully described in the NCTPC 2020 Annual Planning Report

factors provided by each company. This method is called First Contingency Incremental Transfer Capability (FCITC).

For each transmission limit found, a rough upgrade was determined based on the transmission owner's knowledge of the limiting element. For example, transmission lines that were limited by low line conductor clearances were assumed to be upgraded by raising the clearance of the line. Lines that were limited by the line conductor already at maximum clearance were assumed to be reconductored to a larger conductor. Limiting transmission transformers were upgraded to a larger size. Assumed standard upgrade costs are provided in Appendix B.

For each injection site, limiting lines and transformers were upgraded and the total cumulative upgrade cost at each site was recorded. Analysis and upgrades at a given site continued until cost per MW rose too high, using engineering judgement.

Full detailed MW injection capabilities and costs are provided in Appendix A. The results are for non-simultaneous injection at one site at a time. Injection of offshore wind generation at multiple sites was not studied. The results shown are indicative only and official interconnection and network upgrade costs would be determined in the official interconnection process.

For the two sites in Dominion, Fentress 500kV and Landstown 230kV, the injected power was sent to DEC (60%) and DEP (40%), same as with the DEP sites. Potential overloads and upgrade costs in Dominion/PJM were not included in the analysis, nor were PJM wheeling fees to transport the power across the Dominion/PJM system to Duke Energy.

This study included only power flow analysis, and only DEC and DEP transmission flows were monitored. Stability and short circuit analysis were not included and would be a significant requirement for an official system impact study for offshore wind generation, possibly incurring additional transmission upgrade costs.

II.C. Three Sites Analyzed at Higher Injection Levels

1. Three Sites Selected

Based on the results of screening the 32 sites for MW injection levels and costs, three sites were selected for further analysis and injection of higher MW levels. The first site that stood out for high MW capability at relatively lower cost was DEP's New Bern 230kV Substation. The initial screening results showed injection capability at New Bern 230kV of well over 1000 MW for well under $0.20 per Watt. New Bern benefits from already having five 230kV lines, two of which head in the direction of the DEP Raleigh load center. In addition, DEP has a partial right-of-way (ROW) available from New Bern 230kV to Wommack 230kV and a full 500kV ROW from Wommack 230kV to Wake 500kV.

None of the other sites stood out for both high MW and low cost, but the other two sites were selected for geographic diversity. Greenville 230kV was selected for its high initial MW screening levels, although the cost is also high per Watt injected. Another caveat with Greenville 230kV is that it borders the PJM/Dominion area, and there may be additional significant upgrades required in the PJM/Dominion area that were not determined in this study.

For diversity, a site in the more south-eastern part of DEP was desired. Sites very close to the coast, such as Brunswick or Castle Hayne, are not ideal due to known constraints in getting more power out of those areas. However, DEP has been aware of a possible new 230kV switching station site north of the Sutton Plant where three 230kV transmission lines share a ROW. This potential future Sutton North 230kV Switching Station was chosen as the third site. This site was added to the initial screening analysis as a 32nd site for screening to put it on the same basis as the original 31 sites.

2. 500kV Transmission Infrastructure

Because the study scope was looking for injection levels in the 1000s of MW, and since the three selected sites had already been screened with basic upgrades of existing 230kV and 115kV lines, this additional analysis of the three selected sites started with building a 500kV transmission path from each site to the existing DEP 500kV transmission system.

As mentioned, New Bern 230kV already has potential ROW to Wommack and on to Wake 500kV, so two new 500kV lines were specified for New Bern: New Bern – Wommack 500kV and Wommack – Wake 500kV. See Figure 1. New Bern and Wommack started with a single 500/230kV transformer rated 1000/1120 MVA like other existing DEP transformers. It was quickly determined that New Bern would need two such transformers, and they could be upsized to 1500/1680 MVA like some transformers utilized by DEC to achieve even higher levels of MW injection.

Due to the existing 500kV ROW from Wommack to Wake, the Greenville site 500kV path was built as a Greenville-Wommack 500kV line and then the same Wommack-Wake 500kV line as the New Bern option. See Figure 2.

The Sutton North site was studied with two different 500kV options because neither route stood out as obviously superior. One path was a 500kV line from Sutton North to Wommack, and then build the Wommack-Wake 500kV line. See Figure 3. While this does take advantage of the existing Wommack-Wake 500kV ROW, it is a long distance from Sutton North to Wommack. The other option analyzed for Sutton North was a 500kV line built directly from Sutton North to the existing Cumberland 500kV Substation. See Figure 4. This is a shorter total 500kV line length, but all new ROW would have to be acquired, and prior generation studies have shown low injection limits at Cumberland.

For each of the three sites, once a 500kV bus was added, generation could be interconnected at either 230kV or 500kV buses. Each of these was separately analyzed.

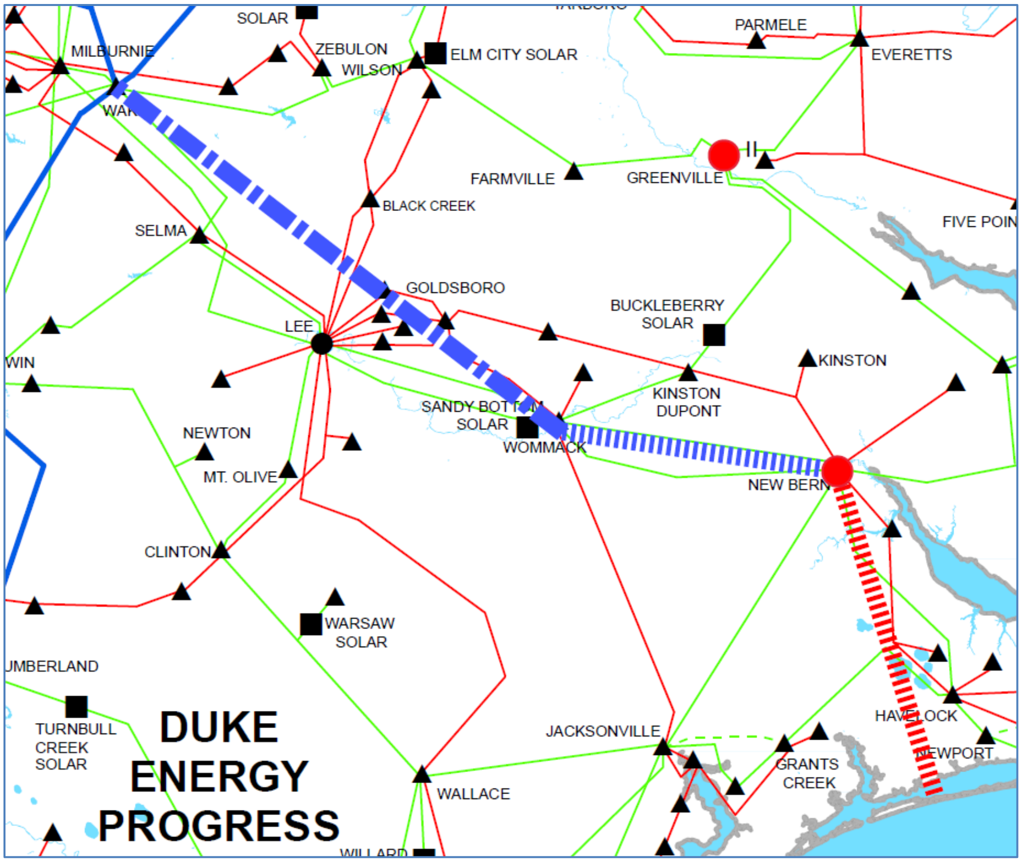

Figure 1. New Bern – Wommack – Wake 500kV Path

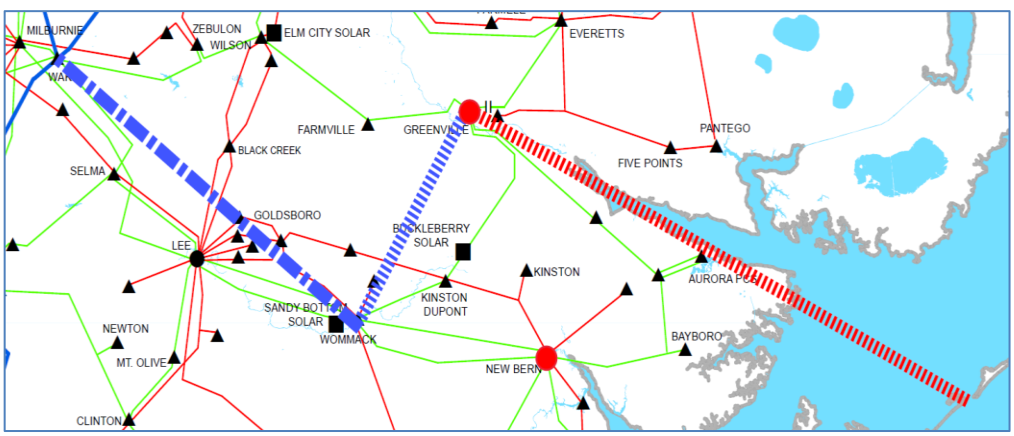

Figure 2. Greenville – Wommack – Wake 500kV Path

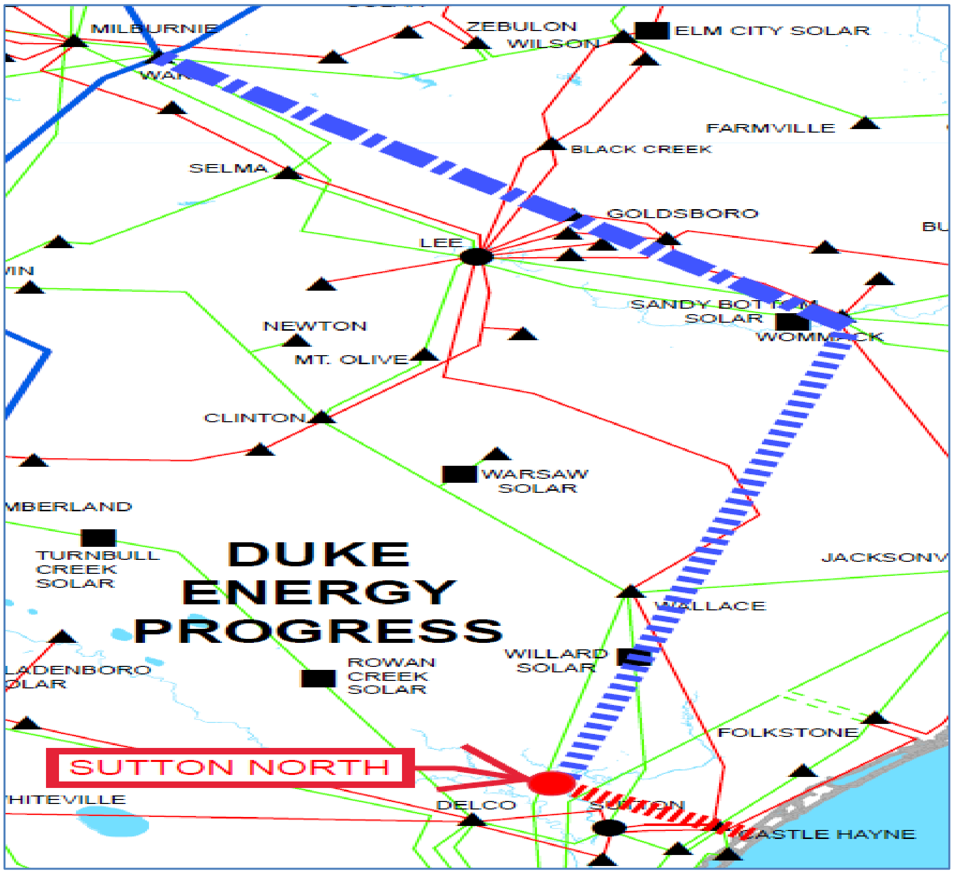

Figure 3. Sutton North – Wommack – Wake 500kV Path

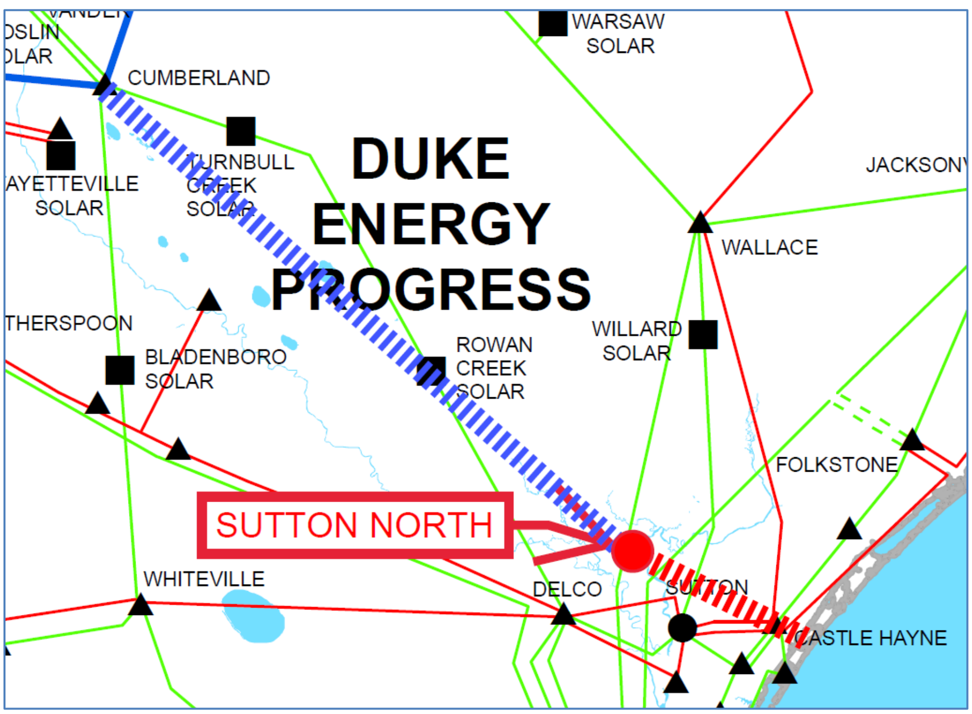

Figure 4. Sutton North – Cumberland 500kV Path

3. Results for Three Selected Sites at Higher Injection Levels

Appendix A.2 gives the full analysis results for the three selected sites with 500kV line build-out, and a summary was provided in the Executive Summary. New Bern and Greenville injection levels were able to reach well over 3000 MW each, but the costs per Watt were much higher than with the initial screening at lower MW levels. Costs were also high at Sutton North but limited to lower MW levels before costs began escalating even higher.

At New Bern, costs of achieving over 3000 MW of offshore wind generation injection are in the $0.40 per Watt range. Greenville was more expensive at $0.60 per Watt and higher for over 3000 MW of offshore wind injection. As mentioned before, the Greenville site may also have some significant unknown costs in PJM/Dominion. Sutton North was able to achieve costs of a little over $0.40 per Watt with the 500kV line to Cumberland, but only up to around 2500 MW. The Sutton North route to Wommack and Wake was also limited to a similar MW level, but this route cost more at around $0.60 per Watt.

As a reminder, this study does not include generation from the DEC, DEP, or PJM generator interconnection queues, and the results of this study could change significantly depending on what generation moves to construction and operation before any proposed offshore wind generation. Results are non-simultaneous and do not include consideration of stability and short-circuit levels.

Appendix A
Detailed Results

Yellow Highlight: Selected lower-cost injection levels at each site
Green Highlight: Three sites selected for investigation of higher injection levels
Gray Highlight: Existing transmission projects

An incremental cost per Watt of "#DIV/0!" in the tables below is not an error. In a few cases an upgrade did not increase injection capability at all (0 MW increase) because the following limit was at the same MW injection level.

Appendix A.1 – Results for 32 Injection Sites without 500kV Additions

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6AURORASST							Interconnection	46	Interconnection from the Beach	n/a	n/a	$ 230
6AURORASST	544	544	$ 230	$ 0.42	$ 230	$ 0.42	304454 AURORA SS TT 230 304449 EDWARDS TAP 230 1	0.96	Raise to 212F	594	594	$ 2
6AURORASST	548	4	$ 2	$ 0.48	$ 232	$ 0.42	304454 AURORA SS TT 230 304434 BAYBORO TAP 230 1	10.74	Raise to 212F	594	594	$ 21
6AURORASST	558	10	$ 21	$ 2.15	$ 253	$ 0.45	304449 EDWARDS TAP 230 304473 PA-WASHINTON 230 1	19.03	Raise to 212F	594	594	$ 38
6AURORASST	576	18	$ 38	$ 2.11	$ 291	$ 0.51	304445 CHOCOWINITY 230 304451 GREENVILE TT 230 1	18.57	Raise to 212F	482	482	$ 37
6AURORASST	577	1	$ 37	$ 37.14	$ 329	$ 0.57	304434 BAYBORO TAP 230 305142 E16-FAIRFELD 230 1	8.53	Raise to 212F	594	594	$ 17
6AURORASST	589	12	$ 17	$ 1.42	$ 346	$ 0.59	305142 E16-FAIRFELD 230 304463 NEW BERN WES 230 1	7.46	Raise to 212F	594	594	$ 15
6AURORASST	601	12	$ 15	$ 1.24	$ 361	$ 0.60	304463 NEW BERN WES 230 304465 NEWBERN230TT 230 1	1.02	Raise to 212F	594	594	$ 2
6AURORASST	605	4	$ 2	$ 0.51	$ 363	$ 0.60	304473 PA-WASHINTON 230 304445 CHOCOWINITY 230 1	0.04	Raise to 212F	594	594	$ 0
6AURORASST	619	14	$ 0	$ 0.01	$ 363	$ 0.59	304445 CHOCOWINITY 230 304451 GREENVILE TT 230 1	18.57	Reconductor to 6-1590 ACSR	1195	1195	$ 74
6BRUN1230T							Interconnection	5	Interconnection from the Beach	n/a	n/a	$ 25
6BRUN1230T	255	255	$ 25	$ 0.10	$ 25	$ 0.10	304022 BRUN1 230 TT 230 304610 SPRT &PA TAP 230 1	0.09	Reconductor to 6-1590 ACSR	1195	1195	$ 0
6BRUN1230T	368	113	$ 0	$ 0.00	$ 25	$ 0.07	304022 BRUN1 230 TT 230 305009 E1-DAWSCREEK 230 1	12.9	Station/relay upgrades	846	846	$ 1
6BRUN1230T	387	19	$ 1	$ 0.05	$ 26	$ 0.07	304610 SPRT &PA TAP 230 305010 E1-BOLIVIA 230 1	13.16	9th line	-	-	$ 100
6BRUN2230T							Interconnection	5	Interconnection from the Beach	n/a	n/a	$ 25
6BRUN2230T	159	159	$ 25	$ 0.16	$ 25	$ 0.16	304020 BRUN2 230 TT 230 305005 E1-SOUTHPORT 230 1	2.34	Raise to 212F	594	594	$ 5
6BRUN2230T	277	118	$ 5	$ 0.04	$ 30	$ 0.11	304020 BRUN2 230 TT 230 304621 TOWN CRK TT 230 1	14.67	Raise to 212F	846	846	$ 29
6BRUN2230T	308	31	$ 29	$ 0.95	$ 59	$ 0.19	304621 TOWN CRK TT 230 304615 BARNCRK E TT 230 2	1.42	9th line - Brunswick - Sutton North	-	-	$ 100
6CASTLEH230T							Interconnection	9	Interconnection from the Beach	n/a	n/a	$ 45
6CASTLEH230T							304551 CASTLH115ETT 115 304532 VISTA 115 1	15.96	Existing Project	297	297	$ -
6CASTLEH230T							304532 VISTA 115 305063 E9-HUGHBATTS 115 1	1.88	Existing Project	297	297	$ -
6CASTLEH230T	534	534	$ -	$ -	$ -	$ -	304550 CASTLEH230TT 230 304564 SCOTT TAP 230 1	6.18	Double Breaker Wallace 230	-	-	$ 5
6CASTLEH230T	547	13	$ 5	$ 0.38	$ 5	$ 0.01	304550 CASTLEH230TT 230 304545 CASTLH115WTT 115 1	-	Replace with 336 MVA	336	427	$ 4
6CASTLEH230T	752	205	$ 4	$ 0.02	$ 9	$ 0.01	304550 CASTLEH230TT 230 304564 SCOTT TAP 230 1	6.18	Reconductor to 6-1590 ACSR	1195	1195	$ 25
6CASTLEH230T	994	242	$ 25	$ 0.10	$ 34	$ 0.03	304545 CASTLH115WTT 115 304533 INDUSTR TAP 115 1	2.55	Reconductor to 3-1590 ACSR	311	311	$ 10
6CASTLEH230T	1048	54	$ 10	$ 0.19	$ 44	$ 0.04	304533 INDUSTR TAP 115 304513 BURGAW SUB 115 1	14.31	Raise to 212F	131	131	$ 29
6CLINTON230T							Interconnection	60	Interconnection from the Beach	n/a	n/a	$ 300
6CLINTON230T	758	758	$ 300	$ 0.40	$ 300	$ 0.40	304205 CLINTON230TT 230 304255 CLINTON115TT 115 1	-	Add 2nd bank (336 MVA)	336	427	$ 7
6CLINTON230T	717	-41	$ 7	$ (0.17)	$ 307	$ 0.43	304255 CLINTON115TT 115 305131 E15-HARGROVE 115 1	3.97	Raise to 212F	164	164	$ 8
6CLINTON230T	768	51	$ 8	$ 0.16	$ 315	$ 0.41	305131 E15-HARGROVE 115 304266 FAISNHWYIND 115 1	2.92	Raise to 212F	164	164	$ 6
6CLINTON230T	815	47	$ 6	$ 0.12	$ 321	$ 0.39	304278 MT OLV115 TT 115 304237 MT OLIVE TAP 115 1	0.09	Reconductor to 3-1590 ACSR	311	311	$ 0

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6CLINTON230T	853	38	$ 0	$ 0.01	$ 321	$ 0.38	304266 FAISNHWYIND 115 304278 MT OLV115 TT 115 1	6.38	Raise to 212F	164	164	$ 13
6CLINTON230T	936	83	$ 13	$ 0.15	$ 334	$ 0.36	304237 MT OLIVE TAP 115 304270 MT OLV WEST 115 1	1.35	Raise to 212F	164	164	$ 3
6CLINTON230T	946	10	$ 3	$ 0.27	$ 337	$ 0.36	304255 CLINTON115TT 115 305131 E15-HARGROVE 115 1	3.97	Reconductor to 3-1590 ACSR	311	311	$ 16
6CUMBLND230T							Interconnection	72	Interconnection from the Beach	n/a	n/a	$ 360
6CUMBLND230T	1018	1018	$ 360	$ 0.35	$ 360	$ 0.35	304390 CUMBLND230TT 230 304387 FAY 230 TT 230 2	13.73	Add 2nd 500/230kV bank	1120	1120	$ 15
6CUMBLND230T	1461	443	$ 15	$ 0.03	$ 375	$ 0.26	304389 FAYEAST230TT 230 304305 LINDEN SUB 230 1	12.2	Reconductor to 6-1590 ACSR	1195	1195	$ 49
6CUMBLND230T	1461	0	$ 49	#DIV/0!	$ 424	$ 0.29	304305 LINDEN SUB 230 304196 ERWIN230 TT 230 1	10.95	Reconductor to 6-1590 ACSR	1195	1195	$ 44
6CUMBLND230T	1729	268	$ 44	$ 0.16	$ 468	$ 0.27	304390 CUMBLND230TT 230 304387 FAY 230 TT 230 2	13.74	Reconductor to 6-1590 ACSR	1195	1195	$ 55
6DELCO230T							Interconnection	30	Interconnection from the Beach	n/a	n/a	$ 150
6DELCO230T	486	486	$ 150	$ 0.31	$ 150	$ 0.31	304582 DELCO230 TT 230 304587 DELCO115W TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6DELCO230T	728	242	$ 4	$ 0.02	$ 154	$ 0.21	304039 SUTTON230 TT 230 304554 WILM N&O TAP 230 1	5.38	Reconductor to 6-1590 ACSR	1195	1195	$ 22
6DELCO230T	843	115	$ 22	$ 0.19	$ 176	$ 0.21	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Raise to 212F	594	594	$ 7
6DELCO230T	1036	193	$ 7	$ 0.04	$ 183	$ 0.18	304039 SUTTON230 TT 230 304520 WILM INVISTA 230 1	1.79	Raise to 212F	594	594	$ 4
6DELCO230T	1049	13	$ 4	$ 0.28	$ 186	$ 0.18	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Raise to 212F	594	594	$ 9
6DELCO230T	1125	76	$ 9	$ 0.12	$ 195	$ 0.17	304520 WILM INVISTA 230 304534 WILM PRAX 230 1	0.39	Raise to 212F	594	594	$ 1
6DELCO230T	1150	25	$ 1	$ 0.03	$ 196	$ 0.17	304516 WILM BASF 230 305470 WILARDSOLTAP 230 1	20.22	Raise to 212F	594	594	$ 40
6DELCO230T	1223	73	$ 40	$ 0.55	$ 236	$ 0.19	304554 WILM N&O TAP 230 304552 WILM EAST 230 1	2.72	Reconductor to 6-1590 ACSR	1195	1195	$ 11
6FLOSUB230T							Interconnection	64	Interconnection from the Beach	n/a	n/a	$ 320
6FLOSUB230T	553	553	$ 320	$ 0.58	$ 320	$ 0.58	306416 WATEREE 100 306375 GT FALL1 100 1	20	Reconductor to 954 ACSR	232	260	$ 80
6FLOSUB230T	911	358	$ 80	$ 0.22	$ 400	$ 0.44	304662 FLO SUB230TT 230 304663 LATTA SS TT 230 1	23.59	Reconductor to 6-1590 ACSR	1195	1195	$ 94
6FLOSUB230T	1199	288	$ 94	$ 0.33	$ 494	$ 0.41	304662 FLO SUB230TT 230 304707 FLOSUB115ETT 115 2	-	Replace with 448 MVA	448	560	$ 4
6FOLKSTN230T							Interconnection	10	Interconnection from the Beach	n/a	n/a	$ 50
6FOLKSTN230T							304543 FOLKSTN115TT 115 305061 E9-DAWSON 115 1	8.77	Existing Project	221	221	$ -
6FOLKSTN230T	328	328	$ -	$ -	$ -	$ -	304542 FOLKSTN230TT 230 304543 FOLKSTN115TT 115 1	-	Add 2nd bank (336 MVA)	336	427	$ 7
6FOLKSTN230T	518	190	$ 7	$ 0.04	$ 7	$ 0.01	304543 FOLKSTN115TT 115 305061 E9-DAWSON 115 1	8.77	Reconductor to 3-1590 ACSR	340	340	$ 35
6FOLKSTN230T	577	59	$ 35	$ 0.59	$ 42	$ 0.07	305061 E9-DAWSON 115 305073 E9-SOUTHWEST 115 1	18.5	Reconductor to 3-1590 ACSR	340	340	$ 74
6GREENVIL230							Interconnection	85	Interconnection from the Beach	n/a	n/a	$ 425
6GREENVIL230	1106	1106	$ 425	$ 0.38	$ 425	$ 0.38	304451 GREENVILE TT 230 314574 6EVERETS 230 1	22.21	Reconductor to 6-1590 ACSR	1195	1195	$ 89
6GREENVIL230	1184	78	$ 89	$ 1.14	$ 514	$ 0.43	304451 GREENVILE TT 230 304452 GREENVILE W 230 1	4.1	Reconductor to 6-1590 ACSR	1195	1195	$ 16
6GREENVIL230	1224	40	$ 16	$ 0.41	$ 530	$ 0.43	304452 GREENVILE W 230 304229 PA-FARMVILLE 230 1	9.61	Reconductor to 6-1590 ACSR	1195	1195	$ 38
6GREENVIL230	1283	59	$ 38	$ 0.65	$ 569	$ 0.44	304229 PA-FARMVILLE 230 304228 WILSON230 TT 230 1	20.28	Reconductor to 6-1590 ACSR	1195	1195	$ 81
6GREENVIL230	1465	182	$ 81	$ 0.45	$ 650	$ 0.44	304451 GREENVILE TT 230 304445 CHOCOWINITY 230 1	18.61	Reconductor to 6-1590 ACSR	1195	1195	$ 74
6GREENVIL230	1601	136	$ 74	$ 0.55	$ 724	$ 0.45	304473 PA-WASHINTON 230 304449 EDWARDS TAP 230 1	19.03	Raise to 212F	594	594	$ 38
6GREENVIL230	1628	27	$ 38	$ 1.41	$ 762	$ 0.47	304449 EDWARDS TAP 230 304454 AURORA SS TT 230 1	0.96	Raise to 212F	594	594	$ 2
6GREENVIL230	1784	156	$ 2	$ 0.01	$ 764	$ 0.43	304445 CHOCOWINITY 230 304473 PA-WASHINTON 230 1	0.04	Reconductor to 6-1590 ACSR	1195	1195	$ 0
6GREENVIL230	1825	41	$ 0	$ 0.00	$ 764	$ 0.42	304454 AURORA SS TT 230 304434 BAYBORO TAP 230 1	10.74	Raise to 212F	594	594	$ 21
6GREENVIL230	1902	77	$ 21	$ 0.28	$ 786	$ 0.41	304434 BAYBORO TAP 230 305142 E16-FAIRFELD 230 1	8.53	Raise to 212F	594	594	$ 17

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6GREENVIL230	1933	31	$ 17	$ 0.55	$ 803	$ 0.42	305142 E16-FAIRFELD 230 304463 NEW BERN WES 230 1	7.46	Raise to 212F	594	594	$ 15
6GREENVIL230	1948	15	$ 15	$ 0.99	$ 818	$ 0.42	304449 EDWARDS TAP 230 304454 AURORA SS TT 230 1	0.96	Reconductor to 6-1590 ACSR	1195	1195	$ 4
6GRNTSCK230T							Interconnection	14	Interconnection from the Beach	n/a	n/a	$ 70
6GRNTSCK230T	746	746	$ 70	$ 0.09	$ 70	$ 0.09	304518 GRNTSCK230TT 230 304527 SWANSBORO 230 1	4.73	Double Breaker New Bern 230	-	-	$ 4
6GRNTSCK230T	758	12	$ 4	$ 0.33	$ 74	$ 0.10	304518 GRNTSCK230TT 230 305078 E9-PINEY GR2 230 1	1	Double Breaker Grants Cr 230	-	-	$ 5
6GRNTSCK230T	966	208	$ 5	$ 0.02	$ 79	$ 0.08	304527 SWANSBORO 230 305018 E2-MAYSVILLE 230 1	3.73	Reconductor to 6-1590 ACSR	1195	1195	$ 15
6GRNTSCK230T	1055	89	$ 15	$ 0.17	$ 94	$ 0.09	305077 E9-RAMSEY RD 230 305076 E9-HORACE 230 1	13.14	Reconductor to 6-1590 ACSR	1195	1195	$ 53
6HAVELOK230T							Interconnection	4	Interconnection from the Beach	n/a	n/a	$ 20
6HAVELOK230T	859	859	$ 20	$ 0.02	$ 20	$ 0.02	304484 HAVELOK230TT 230 304465 NEWBERN230TT 230 1	23.47	Raise to 212F	594	594	$ 47
6HAVELOK230T	1001	142	$ 47	$ 0.33	$ 67	$ 0.07	304484 HAVELOK230TT 230 304465 NEWBERN230TT 230 1	23.47	Reconductor to 6-1590 ACSR	1195	1195	$ 94
6JACKSON230T							Interconnection	20	Interconnection from the Beach	n/a	n/a	$ 100
6JACKSON230T	897	897	$ 100	$ 0.11	$ 100	$ 0.11	304518 GRNTSCK230TT 230 304527 SWANSBORO 230 1	4.73	Double Breaker New Bern 230	-	-	$ 4
6JACKSON230T	929	32	$ 4	$ 0.13	$ 104	$ 0.11	304471 CC WD EN TAP 230 304465 NEWBERN230TT 230 1	2.12	Reconductor to 6-1590 ACSR	1195	1195	$ 8
6JACKSON230T	979	50	$ 8	$ 0.17	$ 112	$ 0.11	304524 JACKSON230TT 230 305077 E9-RAMSEY RD 230 1	1.26	Reconductor to 6-1590 ACSR	1195	1195	$ 5
6JACKSON230T	1049	70	$ 5	$ 0.07	$ 118	$ 0.11	305077 E9-RAMSEY RD 230 305076 E9-HORACE 230 1	13.14	Reconductor to 6-1590 ACSR	1195	1195	$ 53
6JACKSON230T	1050	1	$ 53	$ 52.56	$ 170	$ 0.16	304525 JACKSN115ETT 115 305065 E9-GUMBRNCH 115 1	4.69	Raise to 212F	221	221	$ 9
6JACKSON230T	1068	18	$ 9	$ 0.52	$ 179	$ 0.17	305076 E9-HORACE 230 304528 RHEMS 230 1	7.64	Reconductor to 6-1590 ACSR	1195	1195	$ 31
6KINDUP230TT							Interconnection	30	Interconnection from the Beach	n/a	n/a	$ 150
6KINDUP230TT	722	722	$ 150	$ 0.21	$ 150	$ 0.21	304475 WEYER TAP 115 304466 NEWBER115NTT 115 1	6.08	Double Breaker New Bern 230	-	-	$ 4
6KINDUP230TT	851	129	$ 4	$ 0.03	$ 154	$ 0.18	304475 WEYER TAP 115 304466 NEWBER115NTT 115 1	6.08	Raise to 212F	202	202	$ 12
6KINDUP230TT	858	7	$ 12	$ 1.74	$ 166	$ 0.19	304480 KINSDUP115TT 115 304477 VOA TAP 115 1	10.94	Raise to 212F	202	202	$ 22
6KINDUP230TT	878	20	$ 22	$ 1.09	$ 188	$ 0.21	304477 VOA TAP 115 304475 WEYER TAP 115 1	12.53	Raise to 212F	202	202	$ 25
6KINDUP230TT	1055	177	$ 25	$ 0.14	$ 213	$ 0.20	304474 KINSDUP230TT 230 304480 KINSDUP115TT 115 1	-	Uprate	336	427	$ 1
6KINDUP230TT	1103	48	$ 1	$ 0.02	$ 214	$ 0.19	304480 KINSDUP115TT 115 304481 PA-AYDEN 115 1	1.27	Raise to 212F	202	202	$ 3
6KINDUP230TT	1202	99	$ 3	$ 0.03	$ 217	$ 0.18	304481 PA-AYDEN 115 304459 GRIFTON 115 1	0.01	Raise to 212F	202	202	$ 0
6KINGSTR230T							Interconnection	45	Interconnection from the Beach	n/a	n/a	$ 225
6KINGSTR230T	667	667	$ 225	$ 0.34	$ 225	$ 0.34	304675 LAKE CITY 230 304674 OLANTA 230 1	8.08	Raise to 212F	542	542	$ 16
6KINGSTR230T	681	14	$ 16	$ 1.15	$ 241	$ 0.35	304674 OLANTA 230 304671 FLOR SARDIS 230 1	7.45	Raise to 212F	542	542	$ 15
6KINGSTR230T	687	6	$ 15	$ 2.48	$ 256	$ 0.37	304677 KINGSTR230TT 230 304676 KINGSTREE N 230 1	5.71	Raise to 212F	594	594	$ 11
6KINGSTR230T	704	17	$ 11	$ 0.67	$ 267	$ 0.38	304671 FLOR SARDIS 230 304673 FLOR EBENEZR 230 1	9.38	Raise to 212F	542	542	$ 19
6KINGSTR230T	705	1	$ 19	$ 18.76	$ 286	$ 0.41	304675 LAKE CITY 230 304674 OLANTA 230 1	8.08	Reconductor to 6-1590 ACSR	1195	1195	$ 32
6KINGSTR230T	709	4	$ 32	$ 8.08	$ 319	$ 0.45	304676 KINGSTREE N 230 304675 LAKE CITY 230 1	11.08	Raise to 212F	594	594	$ 22
6KINGSTR230T	711	2	$ 22	$ 11.08	$ 341	$ 0.48	304678 KINGSTR115TT 115 304679 KINGTREE SUB 115 1	0.15	Reconductor to 3-1590 ACSR	340	340	$ 1
6LANDSTN							Interconnection	8	Interconnection from the Beach	n/a	n/a	$ 40
6LANDSTN	1342	1342	$ 40	$ 0.03	$ 40	$ 0.03	314554 3BTLEBRO 115 304223 ROCKYMT115TT 115 1	8.5	Reconductor to 3-795 ACSS	314	314	$ 25
6LANDSTN	2257	915	$ 25	$ 0.03	$ 65	$ 0.03	314574 6EVERETS 230 304451 GREENVILE TT 230 1	22.21	Reconductor to 6-1590 ACSR	1195	1195	$ 89

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6LANDSTN	3109	852	$ 89	$ 0.10	$ 154	$ 0.05	306540 6MCGUIRE 230 306443 6MARSHAL 230 1&2	-	Rebuild in plan	-	-	$ -
6LATTASST							Interconnection	53	Interconnection from the Beach	n/a	n/a	$ 265
6LATTASST	425	425	$ 265	$ 0.62	$ 265	$ 0.62	304632 MARION115 TT 115 304653 DILLON TAP 115 1	14.6	Reconductor to 3-1590 ACSR	311	311	$ 58
6LATTASST	618	193	$ 58	$ 0.30	$ 323	$ 0.52	304663 LATTA SS TT 230 304682 DILLONMP TAP 230 1	4.43	Raise to 212F	542	542	$ 9
6LATTASST	663	45	$ 9	$ 0.20	$ 332	$ 0.50	304682 DILLONMP TAP 230 304046 WSPOON230 TT 230 1	27.96	Raise to 212F	542	542	$ 56
6LEESUB230T							Interconnection	70	Interconnection from the Beach	n/a	n/a	$ 350
6LEESUB230T	1103	1103	$ 350	$ 0.32	$ 350	$ 0.32	304251 LEESUB230 TT 230 304261 LEESUB115STT 115 2	-	Replace with 448 MVA	448	560	$ 5
6LEESUB230T	1103	0	$ 5	#DIV/0!	$ 355	$ 0.32	304251 LEESUB230 TT 230 304261 LEESUB115STT 115 1	-	Replace with 448 MVA	448	560	$ 5
6LEESUB230T	1151	48	$ 5	$ 0.10	$ 360	$ 0.31	304251 LEESUB230 TT 230 304179 WILSON MILLS 230 1	20.36	Reconductor to 6-1590 ACSR	1195	1195	$ 81
6LEESUB230T	1245	94	$ 81	$ 0.87	$ 441	$ 0.35	304251 LEESUB230 TT 230 304192 SELMA 230 TT 230 1	0.04	Reconductor to 6-1590 ACSR + ancillary	1195	1195	$ 2
6MARION230T							Interconnection	46	Interconnection from the Beach	n/a	n/a	$ 230
6MARION230T	391	391	$ 230	$ 0.59	$ 230	$ 0.59	304632 MARION115 TT 115 304653 DILLON TAP 115 1	14.6	Reconductor to 3-1590 ACSR	311	311	$ 58
6MARION230T	876	485	$ 58	$ 0.12	$ 288	$ 0.33	304631 MARION230 TT 230 304632 MARION115 TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6MARION230T	907	31	$ 4	$ 0.13	$ 292	$ 0.32	304631 MARION230 TT 230 304632 MARION115 TT 115 2	-	Replace with 336 MVA	336	427	$ 4
6MARION230T	930	23	$ 4	$ 0.17	$ 296	$ 0.32	304653 DILLON TAP 115 304447 FAIRMONT TAP 115 1	13.7	Reconductor to 3-1590 ACSR	311	311	$ 55
6MORHDWW230T							Interconnection	4	Interconnection from the Beach	n/a	n/a	$ 20
6MORHDWW230T	336	336	$ 20	$ 0.06	$ 20	$ 0.06	304497 MORHDWW230TT 230 304498 MORHDWW115TT 115 1	-	Add 2nd bank (336 MVA)	336	427	$ 7
6MORHDWW230T	527	191	$ 7	$ 0.04	$ 27	$ 0.05	304498 MORHDWW115TT 115 304496 MORWW 115/24 115 1	0.04	Reconductor to 3-1590 ACSR	340	340	$ 0
6MORHDWW230T	550	23	$ 0	$ 0.01	$ 27	$ 0.05	304496 MORWW 115/24 115 305019 E2-NEWPORT 115 1	3.22	Reconductor to 3-1590 ACSR	340	340	$ 13
6MTOLV230T							Interconnection	62	Interconnection from the Beach	n/a	n/a	$ 310
6MTOLV230T	224	224	$ 310	$ 1.38	$ 310	$ 1.38	304279 MT OLV230 TT 230 304278 MT OLV115 TT 115 1	-	Double Breaker Mt. Olive 230	-	-	$ 2
6MTOLV230T	637	413	$ 2	$ 0.00	$ 312	$ 0.49	304279 MT OLV230 TT 230 304278 MT OLV115 TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6NEWBERN230T							Interconnection	34	Interconnection from the Beach	n/a	n/a	$ 170
6NEWBERN230T	825	825	$ 170	$ 0.21	$ 170	$ 0.21	304465 NEWBERN230TT 230 304466 NEWBER115NTT 115 1	-	Replace with 336 MVA	336	427	$ 4
6NEWBERN230T	941	116	$ 4	$ 0.03	$ 174	$ 0.18	304465 NEWBERN230TT 230 304489 NEWBER115STT 115 2	-	Replace with 336 MVA	336	427	$ 4
6NEWBERN230T	1104	163	$ 4	$ 0.02	$ 178	$ 0.16	304489 NEWBER115STT 115 304466 NEWBER115NTT 115 Z1	-	Replace bus tie breaker	598	598	$ 1
6NEWBERN230T	1404	300	$ 1	$ 0.00	$ 179	$ 0.13	304465 NEWBERN230TT 230 304463 NEW BERN WES 230 1	1.02	Raise to 212F	594	594	$ 2
6NEWBERN230T	1449	45	$ 2	$ 0.05	$ 181	$ 0.12	304463 NEW BERN WES 230 305142 E16-FAIRFELD 230 1	7.46	Raise to 212F	594	594	$ 15
6NEWBERN230T	1496	47	$ 15	$ 0.32	$ 196	$ 0.13	304475 WEYER TAP 115 304477 VOA TAP 115 1	12.53	Raise to 212F	202	202	$ 25
6NEWBERN230T	1515	19	$ 25	$ 1.32	$ 221	$ 0.15	304477 VOA TAP 115 304480 KINSDUP115TT 115 1	10.94	Raise to 212F	202	202	$ 22
6NEWBERN230T	1773	258	$ 22	$ 0.08	$ 243	$ 0.14	304471 CC WD EN TAP 230 304528 RHEMS 230 1	5.62	Reconductor to 6-1590 ACSR	1195	1195	$ 22
6SUMTER230T							Interconnection	75	Interconnection from the Beach	n/a	n/a	$ 375
6SUMTER230T	558	558	$ 375	$ 0.67	$ 375	$ 0.67	306416 WATEREE 100 306375 GT FALL1 100 1	20	Reconductor to 954 ACSR	232	260	$ 80
6SUMTER230T	584	26	$ 80	$ 3.08	$ 455	$ 0.78	304700 SUMTER230 TT 230 304728 ELLIOTT TAP 230 1	20.41	Raise to 212F	542	542	$ 41
6SUMTER230T	608	24	$ 41	$ 1.70	$ 496	$ 0.82	304728 ELLIOTT TAP 230 304018 ROB2 230 TT 230 1	20.75	Raise to 212F	542	542	$ 42

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6SUMTER230T	748	140	$ 42	$ 0.30	$ 537	$ 0.72	304700 SUMTER230 TT 230 304728 ELLIOTT TAP 230 1	20.41	Reconductor to 6-1590 ACSR	1195	1195	$ 82
6SUTNORTH230							Interconnection	17	Interconnection from the Beach	n/a	n/a	$ 85
6SUTNORTH230	0	0	$ 85		$ 85		Build Sutton North 230kV SS	-	Build Switching Station	-	-	$ 25
6SUTNORTH230	695	695	$ 25	$ 0.04	$ 110	$ 0.16	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.55	Raise to 212F	594	594	$ 7
6SUTNORTH230	833	138	$ 7	$ 0.05	$ 117	$ 0.14	304039 SUTTON230 TT 230 304554 WILM N&O TAP 230 1	5.45	Reconductor to 6-1590 ACSR	1195	1195	$ 22
6SUTNORTH230	852	19	$ 22	$ 1.15	$ 139	$ 0.16	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Raise to 212F	594	594	$ 9
6SUTNORTH230	927	75	$ 9	$ 0.12	$ 148	$ 0.16	305995 6SUTNORTH230 230 305470 WILARDSOLTAP 230 1	19	Raise to 212F	594	594	$ 38
6SUTNORTH230	1024	97	$ 38	$ 0.39	$ 186	$ 0.18	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Raise to 212F	594	594	$ 55
6SUTNORTH230	1136	112	$ 55	$ 0.49	$ 241	$ 0.21	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Reconductor to 6-1590 ACSR	1195	1195	$ 110
6SUTNORTH230	1171	35	$ 110	$ 3.14	$ 351	$ 0.30	304582 DELCO230 TT 230 304587 DELCO115W TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6SUTNORTH230	1217	46	$ 4	$ 0.09	$ 355	$ 0.29	304554 WILM N&O TAP 230 304552 WILM EAST 230 1	2.72	Reconductor to 6-1590 ACSR	1195	1195	$ 11
6SUTNORTH230	1225	8	$ 11	$ 1.36	$ 366	$ 0.30	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.55	Reconductor to 6-1590 ACSR	1195	1195	$ 14
6WAKE230TT							Interconnection	90	Interconnection from the Beach	n/a	n/a	$ 450
6WAKE230TT	786	786	$ 450	$ 0.57	$ 450	$ 0.57	304156 ROL/SQD TAP 230 304276 KNIGHT HODG 230 1	4.83	Raise to 212F	1084	1084	$ 10
6WAKE230TT	849	63	$ 10	$ 0.15	$ 460	$ 0.54	304276 KNIGHT HODG 230 304162 MILBUR230 TT 230 1	2.19	Raise to 212F	1084	1084	$ 4
6WAKE230TT	1458	609	$ 4	$ 0.01	$ 464	$ 0.32	304190 WAKE 230 TT 230 304156 ROL/SQD TAP 230 1	0.17	New line	-	-	$ 100
6WALLACE230T							Interconnection	32	Interconnection from the Beach	n/a	n/a	$ 160
6WALLACE230T	548	548	$ 160	$ 0.29	$ 160	$ 0.29	304515 WALLACE230TT 230 305075 E9-W ONSLOW 230 1	19.7	Double Breaker Wallace 230	-	-	$ 5
6WALLACE230T	567	19	$ 5	$ 0.26	$ 165	$ 0.29	304515 WALLACE230TT 230 305075 E9-W ONSLOW 230 1	19.7	Raise to 212F	594	594	$ 39
6WALLACE230T	584	17	$ 39	$ 2.32	$ 204	$ 0.35	305075 E9-W ONSLOW 230 304521 CATHERN LAKE 230 1	7.69	Raise to 212F	594	594	$ 15
6WALLACE230T	618	34	$ 15	$ 0.45	$ 220	$ 0.36	304521 CATHERN LAKE 230 304524 JACKSON230TT 230 1	3.42	Raise to 212F	594	594	$ 7
6WALLACE230T	658	40	$ 7	$ 0.17	$ 227	$ 0.34	304515 WALLACE230TT 230 305075 E9-W ONSLOW 230 1	19.7	Reconductor to 6-1590 ACSR	1195	1195	$ 79
6WALLACE230T	675	17	$ 79	$ 4.64	$ 305	$ 0.45	305075 E9-W ONSLOW 230 304521 CATHERN LAKE 230 1	7.69	Reconductor to 6-1590 ACSR	1195	1195	$ 31
6WALLACE230T	691	16	$ 31	$ 1.92	$ 336	$ 0.49	304515 WALLACE230TT 230 304517 WALLACE115TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6WHITEVL230T							Interconnection	34	Interconnection from the Beach	n/a	n/a	$ 170
6WHITEVL230T	663	663	$ 170	$ 0.26	$ 170	$ 0.26	304020 BRUN2 230 TT 230 305005 E1-SOUTHPORT 230 1	2.34	Raise to 212F	594	594	$ 5
6WHITEVL230T	770	107	$ 5	$ 0.04	$ 175	$ 0.23	304580 WHITEVIL TAP 115 305003 E1-HALLSBORO 115 1	5.42	Reconductor to 3-1590 ACSR	340	340	$ 22
6WHITEVL230T	796	26	$ 22	$ 0.83	$ 196	$ 0.25	305003 E1-HALLSBORO 115 304575 LAKE WACCA 115 1	4.28	Reconductor to 3-1590 ACSR	340	340	$ 17
6WHITEVL230T	818	22	$ 17	$ 0.78	$ 213	$ 0.26	305330 BLADENSOLTAP 230 305034 E4-POWELL 230 1	1.73	Raise to 212F	594	594	$ 3
6WHITEVL230T	850	32	$ 3	$ 0.11	$ 217	$ 0.26	304600 WHITEVL230TT 230 305330 BLADENSOLTAP 230 1	15.91	Raise to 212F	594	594	$ 32
6WHITEVL230T	871	21	$ 32	$ 1.52	$ 249	$ 0.29	304575 LAKE WACCA 115 304587 DELCO115W TT 115 1	16.86	Reconductor to 3-1590 ACSR	340	340	$ 67
6WHITEVL230T	929	58	$ 67	$ 1.16	$ 316	$ 0.34	305034 E4-POWELL 230 305035 E4-TARHELL 230 1	12.91	Raise to 212F	542	542	$ 26
6WOMMACK230T							Interconnection	51	Interconnection from the Beach	n/a	n/a	$ 255
6WOMMACK230T	883	883	$ 255	$ 0.29	$ 255	$ 0.29	304500 WOMMACK230TT 230 304510 WOMACKW115TT 115 2	-	Replace with 336 MVA	336	427	$ 4
6WOMMACK230T	1432	549	$ 4	$ 0.01	$ 259	$ 0.18	304500 WOMMACK230TT 230 304507 WOMACKE115TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6WOMMACK230T	1432	0	$ 4	#DIV/0!	$ 263	$ 0.18	304030 LEESEP115WTT 115 305162 E17-ROSEWOOD 115 1	4.29	Reconductor to 3-1590 ACSR	311	311	$ 17
6WOMMACK230T	1471	39	$ 17	$ 0.44	$ 280	$ 0.19	304500 WOMMACK230TT 230 304506 DOVER 230 1	8.65	Raise to 212F	594	594	$ 17

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element					Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6WOMMACK230T	1519	48	$ 17	$ 0.36	$ 297	$ 0.20	304506 DOVER	230	304465 NEWBERN230TT	230	1	23.38	Raise to 212F	594	594	$ 47
6WSPOON230T							Interconnection					58	Interconnection from the Beach	n/a	n/a	$ 290
6WSPOON230T	311	311	$ 290	$ 0.93	$ 290	$ 0.93	304046 WSPOON230 TT	230	304047 WSPOON115 TT	115	1	-	Replace with 336 MVA and 1.5 breaker	336	427	$ 8
6WSPOON230T	498	187	$ 8	$ 0.04	$ 298	$ 0.60	304046 WSPOON230 TT	230	304047 WSPOON115 TT	115	2	-	Replace with 336 MVA and 1.5 breaker	336	427	$ 4
6WSPOON230T	788	290	$ 4	$ 0.01	$ 302	$ 0.38	305410 ROSLINSOLTAP	115	304403 HOPEMILLCHUR	115	1	3.07	Reconductor to 3-1590 ACSR	311	311	$ 13
8CUMBLND500T							Interconnection					72	Interconnection from the Beach	n/a	n/a	$ 360
8CUMBLND500T	1016	1016	$ 360	$ 0.35	$ 360	$ 0.35	304391 CUMBLND500TT	500	998843 CUMBERLAND1	230	1	-	Add 2nd 500/230kV bank	1120	1120	$ 15
8CUMBLND500T	1440	424	$ 15	$ 0.04	$ 375	$ 0.26	304391 CUMBLND500TT	500	998842 CUMBERLAND2	230	2	-	Get emergency ratings	1120	1400	$ 5
8CUMBLND500T	1700	260	$ 5	$ 0.02	$ 380	$ 0.22	304378 RICHMON230TT	230	304348 ROCKHAM230TT	230	1	-	New line	-	-	-
8FENTRES							Interconnection					15	Interconnection from the Beach	n/a	n/a	$ 75
8FENTRES	1383	1383	$ 75	$ 0.05	$ 75	$ 0.05	314554 3BTLEBRO	115	304223 ROCKYMT115TT	115	1	8.5	Reconductor to 3-795 ACSS	314	314	$ 25
8FENTRES	2307	924	$ 25	$ 0.03	$ 100	$ 0.04	314574 6EVERETS	230	304451 GREENVILE TT	230	1	22.21	Reconductor to 6-1590 ACSR	1195	1195	$ 89
8FENTRES	2813	506	$ 89	$ 0.18	$ 189	$ 0.07	306540 6MCGUIRE	230	306443 6MARSHAL	230	1&2	-	Planned upgrade	-	-	-
8WAKE500TT							Interconnection					90	Interconnection from the Beach	n/a	n/a	$ 450
8WAKE500TT	1310	1310	$ 450	$ 0.34	$ 450	$ 0.34	304156 ROL/SQD TAP	230	304276 KNIGHT HODG	230	1	4.83	Raise to 212F	1084	1084	$ 10
8WAKE500TT	1417	107	$ 10	$ 0.09	$ 460	$ 0.32	304276 KNIGHT HODG	230	304162 MILBUR230 TT	230	1	2.19	Raise to 212F	1084	1084	$ 4
8WAKE500TT	1451	34	$ 4	$ 0.13	$ 464	$ 0.32	304183 WAKE 500 TT	500	998846 WAKE2	230	2	-	Double Breaker Wake 500 ???	-	-	$ 20
8WAKE500TT	1454	3	$ 20	$ 6.67	$ 484	$ 0.33	304183 WAKE 500 TT	500	998847 WAKE1	230	1	-	Double Breaker Wake 500 ???	-	-	$ -

Appendix A.2 – Results for Three Selected Injection Sites with 500kV Transmission Additions

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6GREENVIL230	0						Interconnection	85	Interconnection from the Beach	-	-	$ 850
6GREENVIL230	1106	1106	$ 850	$ 0.77	$ 850	$ 0.77	304451 GREENVILE TT 230 314574 6EVERETS 230 1	22.21	Build Grnvl-Wom-Wake 500kV	-	-	$ 845
6GREENVIL230	1773	667	$ 845	$ 1.27	$ 1,695	$ 0.96	304451 GREENVILE TT 230 314574 6EVERETS 230 1	22.21	Add 2nd 500/230kV bank	1125	1125	$ 15
6GREENVIL230	1940	167	$ 15	$ 0.09	$ 1,710	$ 0.88	304451 GREENVILE TT 230 314574 6EVERETS 230 1	22.21	Reconductor to 6-1590 ACSR	1195	1195	$ 89
6GREENVIL230	2034	93	$ 89	$ 0.95	$ 1,799	$ 0.88	304451 GREENVILE TT 230 304452 GREENVILE W 230 1	4.1	Reconductor to 6-1590 ACSR	1195	1195	$ 16
6GREENVIL230	2135	102	$ 16	$ 0.16	$ 1,815	$ 0.85	304452 GREENVILE W 230 304229 PA-FARMVILLE 230 1	9.61	Reconductor to 6-1590 ACSR	1195	1195	$ 38
6GREENVIL230	2284	149	$ 38	$ 0.26	$ 1,854	$ 0.81	304229 PA-FARMVILLE 230 304228 WILSON230 TT 230 1	20.28	Reconductor to 6-1590 ACSR	1195	1195	$ 81
6GREENVIL230	2916	631	$ 81	$ 0.13	$ 1,935	$ 0.66	304451 GREENVILE TT 230 304445 CHOCOWINITY 230 1	18.61	Reconductor to 6-1590 ACSR	1195	1195	$ 74
6GREENVIL230	3074	158	$ 74	$ 0.47	$ 2,009	$ 0.65	306540 6MCGUIRE 230 306443 6MARSHAL 230 2	13.8	Reconductor already planned	-	-	$ 0
6GREENVIL230	3227	153	$ 0	$ 0.00	$ 2,009	$ 0.62	304445 CHOCOWINITY 230 304473 PA-WASHINTON 230 1	0.04	Reconductor to 6-1590 ACSR	1195	1195	$ 0.2
6GREENVIL230	3587	360	$ 0	$ 0.00	$ 2,010	$ 0.56	304480 KINSDUP115TT 115 304481 PA-AYDEN 115 1	1.27	Raise to 212F	201.6	201.6	$ 2.5
6GREENVIL230	3590	3	$ 3	$ 0.91	$ 2,012	$ 0.56	304473 PA-WASHINTON 230 304449 EDWARDS TAP 230 1	19.03	Raise to 212F	594	594	$ 38
6GREENVIL230	3605	15	$ 38	$ 2.54	$ 2,050	$ 0.57	304156 ROL/SQD TAP 230 304276 KNIGHT HODG 230 1	4.83	Raise to 212F	1084	1084	$ 10
8GREENVIL500	0						Interconnection	85	Interconnection from the Beach	-	-	$ 850
8GREENVIL500	1106	1106	$ 850	$ 0.77	$ 850	$ 0.77	304451 GREENVILE TT 230 314574 6EVERETS 230 1	22.21	Build Grnvl-Wom-Wake 500kV	-	-	$ 845
8GREENVIL500	1687	581	$ 845	$ 1.45	$ 1,695	$ 1.00	305997 8GREENVIL500 500 998836 GREENVILLE1 230 1	-	Add 2nd 500/230kV bank	1125	1125	$ 15
8GREENVIL500	2163	476	$ 15	$ 0.03	$ 1,710	$ 0.79	304451 GREENVILE TT 230 314574 6EVERETS 230 1	22.21	Reconductor to 6-1590 ACSR	1195	1195	$ 89
8GREENVIL500	2189	26	$ 89	$ 3.42	$ 1,799	$ 0.82	304451 GREENVILE TT 230 304452 GREENVILE W 230 1	4.1	Reconductor to 6-1590 ACSR	1195	1195	$ 16
8GREENVIL500	2286	97	$ 16	$ 0.17	$ 1,815	$ 0.79	304452 GREENVILE W 230 304229 PA-FARMVILLE 230 1	9.61	Reconductor to 6-1590 ACSR	1195	1195	$ 38
8GREENVIL500	2428	142	$ 38	$ 0.27	$ 1,854	$ 0.76	304229 PA-FARMVILLE 230 304228 WILSON230 TT 230 1	20.28	Reconductor to 6-1590 ACSR	1195	1195	$ 81
8GREENVIL500	2916	488	$ 81	$ 0.17	$ 1,935	$ 0.66	304451 GREENVILE TT 230 304445 CHOCOWINITY 230 1	18.61	Reconductor to 6-1590 ACSR	1195	1195	$ 74
8GREENVIL500	3070	155	$ 74	$ 0.48	$ 2,009	$ 0.65	306540 6MCGUIRE 230 306443 6MARSHAL 230 2	13.8	Reconductor already planned	-	-	$ 0
8GREENVIL500	3227	157	$ 0	$ 0.00	$ 2,009	$ 0.62	304445 CHOCOWINITY 230 304473 PA-WASHINTON 230 1	0.04	Reconductor to 6-1590 ACSR	1195	1195	$ 0.2
8GREENVIL500	3374	147	$ 0	$ 0.00	$ 2,010	$ 0.60	305997 8GREENVIL500 500 998836 GREENVILLE1 230 1	-	Larger transformers???	2000	2000	$ 10
8GREENVIL500	3419	45	$ 10	$ 0.22	$ 2,020	$ 0.59	304156 ROL/SQD TAP 230 304276 KNIGHT HODG 230 1	4.83	Raise to 212F	1084	1084	$ 10
8GREENVIL500	3576	157	$ 10	$ 0.06	$ 2,029	$ 0.57	304276 KNIGHT HODG 230 304162 MILBUR230 TT 230 1	2.19	Raise to 212F	1084	1084	$ 4
6NEWBERN230T	0						Interconnection	34	Interconnection from the Beach	n/a	n/a	$ 340
6NEWBERN230T	825	825	$ 340	$ 0.41	$ 340	$ 0.41	304465 NEWBERN230TT 230 304466 NEWBER115NTT 115 1	115	Build NewBern-Wom-Wake 500kV	-	-	$ 570
6NEWBERN230T	1006	181	$ 570	$ 3.15	$ 910	$ 0.90	304465 NEWBERN230TT 230 304466 NEWBER115NTT 115 1	-	Replace with 336 MVA	336	504	$ 4
6NEWBERN230T	1404	398	$ 4	$ 0.01	$ 914	$ 0.65	304465 NEWBERN230TT 230 304489 NEWBER115STT 115 2	-	Replace with 336 MVA	336	504	$ 4
6NEWBERN230T	1650	246	$ 4	$ 0.02	$ 918	$ 0.56	304489 NEWBER115STT 115 304466 NEWBER115NTT 115 Z1	-	Replace bus tie breaker	598	598	$ 1
6NEWBERN230T	2137	486	$ 1	$ 0.00	$ 919	$ 0.43	304465 NEWBERN230TT 230 304463 NEW BERN WES 230 1	1.02	Raise to 212F	594	594	$ 2
~~6NEWBERN230T~~	~~2198~~	~~61~~	~~$ 2~~	~~$ 0.03~~	~~$ 921~~	~~$ 0.42~~	~~304475~~ WEYER TAP 115 304477 VOA TAP 115 1	12.53	Add 2nd 500/230kV bank	1125	1125	$ 15

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6NEWBERN230T	2324	127	$ 15	$ 0.12	$ 936	$ 0.40	304475 WEYER TAP 115 304477 VOA TAP 115 1	12.53	Raise to 212F	202	202	$ 25
6NEWBERN230T	2372	48	$ 25	$ 0.52	$ 961	$ 0.41	304465 NEWBERN230TT 230 304506 DOVER 230 1	23.38	Raise to 212F	594	594	$ 47
6NEWBERN230T	2386	14	$ 47	$ 3.34	$ 1,008	$ 0.42	304477 VOA TAP 115 304480 KINSDUP115TT 115 1	10.94	Raise to 212F	202	202	$ 22
6NEWBERN230T	2393	7	$ 22	$ 3.13	$ 1,030	$ 0.43	304506 DOVER 230 304500 WOMMACK230TT 230 1	8.65	Raise to 212F	594	594	$ 17
6NEWBERN230T	2396	3	$ 17	$ 5.77	$ 1,047	$ 0.44	304463 NEW BERN WES 230 305142 E16-FAIRFELD 230 1	7.46	Raise to 212F	594	594	$ 15
6NEWBERN230T	2485	89	$ 15	$ 0.17	$ 1,062	$ 0.43	304466 NEWBER115NTT 115 304475 WEYER TAP 115 1	6.08	Raise to 212F	221	221	$ 12
6NEWBERN230T	2520	35	$ 12	$ 0.35	$ 1,074	$ 0.43	305142 E16-FAIRFELD 230 304434 BAYBORO TAP 230 1	8.53	Raise to 212F	594	594	$ 17
6NEWBERN230T	2631	111	$ 17	$ 0.15	$ 1,091	$ 0.41	304465 NEWBERN230TT 230 304484 HAVELOK230TT 230 1	23.47	Double Breaker New Bern 230	-	-	$ 4
6NEWBERN230T	2814	183	$ 4	$ 0.02	$ 1,095	$ 0.39	304465 NEWBERN230TT 230 304506 DOVER 230 1	23.38	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 47
6NEWBERN230T	2819	5	$ 47	$ 9.35	$ 1,142	$ 0.41	304434 BAYBORO TAP 230 304454 AURORA SS TT 230 1	10.74	Raise to 212F	594	594	$ 21
6NEWBERN230T	2835	16	$ 21	$ 1.34	$ 1,163	$ 0.41	304506 DOVER 230 304500 WOMMACK230TT 230 1	8.65	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 17
6NEWBERN230T	3031	196	$ 17	$ 0.09	$ 1,181	$ 0.39	306540 6MCGUIRE 230 306443 6MARSHAL 230 2	13.8	Reconductor already planned	-	-	$ 0
6NEWBERN230T	3101	70	$ 0	$ 0.00	$ 1,181	$ 0.38	304465 NEWBERN230TT 230 304484 HAVELOK230TT 230 1	23.47	Raise to 212F	594	594	$ 47
6NEWBERN230T	3252	151	$ 47	$ 0.31	$ 1,228	$ 0.38	304465 NEWBERN230TT 230 304500 WOMMACK230TT 230 1	33.87	Reconductor to 6-1590 ACSR	1195	1195	$ 135
6NEWBERN230T	3282	30	$ 135	$ 4.52	$ 1,363	$ 0.42	304465 NEWBERN230TT 230 304463 NEW BERN WES 230 1	1.02	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 2

8NEWBERN500	0						Interconnection	34	Interconnection from the Beach	n/a	n/a	$ 340
8NEWBERN500	825	825	$ 340	$ 0.41	$ 340	$ 0.41	304465 NEWBERN230TT 230 304466 NEWBER115NTT 115 1	115	Build NewBern-Wom-Wake 500kV	-	-	$ 570
8NEWBERN500	1687	862	$ 570	$ 0.66	$ 910	$ 0.54	305998 8NEWBERN500 500 998835 NEWBERN1 230 1	-	Add 2nd 500/230kV bank	1125	1687	$ 15
8NEWBERN500	1459	-228	$ 15	$ (0.07)	$ 925	$ 0.63	304465 NEWBERN230TT 230 304466 NEWBER115NTT 115 1	-	Replace with 336 MVA	336	504	$ 4
8NEWBERN500	2065	606	$ 4	$ 0.01	$ 929	$ 0.45	304465 NEWBERN230TT 230 304489 NEWBER115STT 115 2	-	Replace with 336 MVA	336	504	$ 4
8NEWBERN500	2372	307	$ 4	$ 0.01	$ 933	$ 0.39	304465 NEWBERN230TT 230 304506 DOVER 230 1	23.38	Raise to 212F	594	594	$ 47
8NEWBERN500	2393	21	$ 47	$ 2.23	$ 980	$ 0.41	304506 DOVER 230 304500 WOMMACK230TT 230 1	8.65	Raise to 212F	594	594	$ 17
8NEWBERN500	2413	20	$ 17	$ 0.87	$ 997	$ 0.41	304465 NEWBERN230TT 230 304463 NEW BERN WES 230 1	1.02	Raise to 212F	594	594	$ 2
8NEWBERN500	2434	21	$ 2	$ 0.10	$ 999	$ 0.41	304475 WEYER TAP 115 304477 VOA TAP 115 1	12.53	Raise to 212F	202	202	$ 25
8NEWBERN500	2440	6	$ 25	$ 4.18	$ 1,024	$ 0.42	304489 NEWBER115STT 115 304466 NEWBER115NTT 115 Z1	-	Replace bus tie breaker	598	598	$ 1
8NEWBERN500	2476	36	$ 1	$ 0.03	$ 1,025	$ 0.41	304477 VOA TAP 115 304480 KINSDUP115TT 115 1	10.94	Raise to 212F	202	202	$ 22
8NEWBERN500	2511	35	$ 22	$ 0.63	$ 1,047	$ 0.42	304463 NEW BERN WES 230 305142 E16-FAIRFELD 230 1	7.46	Raise to 212F	594	594	$ 15
8NEWBERN500	2545	34	$ 15	$ 0.44	$ 1,062	$ 0.42	304466 NEWBER115NTT 115 304475 WEYER TAP 115 1	6.08	Raise to 212F	221	221	$ 12
8NEWBERN500	2599	54	$ 12	$ 0.23	$ 1,074	$ 0.41	305142 E16-FAIRFELD 230 304434 BAYBORO TAP 230 1	8.53	Raise to 212F	594	594	$ 17
8NEWBERN500	2814	215	$ 17	$ 0.08	$ 1,091	$ 0.39	304465 NEWBERN230TT 230 304506 DOVER 230 1	23.38	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 47
8NEWBERN500	2819	5	$ 47	$ 9.35	$ 1,138	$ 0.40	304434 BAYBORO TAP 230 304454 AURORA SS TT 230 1	10.74	Raise to 212F	594	594	$ 21
8NEWBERN500	2835	16	$ 21	$ 1.34	$ 1,159	$ 0.41	304506 DOVER 230 304500 WOMMACK230TT 230 1	8.65	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 17
8NEWBERN500	3039	204	$ 17	$ 0.08	$ 1,177	$ 0.39	306540 6MCGUIRE 230 306443 6MARSHAL 230 2	13.8	Reconductor already planned	-	-	$ 0
8NEWBERN500	3252	213	$ 0	$ 0.00	$ 1,177	$ 0.36	304465 NEWBERN230TT 230 304500 WOMMACK230TT 230 1	33.87	Reconductor to 6-1590 ACSR	1195	1195	$ 135
8NEWBERN500	3282	30	$ 135	$ 4.52	$ 1,312	$ 0.40	304465 NEWBERN230TT 230 304463 NEW BERN WES 230 1	1.02	Reconductor to 6-1590 ACSR	1195	1195	$ 4
8NEWBERN500	3311	29	$ 4	$ 0.14	$ 1,316	$ 0.40	304454 AURORA SS TT 230 304449 EDWARDS TAP 230 1	0.96	Raise to 212F	594	594	$ 2
8NEWBERN500	3374	63	$ 2	$ 0.03	$ 1,318	$ 0.39	305998 8NEWBERN500 500 998833 NEWBERN2 230 2	-	Larger transformers???	2000	2000	$ 10
8NEWBERN500	3390	16	$ 10	$ 0.63	$ 1,328	$ 0.39	304449 EDWARDS TAP 230 304473 PA-WASHINTON 230 1	19.03	Raise to 212F	594	594	$ 38
8NEWBERN500	3403	13	$ 38	$ 2.93	$ 1,366	$ 0.40	304251 LEESUB230 TT 230 304192 SELMA 230 TT 230 1	16.78	Ancillary equipment	940	940	$ 1
8NEWBERN500	3445	42	$ 1	$ 0.01	$ 1,367	$ 0.40	304465 NEWBERN230TT 230 304484 HAVELOK230TT 230 1	23.47	Raise to 212F	594	594	$ 47

Avangrid Renewables LLC
Transmission Panel Direct Cross-Examination
Exhibit No. 1

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
8NEWBERN500	3467	22	$ 47	$ 2.13	$ 1,414	$ 0.41	304378 RICHMON230TT 230 304348 ROCKHAM230TT 230 1	5.96	Raise to 212F	1084	1084	$ 12
8NEWBERN500	3468	1	$ 12	$ 11.92	$ 1,426	$ 0.41	305142 E16-FAIRFELD 230 304434 BAYBORO TAP 230 1	8.53	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 17
8NEWBERN500	3541	73	$ 17	$ 0.23	$ 1,443	$ 0.41	304156 ROL/SQD TAP 230 304276 KNIGHT HODG 230 1	4.83	Raise to 212F	1084	1084	$ 10
8NEWBERN500	3555	14	$ 10	$ 0.69	$ 1,452	$ 0.41	304445 CHOCOWINITY 230 304451 GREENVILE TT 230 1	18.57	Raise to 212F	482	482	$ 37
6SUTNORTH230-Cumb	0						Interconnection	17	Interconnection from the Beach	n/a	n/a	$ 170
6SUTNORTH230-Cumb	695	695	$ 170	$ 0.24	$ 170	$ 0.24	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	-	Build SuttNorth-Cumberland 500kV	-	-	$ 660
6SUTNORTH230-Cumb	1147	452	$ 660	$ 1.46	$ 830	$ 0.72	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	-	Add 2nd 500/230kV bank	1125	1687	$ 15
6SUTNORTH230-Cumb	1256	109	$ 15	$ 0.14	$ 845	$ 0.67	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Raise to 212F	594	594	$ 7
6SUTNORTH230-Cumb	1530	274	$ 7	$ 0.03	$ 852	$ 0.56	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Raise to 212F	594	594	$ 9
6SUTNORTH230-Cumb	1663	133	$ 9	$ 0.07	$ 861	$ 0.52	305995 6SUTNORTH230 230 305470 WILARDSOLTAP 230 1	19	Raise to 212F	594	594	$ 38
6SUTNORTH230-Cumb	1961	298	$ 38	$ 0.13	$ 899	$ 0.46	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Raise to 212F	594	594	$ 55
6SUTNORTH230-Cumb	2005	44	$ 55	$ 1.25	$ 954	$ 0.48	304378 RICHMON230TT 230 304348 ROCKHAM230TT 230 1	5.96	Raise to 212F	1084	1084	$ 12
6SUTNORTH230-Cumb	2113	108	$ 12	$ 0.11	$ 966	$ 0.46	305995 6SUTNORTH230 230 304354 ROCKY POINT 230 1	8.2	Reconductor to 6-1590 ACSR	1195	1195	$ 33
6SUTNORTH230-Cumb	2131	18	$ 33	$ 1.82	$ 999	$ 0.47	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Raise to 212F	594	594	$ 2
6SUTNORTH230-Cumb	2146	15	$ 2	$ 0.16	$ 1,001	$ 0.47	304039 SUTTON230 TT 230 304554 WILM N&O TAP 230 1	5.38	Reconductor to 6-1590 ACSR	1195	1195	$ 22
6SUTNORTH230-Cumb	2179	33	$ 22	$ 0.65	$ 1,023	$ 0.47	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 55
6SUTNORTH230-Cumb	2190	11	$ 55	$ 5.00	$ 1,078	$ 0.49	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Raise to 212F	594	594	$ 4
6SUTNORTH230-Cumb	2190	0	$ 4	#DIV/0!	$ 1,081	$ 0.49	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 7
6SUTNORTH230-Cumb	2258	68	$ 7	$ 0.11	$ 1,088	$ 0.48	304354 ROCKY POINT 230 305069 E9-MEADOW 230 1	34.95	Reconductor to 6-1590 ACSR	1195	1195	$ 140
6SUTNORTH230-Cumb	2272	14	$ 140	$ 9.99	$ 1,228	$ 0.54	304503 WARSAW TAP 230 304205 CLINTON230TT 230 1	12.6	Reconductor to 6-1590 ACSR	1195	1195	$ 50
6SUTNORTH230-Cumb	2322	50	$ 50	$ 1.01	$ 1,279	$ 0.55	305032 E4-BLIND BRG 230 304503 WARSAW TAP 230 1	12.67	Reconductor to 6-1590 ACSR	1195	1195	$ 51
6SUTNORTH230-Cumb	2410	88	$ 51	$ 0.58	$ 1,329	$ 0.55	305069 E9-MEADOW 230 304524 JACKSON230TT 230 1	4.78	Reconductor to 6-1590 ACSR	1195	1195	$ 19
6SUTNORTH230-Cumb	2413	3	$ 19	$ 6.37	$ 1,348	$ 0.56	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Raise to 212F	594	594	$ 4
6SUTNORTH230-Cumb	2437	24	$ 4	$ 0.17	$ 1,352	$ 0.55	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Raise to 212F	594	594	$ 1
6SUTNORTH230-Cumb	2453	16	$ 1	$ 0.05	$ 1,353	$ 0.55	304020 BRUN2 230 TT 230 305004 E1-PROSPECT 230 1	19.31	Raise to 212F	594	594	$ 39
6SUTNORTH230-Cumb	2462	9	$ 39	$ 4.29	$ 1,392	$ 0.57	304582 DELCO230 TT 230 304587 DELCO115W TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6SUTNORTH230-Cumb	2464	2	$ 4	$ 2.00	$ 1,396	$ 0.57	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 9
6SUTNORTH230-Cumb	2512	48	$ 9	$ 0.18	$ 1,404	$ 0.56	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 2
6SUTNORTH230-Cumb	2512	0	$ 2	#DIV/0!	$ 1,407	$ 0.56	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 4
6SUTNORTH230-Cumb	2514	2	$ 4	$ 1.99	$ 1,411	$ 0.56	304515 WALLACE230TT 230 305031 E4-BEVERAGE 230 1	6.54	Reconductor to 6-1590 ACSR	1195	1195	$ 26
6SUTNORTH230-Cumb	2536	22	$ 26	$ 1.19	$ 1,437	$ 0.57	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 1
6SUTNORTH230-Cumb	2536	0	$ 1	#DIV/0!	$ 1,438	$ 0.57	304378 RICHMON230TT 230 304348 ROCKHAM230TT 230 1	5.96	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 12
8SUTNORTH500-Cumb	0						Interconnection	17	Interconnection from the Beach	n/a	n/a	$ 170
8SUTNORTH500-Cumb	695	695	$ 170	$ 0.24	$ 170	$ 0.24	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	-	Build SuttNorth-Cumberland 500kV	-	-	$ 660
8SUTNORTH500-Cumb	1687	992	$ 660	$ 0.67	$ 830	$ 0.49	305996 8SUTNORTH500 500 998836 SUTTONNORTH1 230 1	-	Add 2nd 500/230kV bank	1125	1687	$ 15
8SUTNORTH500-Cumb	1624	-63	$ 15	$ (0.24)	$ 845	$ 0.52	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Raise to 212F	594	594	$ 7
8SUTNORTH500-Cumb	1890	266	$ 7	$ 0.03	$ 852	$ 0.45	304378 RICHMON230TT 230 304348 ROCKHAM230TT 230 1	5.96	Raise to 212F	1084	1084	$ 12
8SUTNORTH500-Cumb	1930	40	$ 12	$ 0.30	$ 864	$ 0.45	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Raise to 212F	594	594	$ 9

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
8SUTNORTH500-Cumb	2045	115	$ 9	$ 0.08	$ 873	$ 0.43	305995 6SUTNORTH230 230 305470 WILARDSOLTAP 230 1	19	Raise to 212F	594	594	$ 38
8SUTNORTH500-Cumb	2131	86	$ 38	$ 0.44	$ 911	$ 0.43	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Raise to 212F	594	594	$ 2
8SUTNORTH500-Cumb	2190	59	$ 2	$ 0.04	$ 913	$ 0.42	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Raise to 212F	594	594	$ 4
8SUTNORTH500-Cumb	2272	82	$ 4	$ 0.04	$ 917	$ 0.40	304503 WARSAW TAP 230 304205 CLINTON230TT 230 1	12.6	Reconductor to 6-1590 ACSR	1195	1195	$ 50
8SUTNORTH500-Cumb	2322	50	$ 50	$ 1.01	$ 967	$ 0.42	305032 E4-BLIND BRG 230 304503 WARSAW TAP 230 1	12.67	Reconductor to 6-1590 ACSR	1195	1195	$ 51
8SUTNORTH500-Cumb	2391	69	$ 51	$ 0.73	$ 1,018	$ 0.43	304378 RICHMON230TT 230 304348 ROCKHAM230TT 230 1	5.96	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 12
8SUTNORTH500-Cumb	2413	22	$ 12	$ 0.54	$ 1,030	$ 0.43	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Raise to 212F	594	594	$ 4
8SUTNORTH500-Cumb	2437	24	$ 4	$ 0.17	$ 1,034	$ 0.42	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Raise to 212F	594	594	$ 1
8SUTNORTH500-Cumb	2453	16	$ 1	$ 0.05	$ 1,035	$ 0.42	304020 BRUN2 230 TT 230 305004 E1-PROSPECT 230 1	19.31	Raise to 212F	594	594	$ 39
8SUTNORTH500-Cumb	2498	45	$ 39	$ 0.86	$ 1,073	$ 0.43	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 7
8SUTNORTH500-Cumb	2513	15	$ 7	$ 0.48	$ 1,080	$ 0.43	304515 WALLACE230TT 230 305031 E4-BEVERAGE 230 1	6.54	Reconductor to 6-1590 ACSR	1195	1195	$ 26
8SUTNORTH500-Cumb	2516	3	$ 26	$ 8.72	$ 1,107	$ 0.44	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 2
8SUTNORTH500-Cumb	2516	0	$ 2	#DIV/0!	$ 1,109	$ 0.44	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 4
8SUTNORTH500-Cumb	2527	11	$ 4	$ 0.36	$ 1,113	$ 0.44	305530 TRNBLSOLTAP 230 304390 CUMBLND230TT 230 1	9.56	Ancillary equipment	512	512	$ 0
8SUTNORTH500-Cumb	2535	8	$ 0	$ 0.03	$ 1,113	$ 0.44	304039 SUTTON230 TT 230 304554 WILM N&O TAP 230 1	5.38	Reconductor to 6-1590 ACSR	1195	1195	$ 22
8SUTNORTH500-Cumb	2540	5	$ 22	$ 4.30	$ 1,135	$ 0.45	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 1
8SUTNORTH500-Cumb	2575	35	$ 1	$ 0.02	$ 1,135	$ 0.44	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 4
8SUTNORTH500-Cumb	2597	22	$ 4	$ 0.16	$ 1,139	$ 0.44	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Raise to 212F	594	594	$ 55
8SUTNORTH500-Cumb	2633	36	$ 55	$ 1.53	$ 1,194	$ 0.45	305995 6SUTNORTH230 230 304354 ROCKY POINT 230 1	8.2	Reconductor to 6-1590 ACSR	1195	1195	$ 33
8SUTNORTH500-Cumb	2692	59	$ 33	$ 0.56	$ 1,227	$ 0.46	304020 BRUN2 230 TT 230 305004 E1-PROSPECT 230 1	19.31	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 39
8SUTNORTH500-Cumb	2731	39	$ 39	$ 0.99	$ 1,265	$ 0.46	305530 TRNBLSOLTAP 230 304390 CUMBLND230TT 230 1	9.56	Raise to 212F	542	542	$ 19
8SUTNORTH500-Cumb	2732	1	$ 19	$ 19.12	$ 1,285	$ 0.47	304505 ROSE HILL 230 305032 E4-BLIND BRG 230 1	4.58	Reconductor to 6-1590 ACSR	1195	1195	$ 18
8SUTNORTH500-Cumb	2735	3	$ 18	$ 6.11	$ 1,303	$ 0.48	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 9
8SUTNORTH500-Cumb	2753	18	$ 9	$ 0.49	$ 1,312	$ 0.48	304354 ROCKY POINT 230 305069 E9-MEADOW 230 1	34.95	Reconductor to 6-1590 ACSR	1195	1195	$ 140
8SUTNORTH500-Cumb	2816	63	$ 140	$ 2.22	$ 1,451	$ 0.52	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 55
8SUTNORTH500-Cumb	2850	34	$ 55	$ 1.62	$ 1,506	$ 0.53	306540 6MCGUIRE 230 306443 6MARSHAL 230 2	13.8	Reconductor already planned	-	-	$ 0

6SUTNORTH230-Wom	0						Interconnection	17	Interconnection from the Beach	n/a	n/a	$ 170
6SUTNORTH230-Wom	695	695	$ 170	$ 0.24	$ 170	$ 0.24	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	-	Build SuttNorth-Wom-Wake 500kV	-	-	$ 1,110
6SUTNORTH230-Wom	1545	850	$ 1,110	$ 1.31	$ 1,280	$ 0.83	305996 8SUTNORTH500 500 998836 SUTTONNORTH1 230 1	-	Add 2nd 500/230kV bank	1125	1687	$ 15
6SUTNORTH230-Wom	1689	144	$ 15	$ 0.10	$ 1,295	$ 0.77	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Raise to 212F	594	594	$ 7
6SUTNORTH230-Wom	1923	234	$ 7	$ 0.03	$ 1,302	$ 0.68	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Raise to 212F	594	594	$ 9
6SUTNORTH230-Wom	2037	114	$ 9	$ 0.08	$ 1,311	$ 0.64	305995 6SUTNORTH230 230 305470 WILARDSOLTAP 230 1	19	Raise to 212F	594	594	$ 38
6SUTNORTH230-Wom	2140	103	$ 38	$ 0.37	$ 1,349	$ 0.63	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Raise to 212F	594	594	$ 2
6SUTNORTH230-Wom	2200	60	$ 2	$ 0.04	$ 1,351	$ 0.61	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Raise to 212F	594	594	$ 4
6SUTNORTH230-Wom	2273	73	$ 4	$ 0.05	$ 1,355	$ 0.60	304503 WARSAW TAP 230 304205 CLINTON230TT 230 1	12.6	Reconductor to 6-1590 ACSR	1195	1195	$ 50
6SUTNORTH230-Wom	2280	7	$ 50	$ 7.20	$ 1,405	$ 0.62	304582 DELCO230 TT 230 304587 DELCO115W TT 115 1	-	Replace with 336 MVA	336	427	$ 4
6SUTNORTH230-Wom	2325	45	$ 4	$ 0.09	$ 1,409	$ 0.61	305032 E4-BLIND BRG 230 304503 WARSAW TAP 230 1	12.67	Reconductor to 6-1590 ACSR	1195	1195	$ 51
6SUTNORTH230-Wom	2349	24	$ 51	$ 2.11	$ 1,460	$ 0.62	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Raise to 212F	594	594	$ 55
6SUTNORTH230-Wom	2421	72	$ 55	$ 0.76	$ 1,515	$ 0.63	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Raise to 212F	594	594	$ 4
6SUTNORTH230-Wom	2445	24	$ 4	$ 0.17	$ 1,519	$ 0.62	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Raise to 212F	594	594	$ 1

Avangrid Renewables LLC
Transmission Panel Direct Cross-Examination
Exhibit No. 1

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element	Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
6SUTNORTH230-Wom	2486	41	$ 1	$ 0.02	$ 1,520	$ 0.61	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 7
6SUTNORTH230-Wom	2492	6	$ 7	$ 1.19	$ 1,527	$ 0.61	304020 BRUN2 230 TT 230 305004 E1-PROSPECT 230 1	19.31	Raise to 212F	594	594	$ 39
6SUTNORTH230-Wom	2518	26	$ 39	$ 1.49	$ 1,566	$ 0.62	304515 WALLACE230TT 230 305031 E4-BEVERAGE 230 1	6.54	Reconductor to 6-1590 ACSR	1195	1195	$ 26
6SUTNORTH230-Wom	2525	7	$ 26	$ 3.74	$ 1,592	$ 0.63	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 2
6SUTNORTH230-Wom	2549	24	$ 2	$ 0.10	$ 1,594	$ 0.63	304039 SUTTON230 TT 230 304554 WILM N&O TAP 230 1	5.38	Reconductor to 6-1590 ACSR	1195	1195	$ 22
6SUTNORTH230-Wom	2575	26	$ 22	$ 0.83	$ 1,616	$ 0.63	305530 TRNBLSOLTAP 230 304390 CUMBLND230TT 230 1	9.56	Raise to 212F	512	512	$ 19
6SUTNORTH230-Wom	2585	10	$ 19	$ 1.91	$ 1,635	$ 0.63	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 4
6SUTNORTH230-Wom	2596	11	$ 4	$ 0.33	$ 1,638	$ 0.63	305995 6SUTNORTH230 230 304354 ROCKY POINT 230 1	8.2	Reconductor to 6-1590 ACSR	1195	1195	$ 33
6SUTNORTH230-Wom	2709	113	$ 33	$ 0.29	$ 1,671	$ 0.62	304354 ROCKY POINT 230 305069 E9-MEADOW 230 1	34.95	Reconductor to 6-1590 ACSR	1195	1195	$ 140
6SUTNORTH230-Wom	2720	11	$ 140	$ 12.71	$ 1,811	$ 0.67	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 9
6SUTNORTH230-Wom	2731	11	$ 9	$ 0.80	$ 1,820	$ 0.67	304587 DELCO115W TT 115 304575 LAKE WACCA 115 1	16.86	Reconductor to 3-1590 ACSR	340	340	$ 67
6SUTNORTH230-Wom	2739	8	$ 67	$ 8.43	$ 1,887	$ 0.69	304505 ROSE HILL 230 305032 E4-BLIND BRG 230 1	4.58	Reconductor to 6-1590 ACSR	1195	1195	$ 18
6SUTNORTH230-Wom	2822	83	$ 18	$ 0.22	$ 1,906	$ 0.68	305069 E9-MEADOW 230 304524 JACKSON230TT 230 1	4.78	Reconductor to 6-1590 ACSR	1195	1195	$ 19
6SUTNORTH230-Wom	2824	2	$ 19	$ 9.56	$ 1,925	$ 0.68	304525 JACKSN115ETT 115 305065 E9-GUMBRNCH 115 1	4.69	Reconductor to 3-1590 ACSR	340	340	$ 19

8SUTNORTH500-Wom	0						Interconnection	17	Interconnection from the Beach	n/a	n/a	$ 170
8SUTNORTH500-Wom	695	695	$ 170	$ 0.24	$ 170	$ 0.24	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	-	Build SuttNorth-Wom-Wake 500kV	-	-	$ 1,110
8SUTNORTH500-Wom	1687	992	$ 1,110	$ 1.12	$ 1,280	$ 0.76	305996 8SUTNORTH500 500 998836 SUTTONNORTH1 230 1	-	Add 2nd 500/230kV bank	1125	1687	$ 15
8SUTNORTH500-Wom	1689	2	$ 15	$ 7.50	$ 1,295	$ 0.77	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Raise to 212F	594	594	$ 7
8SUTNORTH500-Wom	1923	234	$ 7	$ 0.03	$ 1,302	$ 0.68	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Raise to 212F	594	594	$ 9
8SUTNORTH500-Wom	2037	114	$ 9	$ 0.08	$ 1,311	$ 0.64	305995 6SUTNORTH230 230 305470 WILARDSOLTAP 230 1	19	Raise to 212F	594	594	$ 38
8SUTNORTH500-Wom	2140	103	$ 38	$ 0.37	$ 1,349	$ 0.63	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Raise to 212F	594	594	$ 2
8SUTNORTH500-Wom	2200	60	$ 2	$ 0.04	$ 1,351	$ 0.61	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Raise to 212F	594	594	$ 4
8SUTNORTH500-Wom	2273	73	$ 4	$ 0.05	$ 1,355	$ 0.60	304503 WARSAW TAP 230 304205 CLINTON230TT 230 1	12.6	Reconductor to 6-1590 ACSR	1195	1195	$ 50
8SUTNORTH500-Wom	2324	51	$ 50	$ 0.99	$ 1,405	$ 0.60	305032 E4-BLIND BRG 230 304503 WARSAW TAP 230 1	12.67	Reconductor to 6-1590 ACSR	1195	1195	$ 51
8SUTNORTH500-Wom	2425	101	$ 51	$ 0.50	$ 1,456	$ 0.60	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Raise to 212F	594	594	$ 4
8SUTNORTH500-Wom	2450	25	$ 4	$ 0.16	$ 1,460	$ 0.60	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Raise to 212F	594	594	$ 1
8SUTNORTH500-Wom	2482	32	$ 1	$ 0.02	$ 1,461	$ 0.59	305880 CROOKDSOLTAP 230 304515 WALLACE230TT 230 1	3.57	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 7
8SUTNORTH500-Wom	2483	1	$ 7	$ 7.14	$ 1,468	$ 0.59	304020 BRUN2 230 TT 230 305004 E1-PROSPECT 230 1	19.31	Raise to 212F	594	594	$ 39
8SUTNORTH500-Wom	2517	34	$ 39	$ 1.14	$ 1,507	$ 0.60	304515 WALLACE230TT 230 305031 E4-BEVERAGE 230 1	6.54	Reconductor to 6-1590 ACSR	1195	1195	$ 26
8SUTNORTH500-Wom	2528	11	$ 26	$ 2.38	$ 1,533	$ 0.61	304039 SUTTON230 TT 230 304554 WILM N&O TAP 230 1	5.38	Reconductor to 6-1590 ACSR	1195	1195	$ 22
8SUTNORTH500-Wom	2529	1	$ 22	$ 21.52	$ 1,554	$ 0.61	305995 6SUTNORTH230 230 304516 WILM BASF 230 1	1.22	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 2
8SUTNORTH500-Wom	2529	0	$ 2	#DIV/0!	$ 1,557	$ 0.62	304516 WILM BASF 230 304534 WILM PRAX 230 1	1.99	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 4
8SUTNORTH500-Wom	2554	25	$ 4	$ 0.16	$ 1,561	$ 0.61	304534 WILM PRAX 230 304520 WILM INVISTA 230 1	0.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 1
8SUTNORTH500-Wom	2564	10	$ 1	$ 0.08	$ 1,561	$ 0.61	305530 TRNBLSOLTAP 230 304390 CUMBLND230TT 230 1	9.56	Raise to 212F	512	512	$ 19
8SUTNORTH500-Wom	2584	20	$ 19	$ 0.96	$ 1,581	$ 0.61	305995 6SUTNORTH230 230 304515 WALLACE230TT 230 1	27.5	Raise to 212F	594	594	$ 55
8SUTNORTH500-Wom	2589	5	$ 55	$ 11.00	$ 1,636	$ 0.63	304520 WILM INVISTA 230 304039 SUTTON230 TT 230 1	1.79	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 4
8SUTNORTH500-Wom	2593	4	$ 4	$ 0.90	$ 1,639	$ 0.63	305995 6SUTNORTH230 230 304354 ROCKY POINT 230 1	8.2	Reconductor to 6-1590 ACSR	1195	1195	$ 33
8SUTNORTH500-Wom	2706	113	$ 33	$ 0.29	$ 1,672	$ 0.62	304354 ROCKY POINT 230 305069 E9-MEADOW 230 1	34.95	Reconductor to 6-1590 ACSR	1195	1195	$ 140
8SUTNORTH500-Wom	2717	11	$ 140	$ 12.71	$ 1,812	$ 0.67	305470 WILARDSOLTAP 230 305880 CROOKDSOLTAP 230 1	4.39	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 9
8SUTNORTH500-Wom	2729	12	$ 9	$ 0.73	$ 1,821	$ 0.67	304020 BRUN2 230 TT 230 305004 E1-PROSPECT 230 1	19.31	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 39

POI	MW Limit	Increm. MW	Increm Cost ($M)	Increm. Cost ($/W)	Total Cost ($M)	Total Cost ($/W)	Limiting Element						Miles	Upgrade	New Rate A	New Rate B	Increm Cost ($M)
8SUTNORTH500-Wom	2737	8	$ 39	$ 4.83	$ 1,859	$ 0.68	304505 ROSE HILL	230	305032 E4-BLIND BRG	230	1		4.58	Reconductor to 6-1590 ACSR	1195	1195	$ 18
8SUTNORTH500-Wom	2780	43	$ 18	$ 0.43	$ 1,877	$ 0.68	304582 DELCO230 TT	230	304587 DELCO115W TT	115	1		-	Replace with 336 MVA	336	427	$ 4
8SUTNORTH500-Wom	2803	23	$ 4	$ 0.17	$ 1,881	$ 0.67	305995 6SUTNORTH230	230	304515 WALLACE230TT	230	1		27.5	Reconductor to 6-1590 ACSR instead of raise	1195	1195	$ 55
8SUTNORTH500-Wom	2822	19	$ 55	$ 2.89	$ 1,936	$ 0.69	305069 E9-MEADOW	230	304524 JACKSON230TT	230	1		4.78	Reconductor to 6-1590 ACSR	1195	1195	$ 19
8SUTNORTH500-Wom	2824	2	$ 19	$ 9.56	$ 1,956	$ 0.69	304525 JACKSN115ETT	115	305065 E9-GUMBRNCH	115	1		4.69	Reconductor to 3-1590 ACSR	340	340	$ 19

Appendix B
Transmission Upgrade Costs Used in This Study

$M	Description
$2	per mile to raise clearances
$4	per mile to reconductor
$5	per mile for interconnection/green field line
$10	per mile for 500kV (incl. purchase of ROW)
$5	per mile for 500kV (ROW already owned)
$4	to replace 230/115kV transformer
$7	to install 230/115kV transformer in new position
$15	to install 500/230kV transformer in new position
$25	to build Sutton North 230kV

	Sutton North - Wommack - Wake 500kV	miles
$25	to build Sutton North 230kV	
$35	for Sutton 500kV switchyard	
$35	for Wommack 500kV switchyard	
$690	Sutton-Wommack 500kV line	69
$325	Wommack-Wake 500kV line	65
$1,110		

	Sutton North - Cumberland 500kV	miles
$25	to build Sutton North 230kV	
$35	for Sutton 500kV switchyard	
$600	Sutton-Cumberland 500kV line	60
$660		

	New Bern - Wommack - Wake 500kV	miles
$35	for New Bern 500kV switchyard	
$35	for Wommack 500kV switchyard	
$175	New Bern-Wommack 500kV line	35
$325	Wommack-Wake 500kV line	65
$570		

	Greenville - Wommack - Wake 500kV	miles
$35	for Greenville 500kV switchyard	
$35	for Wommack 500kV switchyard	
$450	Greenville-Wommack 500kV line	45
$325	Wommack-Wake 500kV line	65
$845		

Appendix C

Mileages from Substations to Coastline Used in This Study

POI Station	Miles from Coast
6AURORASST	46
6BRUN1230T	5
6BRUN2230T	5
6CASTLEH230T	9
6CLINTON230T	60
6CUMBLND230T	72
6DELCO230T	30
6FLOSUB230T	64
6FOLKSTN230T	10
6GREENVIL230	85
6GRNTSCK230T	14
6HAVELOK230T	4
6JACKSON230T	20
6KINDUP230TT	30
6KINGSTR230T	45
6LANDSTN	8
6LATTASST	53
6LEESUB230T	70
6MARION230T	46
6MORHDWW230T	4
6MTOLV230T	62
6NEWBERN230T	34
6SUMTER230T	75
6SUTNORTH230	17
6WAKE230TT	90
6WALLACE230T	32
6WHITEVL230T	34
6WOMMACK230T	51
6WSPOON230T	58
8CUMBLND500T	72
8FENTRES	15
8GREENVIL500	85
8NEWBERN500	34
8WAKE500TT	90

I/A

CPSA
Docket No. E-100, Sub 179
2022 Carbon Plan
CPSA Data Request No. 3
Item No. 3-10
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

On page 71-21, the Modeling Panel testifies that "the only SPS contract structures the Companies have used to date do not enable the flexibility and operation control modeled here. Substantial work is required to evaluate the extent to which it is possible to ensure that actual operations of solar paired with battery storage match the modeling assumptions for this resource." Please describe in detail all work performed or commissioned by the Companies to devise contract structures of the type described in the cited testimony, or to "evaluate the extent to which it is possible to ensure that actual operations of solar paired with battery storage match the modeling assumptions for this resource."

RESPONSE:

Duke Energy objects to this request to the extent it seeks attorney work product or privileged communications. Notwithstanding the foregoing, to date, the Companies have not developed alternative contract structures that would enable the flexibility and operational control of the SPS resource as modeled in the Carbon Plan. The Companies plan to benchmark RFPs for SPS resources in other jurisdictions, as well as to engage with market participants and other interested stakeholders to assess optimal contract structures that would provide Duke Energy the necessary capability to dispatch, operate, and control the facility. As stated on page 72," Duke Energy will be working with stakeholders in advance of the 2023 procurement to assess potential commercial contract terms and conditions for leasing third-party owned SPS assets in a manner that replicates the operational characteristics, as well as qualitative benefits and risks, of Company owned SPS assets over the life of the contract"

Responder: Matthew Kalemba, Director DET Planning & Forecasting

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

With the likely need for transmission upgrades from renewables procurement, the 2022 Solar Request for Proposals, and Duke's ownership percentage specified in HB 951, please answer the following questions:

Note: The intention of the following questions is to begin identifying existing rules that will impact successful implementation of HB 951, as well as any new rules or rule revisions that may be necessary for successful implementation.

a. R8-60, Transmission Facilities. Given the differences between DEC and DEP's transmission voltages and the potential for DEC to interconnect solar (or other resources) on the 100 kV system, should the voltage level in this requirement be evaluated and changed? How does Duke plan to demonstrate to regulatory bodies that its transmission planning is adequate and least cost?
   i. How does Duke plan on updating the impact to ratepayer costs for individual utilities with varying degrees of transmission build-out over the short- and long term?
b. First Year of Need Given the requirements of HB 951, does the Company consider how the first year of need will be impacted?
c. R8-60 Reserve Margins. Please explain how Duke is planning to calculate and apply the reserve margin to individual utilities if it pursues a combined balancing area and larger future procurements of generation.
   i. Would higher amounts of intermittent generation, or generation not aligned with the winter peak, cause an individual utility to have an increase, or even decrease, in the target reserve margin?
d. R8-61, preliminary plans and filing requirements. R8-61 specifies a 300 MW or greater nameplate rating for pre-filing; how does Duke plan to meet the 120-day requirement before filing an application given the potential for RFPs and DISIS timelines?
   i. Does the Company plan to ask for a waiver of R8-61 under the solar RFPs?
   ii. Should the 300 MW minimum be modified to a different amount such as 80 MW or 600 MW?
   iii. For Exhibit 5, should the rule also be modified to capture natural gas generation plants and not just coal and nuclear?

REQUEST (cont.):

e. R8-62, CECPCN for transmission. Please explain how Duke plans to mitigate the risk of a solar facility that is optimally selected and requires a R8-62 CECPCN for transmission, but the CECPCN is denied or changed (noting that changes in the CECPCN may alter project ranking). Potential risk factors may occur after the project ranking, and selection of resources may inhibit the Company from meeting its HB 951 targets.
   i. Should the RFPs and PPAs have conditional language to address the risk of a CECPCN not being granted, or if the routing materially changes and causes delays or increases in costs?
f. R8-63 and R8-64, CPCNs for Merchant Plants or Qualifying Facilities. Merchant Plants and QF generators without approved CPCNs will likely be in the Solar RFPs and may be selected with direct sell (build-own-transfer or equivalent) to Duke. What Rule changes could be implemented to mitigate the risk of a CPCN being denied after the Solar RFP has concluded?
   i. Should the RFPs and PPAs have conditional language to address the risk of a CPCN not being granted?

RESPONSE:

The Companies appreciate the Public Staff raising the need to evaluate resource planning, siting and related Commission rules that should be updated to facilitate North Carolina's evolving Carbon Plan-informed resource planning process. As highlighted in the Companies' Petition for Approval of the Carbon Plan and restated in the Executive Summary, Duke Energy supports pursuing such rulemaking later this year and has asked the Commission to direct the Companies and Public Staff to develop and propose for comment by January 31, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan. The Companies' responses below present preliminary assessments of rule changes that are subject to further refinement based upon future discussion with the Public Staff or other factors.

a. R8-60, Transmission Facilities.

As presented in Appendix P (Transmission System Planning and Grid Transformation), Duke Energy is supportive of providing more expansive information on transmission facilities that are planned or under construction than in past IRPs. Table P-2 includes transmission facilities planned or under construction sized 100 kV and above that are planned or under construction in addition to the information required by current IRP Rule R8-60(I)(5). Appendix P to the Carbon Plan beginning on Page 4 addresses the Companies' transmission planning process and how it is designed to ensure system adequacy and reliability as well as continued cost-effective and high-quality service for customers. Duke Energy does not foresee that any changes to the IRP rule are needed relating to the Companies' FERC-jurisdictional transmission planning process.

i. Appendix E, Table E-44 reflects transmission network upgrade cost proxies for different resources considered in the Carbon Plan. These network upgrade proxy costs are aggregated based on the Carbon Plan resources selected, and these aggregated costs are considered in estimating the rate impacts for the customer. In future updates to the filed Carbon Plan, these transmission network upgrade cost proxies will be revised to reflect the latest transmission network upgrade projects identified through transmission planning studies to be needed for interconnection of planned Carbon Plan resources.

Responder: Sammy Roberts, General Manager - Transmission Planning and Operations Strategy

b. First Year of Need

The first year of resource need as determined and defined in the 2020 IRP has not been calculated for any of the Carbon Plan portfolios at this time. However, first year of undesignated capacity need will continue to be an important issue that should be addressed in future IRPs.

Responder: Jennifer Canipe, P.E., Lead Engineer

c. R8-60 Reserve Margins.

Note that this response is written from the consolidated system operations (one balancing authority) perspective and does not address other potential costs and benefits associated with a full merger of the DEC and DEP systems.

Ensuring reasonable and sufficient reserve margins will continue to be important resource planning metrics in future Carbon Plans and IRPs. As described in Appendix R (Consolidated System Operations), a benefit of the consolidated system operations project is improved reliability in conjunction with CO2 carbon reduction objectives. Consolidated system operations will enable a reduction in risk to meet a one day in 10-year loss of load probability (LOLP), also known in the industry as loss of load expectation (LOLE). Defined at the highest level, risk is simply the probability of an adverse event occurrence combined with the consequence severity of such event should it occur. The one day in 10-year standard (LOLP of 0.1 or LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed (the consequence severity) every 10 years due to a shortage of generating capacity and is used across the industry to set minimum target reserve margin levels. For Duke Energy, as separate Balancing Authorities (BA), the risk for each BA to meet the 0.1 LOLE reliability metric independently is higher as compared with planning to meet this reliability metric as one consolidated BA with consolidated functions. This reduction in risk is due to the ability of the consolidated system operations to dedicate operating reserves to serving the consolidated BA demand during seasonal extreme peak scenarios. With the reduction in risk associated with meeting the 0.1 LOLE, this effectively lowers the necessary planning reserve margin.

It is important to note that the current 17% winter reserve margin target is based on the 2020 Resource Adequacy Study combined case which allows preferential support between DEC and DEP to approximate the reliability benefits of operating the DEC and DEP generation systems as a single BA (the DEC and DEP 2020 Resource Adequacy Study reports are included as Attachments I and II to the Carbon Plan). Thus, some reliability benefit of operating as a single BA is already reflected in the current reserve margin target. However, as noted above, there is likely additional reliability benefit associated with maintaining a lower level of operating reserves for the combined BA versus the total level required for the individual operating utilities.

It is also important to realize that there are other factors that impact reliability and the risk to meeting a 0.1 LOLE. NERC's 2021 Long-Term Reliability Assessment addresses the concern of future retirements of traditional generation resources like coal-fired generation and the need to consider the risk to resource adequacy and energy risks by supporting the addition of variable energy resources, like wind and solar, with flexible resources that include sufficient dispatchable, fuel-assured and weatherized generation.

(https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf)

Reference pages 3 and 4 of Appendix R (Consolidated System Operations) for a discussion of the reserve margin impact from the addition of variable energy resources. Also reference the Portfolio LOLE and Resource Adequacy Validation section beginning on page 62 of Appendix E (Quantitative Analysis). Using Portfolio 3 for illustration purposes, this section shows how the LOLE, loss of load hours ("LOLH") and expected unserved energy ("EUE") reliability metrics increase as firm dispatchable resources are replaced with variable energy and energy limited resources when comparing the 2035 resource portfolio to the 2030 resource portfolio.

As noted on page 65 of Appendix E (Quantitative Analysis), Duke Energy is participating as a project advisor for EPRI's Resource Adequacy for a Decarbonized Future initiative. The purpose of the initiative is to develop new metrics, methods, and models to ensure energy adequacy for the transition to portfolios with significantly higher adoption of variable and energy limited resources and decreasing levels of dispatchable generation. Further study is needed to determine the reserve margin needed to maintain reliability as the resource portfolio transitions to greater levels of renewable resources, and whether additional reliability metrics including LOLH and EUE are needed to ensure resource capacity and energy adequacy.

Response provided by: Glen Snider, Managing Director Carolinas IRP and Analytics

d. R8-61, preliminary plans and filing requirements.

New generating facilities selected in the Carbon Plan must ultimately be sited (requiring a CPCN) as well as interconnected to the Companies' transmission system under the recently approved DISIS cluster study process set forth in the Companies' FERC Large Generator Interconnection Procedures or state generator interconnection procedures, as applicable. Ensuring that the Commission's siting regulations enable efficient siting approval will be important to achieving the Carbon Plan targets on the timeline required by HB 951. As described in the Companies' March 16, 2022 and April 13, 2022 comments in Docket No. E-100, Sub 178, the Companies believe that the CPCN process can and should be streamlined based on the findings made by the Commission in the Carbon Plan process and the PBR process (where applicable)

As noted in the Public Staff's question, the obligation to file preliminary plans 120 days in advance of filing a CPCN application under R8-61(a) applies only to new generating facilities 300 megawatts (alternating current) or more. Duke Energy has not made a determination at this time whether this pre-filing requirement continues to be appropriate or should be modified or eliminated. In addition to evaluating whether this pre-filing requirement should be retained for resources selected in the Carbon Plan, Duke Energy will also evaluate the need for waivers on a case-by-case basis. Carbon Plan-selected resources should also be designated as "ready" resources as they progress through the DISIS study process.

Specific to the Public Staff's inquiry regarding Exhibit 5, Duke Energy identifies that the current applicability of that Exhibit in the CPCN rule for coal or nuclear-fueled generating facilities is consistent with N.C. Gen. Stat. § 62-110.1(e).

Duke Energy looks forward to further engagement with the Public Staff to ensure the CPCN filing requirements in Rule R8-61 do not impede the efficient siting of new resources selected in the Carbon Plan.

Response provided by: Glen Snider, Managing Director Carolinas IRP and Analytics

e. R8-62, CECPCN for transmission.

Consistent with Duke Energy's response to sub-part d. relating to siting of new generating facilities, ensuring that the Commission's transmission siting regulations enable efficient siting approval will be important to achieving the Carbon Plan targets on the timeline required by HB 951.

Duke Energy supports reviewing Rule R8-62 to ensure the CECPCN process facilitates efficient siting approval of new transmission facilities that are necessary to interconnect resources selected in the Carbon Plan. To the extent a solar facility or another resource is selected as needed in the Carbon Plan, this selection provides indicia of the public convenience and necessity required to support construction of any required transmission facilities. Environmental compatibility would also need to be assessed. Importantly, however, the Companies are anticipating that any CECPCN (like the CPCN for the generating facility) would most likely be obtained after a resource is selected for development under the Carbon Plan. Whether future RFPs and PPAs should introduce market uncertainty by including conditional language to address the risk of a CECPCN not being granted, or if the routing materially changes and causes delays or increases in costs will be evaluated, as needed, on a case-by-case basis.

Response provided by: Sammy Roberts, General Manager - Transmission Planning and Operations Strategy

f. R8-63 and R8-64, CPCNs for Merchant Plants or Qualifying Facilities.

Selection of a merchant solar facility or qualifying facility to meet the Carbon Plan objectives should provide strong support that the resource is needed and that its construction is supported by the public convenience and necessity. At this time, the Companies have not identified any Rule changes that are necessary in R8-63 and R8-64 to mitigate the risk of a CPCN being denied after the Solar RFP has concluded, but will further assess this issue in advance of the proposed rule revision to be filed with the Commission in January 2023. The Companies' current form of solar PPAs include covenants that required the project owner-Seller to obtain all permits, which would include a CPCN.

Response provided by: Glen Snider, Managing Director Carolinas IRP and Analytics

Public Staff
Docket No. E-100, Sub 179
2022 Carbon Plan
Public Staff Data Request No. 5
Item No. 5-16
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

What steps has the Company taken to identify and/or reprioritize existing transmission projects (underway and/or in design status) and shift to the likely transmission upgrades stemming from HB 951 compliance?

RESPONSE:

Duke Energy will continue to review transmission reliability/compliance projects and potential Carbon Plan projects to ensure the now-underway and accelerating fleet transition necessary to meet the Carbon Plan targets can be aligned with needed transmission projects to ensure that the adequacy and reliability of the grid is maintained or improved. In some instances, Duke Energy can synergize the plan to implement projects more efficiently (examples – not putting cathodic protection on aging infrastructure due to an expansion plan project rebuilding the line, doing EM relay replacement concurrently with the transmission expansion plan project, and replacing existing line switches concurrently with the transmission expansion plan project). In other instances, when determined necessary, Duke Energy can prioritize Carbon Plan projects over other projects when the projects cannot be synergized with input from the project sponsors. As the project plans mature, Duke Energy will continue to monitor the risk of delaying any projects vs carbon plan projects to ensure the correct priority is being placed on the projects that have conflicts in order to ensure avoidance of any risk to grid reliability.

Responder: Sammy Roberts, General Manager - Transmission Planning and Operations Strategy

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please explain whether Duke considered any transmission cost savings from resources that interconnect close to retiring coal facilities. If not, why not?

RESPONSE:

While the Companies do expect that some new resources "would be brownfield additions at existing power stations that can utilize the Companies' existing transmission, infrastructure, and workforce" (Carbon Plan Chapter 4, page 14), these potential cost savings were not factored into the generic transmission network upgrade costs used in the Carbon Plan analysis as reported in Table E-44 (Carbon Plan Appendix Q, page 38). As stated in the Executive Summary of the Carbon Plan, "consistent with past practice, in most cases, the selection and siting of new resources will occur after completion of the modeling process (with such modeling results, including any modifications ultimately required by the Commission, informing the procurement process). This approach will ensure that the most cost-effective resources are selected for the benefit of customers, taking into account a range of site-specific and other factors that are not practical for inclusion in the modeling process." In summary, potential new resource cost savings and transmission cost savings associated with brownfield development at retiring coal sites were not explicitly quantified. However, the Company recognizes this potential benefit for consumers, and once specific sites for resources are identified in the execution phase, such savings will become more known and quantifiable for inclusion in future Plan updates.

Responder: Glen Allen Snider, Managing Director Carolinas IRP and Analytics

JOINT

OPEN ACCESS TRANSMISSION TARIFF

OF

DUKE ENERGY CAROLINAS, LLC

DUKE ENERGY FLORIDA, LLC

AND

DUKE ENERGY PROGRESS, LLC

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement" or "LGIA") is made and entered into this ____ day of ___________ 20__, by and between _______________________, a _____________________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Interconnection Customer" with a Large Generating Facility), and ____, a ____________________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

[If Interconnection Customer and Transmission Provider are one and the same: **WHEREAS,** Interconnection Customer and Transmission Provider are one and the same, and therefore the provisions set forth in Articles 5.17.4, 11.4.1 and 11.5 of this Agreement shall not apply;]

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, (a) all milestone dates occurring after the effective date of the suspension shall be suspended during the suspension period and (b) Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so. Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs.

In the event that Interconnection Customers suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16 and requests Transmission Provider to recommence the work required under this LGIA on or before the expiration of the three (3) years following the commencement of such suspension, then the Parties

ATTACHMENT N-1

TRANSMISSION PLANNING PROCESS
(Progress Zone and Duke Zone)

1. INTRODUCTION

Duke Energy Carolinas, LLC (Duke) and Duke Energy Progress, LLC (Progress) (sometimes referred to individually as "Company" and collectively "Companies"), entities with transmission facilities located in the states of North Carolina and South Carolina, ensure that their entire Transmission Systems (i.e., both the portions located in North Carolina and the portions located in South Carolina) are planned in accordance with the local transmission planning requirements imposed by Order Nos. 890 and 1000 through the process developed by the North Carolina Transmission Planning Collaborative (NCTPC Process or Local Planning Process). The NCTPC was formed by the following load serving entities (LSEs) in the State of North Carolina: Duke, Progress, ElectriCities of North Carolina (ElectriCities), and the North Carolina Electric Membership Corporation (NCEMC) (collectively, NCTPC Participants or Participants).

The Companies ensure that their Transmission Systems are planned in accordance with the regional planning requirements imposed by Order No. 1000 through participation in the Southeastern Regional Transmission Planning Process (SERTP or SERTP Process).

In addition to engaging in local transmission planning through the NCTPC Process and regional transmission planning through the SERTP Process, the Companies engage in additional coordination activities with transmission providers located inside and outside their region, as discussed in Section 11. Such activities include participation in SERC Reliability Corporation (SERC), which focuses on reliability assessments. The SERTP engages in interregional coordination as described in Attachment N-1 – FRCC, Attachment N-1 – MISO, Attachment N-1 – PJM, Attachment N-1 – SCRTP, and Attachment N-1 – SPP.

Unless noted otherwise, Section references in this Attachment N-1 refer to Sections within this Attachment N-1.

PART I -- LOCAL PLANNING PROCESS

2. NCTPC PROCESS OVERVIEW INCLUDING THE PROCESS FOR CONSULTING WITH TAG PARTICIPANTS

The NCTPC will annually develop a single, coordinated local transmission plan (Local Transmission Plan) that appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources to meet the needs of LSEs as well as Transmission Customers under this Tariff.

2.1 The North Carolina Transmission Planning Collaborative Participation Agreement (Participation Agreement) governs the NCTPC and the NCTPC Process. The Participation Agreement is located on the NCTPC Website

3.3.2.3 PWG meetings are open to the PWG members, the OSC (and their alternates), and, if approved, guests.

3.3.3 TAG

3.3.3.1 TAG meetings are chaired and facilitated by the OSC chair.

3.3.3.2 The TAG generally meets four times a year.

3.3.3.3 Meetings of the TAG generally are open to the public, i.e., TAG participants. When necessary, TAG meetings may be restricted to TAG participants that are qualified to receive Confidential Information.

3.3.3.4 A yearly meeting and activity schedule is proposed, discussed with, and provided to TAG participants annually.

4. DESCRIPTION OF THE LOCAL PLANNING PROCESS

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

In order to ensure comparability, customers taking Network Transmission Service are expected to accurately reflect their demand response resources appropriately in their annual load forecast projections. Customers taking Point-to-Point Transmission Service are expected to accurately reflect their demand response resources in submitting their requests for Transmission Service and in submitting information about potential needs for Point-to-Point Transmission Service. Eligible Customers providing information about potential needs for Point-to-Point Transmission Service are expected to accurately reflect their demand response resources in submitting information. To the extent a TAG participant has a demand response resource or a generation resource that the TAG participant desires the NCTPC to specifically consider as an alternative to transmission expansion, or otherwise in conjunction with the NCTPC Process, such TAG participant sponsoring such demand response resource or generation resource shall provide the necessary information (cost, performance, lead time to install, etc.) in order for the NCTPC to consider such demand response resource or generation resource alternatives comparably with other alternatives.

4.1 Overview of Local Planning Process

The Local Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads. The Local Planning Process includes a base reliability study (base case) that evaluates each Transmission System's ability to meet projected load with a defined set of resources as well as the

6.4.3 Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Companies shall not be within the scope of the dispute resolution process of this Tariff.

7. TRANSMISSION COST ALLOCATION FOR LOCAL PROJECTS

7.1 OATT Cost Allocation

With the exception of "Joint Local Reliability Projects" and "Joint Local Economic Projects" nothing in this Attachment is intended to alter the cost allocation policies of the Tariff.

7.2 Joint Local Reliability Project Cost Allocation

7.2.1 A Joint Local Reliability Project is defined as any reliability project that requires an upgrade to a Company's system that would not have otherwise been made based upon the reliability needs of the Company.

7.2.2 An "avoided cost" cost allocation methodology will apply to reliability projects where there is a demonstration that a Local Project meets the criteria for a Joint Local Reliability Project.

7.2.3 The NCTPC Planning Process results in a set of projects that satisfy the reliability criteria of the Companies who are parties to the Participation Agreement (i.e., Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Company were only considering projects on its system to meet its reliability criteria. A Joint Local Reliability Project must have a cost of at least $1 million to be subject to the avoided-cost cost allocation methodology. The costs of a Joint Local Reliability Project with a cost of less than $1 million would be borne by each Company based on the costs incurred on its system.

7.2.4 Unless a Joint Local Reliability Project is determined by the NCTPC to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Local Transmission Plan. But, if a Joint Local Reliability Project is determined by the NCTPC to be the most cost effective solution, it will have its costs allocated based on an avoided cost approach, whereby each Company looks at the stand-alone approach to maintaining reliable service and shares the savings of not implementing the stand-alone approach on a pro-rata basis. The avoided cost approach formula can be expressed as follow:

(Company $_x$'s Avoided Cost/Total Avoided Cost) * cost of Joint Local Reliability Project = Company $_x$'s Cost Allocation

Oversight/Steering Committee

Scope

Purpose

The Oversight/Steering Committee (OSC) manages the NCTPC Participants' Transmission Planning Process.

The duties of the OSC, for the areas of the State of North Carolina and South Carolina served by the NCTPC Participants, include the following:

a. Participate in the reliability planning process, and oversee the development of the Local Economic Study Process;

b. Review and approve transmission planning criteria and critical assumptions for the bulk transmission system (*i.e.*, 230 kV and above plus lower voltage facilities that substantively affect the reliability planning process and the Local Economic Study Process) and, where appropriate, develop and recommend such criteria and assumptions to be used by the Planning Working Group (PWG);

c. Promote the application of such planning criteria and/or assumptions within the territories served by the NCTPC Participants;

d. Review and recommend revisions to the transfer capability, transmission reserve margin (TRM) and capacity benefit margin (CBM) criteria and calculations of the investor-owned utilities for consistency with SERC and NERC established criteria as well as good utility practice; recommend transfer capability, TRM and CBM criteria or methodologies which would be applied consistently in the Process, adjusted as appropriate, to accommodate local conditions that merit special consideration;

e. Direct the activities of and provide oversight for the PWG;

f. Nominate and approve the PWG members. Duke Energy Carolinas, Duke Energy Progress, ElectriCities and NCEMC shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the membership guidelines described in the PWG Scope Document;

g. Select the Administrator and provide oversight direction of the work of the Administrator;

h. Develop an annual business plan with an associated budget each year and monitor budget versus actual expenditures throughout the year; and

i. Keep the NCUC and non-LSE stakeholders informed concerning the work undertaken by this process;

Subcommittees

The OSC has the authority to form subcommittees as necessary. A scope document for each subcommittee shall be developed and approved by the OSC before the subcommittee begins its work.

The Planning Working Group will be a standing subcommittee that works under the direction of the OSC and will operate within the parameters as identified within its defined scope of work (*e.g.*, its scope document).

Membership

The OSC will consist of eight (8) appointed members plus ex officio members as approved by the OSC. Duke Energy Carolinas, Duke Energy Progress, ElectriCities and NCEMC shall each appoint two (2) members to the OSC and may each appoint up to two (2) alternate members, all of whose qualifications shall be materially consistent with the guidelines for OSC membership set forth in this section. The electric cooperatives and municipalities' industry segments shall establish rules for electing and replacing its representatives to the OSC consistent with the guidelines provided in this section.

1) OSC Membership Guidelines

- a) Possess a broad knowledge of transmission grid planning, system operations and resource planning including the following:
  - i) Understanding of the process for load serving entities to acquire resources and request proposals for capacity and energy
- b) Broad understanding of electric industry and utility issues
- c) Possess a reasonable understanding of NERC and SERC Planning Standards and good utility Practices
- d) Possess a reasonable understanding of FERC regulations and OATT requirements including the following:
  - i) FERC Standards of Conduct and Code of Conduct
  - ii) Processes for Requesting Transmission Service
  - iii) Processes for Requesting Interconnection Service
- e) Possess a reasonable understanding of interregional study processes and results
- f) Possess a reasonable understanding of transfer capability, TRM, CBM principles
- g) Possess a reasonable understanding of the state regulatory process including the following:
  - i) Integrated Resource Plans (IRP) process
  - ii) Transmission siting approval process
- h) Ability to comply with Standards of Conduct requirements stated in the Participation Agreement/no involvement in market activities
- **i)** Authority to speak and vote on their company's behalf

2) Changes in OSC Membership

Changes in the OSC membership may be made by the NCTPC Participant making the change by providing written notification of the change to the OSC Chair. The Participant making the change is responsible for providing a replacement representative from their Participant organization.

Membership Terms

An OSC member and their alternate will serve on the OSC until replaced through either the election or appointment process in place for their representative Participant organization or until the member or alternate resigns.

The OSC members shall periodically evaluate the performance of the Administrator and shall determine if the contract with the Administrator should be renewed or if another Administrator should be selected.

OSC Committee Structure

The OSC shall select a Chair, Vice Chair, and Treasurer from among its members. The term of office for these positions is two years. The officer positions will be rotated among the two participating investor-owned utilities, electric membership cooperatives and municipalities (*e.g.*, officer rotation would occur every two years among the four groups) according to the following schedule: Electricities, Duke Energy Carolinas, NCEMC, Duke Energy Progress. At any one time, each officer position shall be represented by a different Participant organization.

Chair Responsibilities

In addition to the duties, rights, and privileges discussed elsewhere in this document, the OSC chair has the responsibility to:

- Provide general supervision of OSC activities
- Schedule all OSC meetings
- Prepare, distribute and post notices of OSC meetings
- Develop OSC agendas, and rule on any deviation, addition, or deletion from a published agenda
- Preside at OSC meetings
- Manage the progress of all OSC meetings, including the nature and length of discussion, recognition of speakers, motions, and voting
- Act as spokesperson for the OSC
- Report on OSC activities to the NCUC
- Maintain OSC membership records
- Perform other duties as directed by consensus of the OSC members

Vice Chair Responsibilities

The OSC Vice Chair shall act as the OSC Chair if requested by the Chair (for brief periods of time) or if the Chair is absent or unable to perform the duties of the chair. If the Chair is permanently unable to perform his or her duties, the OSC Vice Chair shall act as the Chair until the OSC selects a new Chair.

The Vice-Chair has the responsibility to:

- Assist the OSC Chair
- Perform duties of the OSC Chair when the OSC cannot otherwise support these duties

Treasurer Responsibilities

The Treasurer will be one of the OSC Members. The term of office for the Treasurer position is two years. The OSC is authorized to make changes in the designation of the Treasurer as conditions warrant.

The Treasurer has responsibility to:

- Receive and disburse funds
- Periodically disclose all receipts and disbursements to each NCTPC Participant
- Ensure payment of any charges for outside services performed for the NCTPC, specifically charges for services of the Administrator and NCTPC website maintenance.

Committee Member Responsibilities

OSC members have the responsibility to:

- Represent their Participant organization
- Provide knowledge and expertise representative of their Participant organization
- Provide their Participant organization feedback on OSC activities
- Respond promptly to all OSC requests for reviews, comments, and voting
- Arrange for alternates to attend and vote at OSC meetings in their absence
- Respond promptly to all requests regarding scheduling OSC meetings

Administrator Responsibilities

The Administrator has the following general responsibilities:

- Serve as a facilitator for the group by working to bring consensus within the group
- Provide transmission planning expertise
- Provide an independent third-party view
- Assist the Chair and Vice-Chair in the performance of their duties as requested
- Ensure that OSC meeting minutes are recorded, and distribute meeting minutes, as appropriate
- Maintain a record of all OSC proceedings, including responses, voting records and correspondence
- Manage the timely posting of relevant materials to the NCTPC website and review the website appearance and structure

The Administrator also provides the leadership role in managing the Stakeholder Process, subject to the oversight of the OSC and normal regulatory oversight. In fulfilling these duties the Administrator performs the following duties:

- Develops the mechanisms to solicit and obtain the input of all TAG participants related to the Stakeholder Process, including scheduling, arranging and leading the TAG meetings.
- Takes all reasonable action to ensure that no member or non-member marketing / brokering organizations receive preferential treatment or achieve competitive advantage through access to transmission-related information.
- Ensures that confidentiality of information and Standards of Conduct and Standards of Conduct requirements are being adhered to within the OSC process.
- Assisting the Participants in avoiding participation in, or facilitation of, any discussions concerning prices or terms of specific products and/or services and/or resources made available

to, or offered by, a Participant to the extent reasonably practicable in implementing the Stakeholder Process.

Meeting Procedures

Meetings

Meetings of the OSC shall be open to OSC members and their alternates, the Administrator, representatives from voting and authorized non-voting LSEs, approved guests as discussed below, and members of the PWG. Representatives from non-voting LSEs will be authorized to attend these meetings under the following conditions: the LSE serves load within the boundaries of the NCTPC Participants; the LSE has signed the necessary confidentiality agreements and meets FERC's Code of Conduct requirements; and the LSE has provided appropriate prior notice of its intention of sending a representative(s) to a particular meeting.

Only voting members or their alternates may act on items before the OSC.

In the absence of specific provisions in this scope document, the OSC shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised*.

Quorum

A quorum requires one voting member or their alternate from each of the industry segments represented in this process (*e.g.*, a total of four voting members must be present with one member being from Duke, Progress, ElectriCities, and NCEMC).

Proxy

If an OSC voting member or their alternate is not able to participate in a particular meeting, the OSC voting member or their alternate may assign their vote to another OSC voting member or their alternate. A written notification of this assignment of the voting privileges must either be provided to the OSC Chair before the meeting or the voting member or alternate that has been given the proxy must provide such written confirmation of this assignment at the beginning of the meeting where the assignment would apply.

Voting

Voting requires a quorum and may take place during formal meetings or may take place through electronic means.

The members of the OSC shall use reasonable good faith efforts to reach decisions via consensus. However, in the event that the OSC is unable to reach a decision by consensus then a decision will be reached by majority vote. When voting is conducted, each of the OSC members (or their designated alternatives) except the ex officio members shall have one vote. In the event of a tie vote, the OSC shall retain an independent third party who will provide a recommended decision based on a review of the issue in dispute. The independent third party will be selected by the OSC from a list of potential candidates, which may include the Administrator. The list of potential candidates shall include no less than three qualified individuals or firms that are mutually acceptable to all Participants. However, the investor-owned utilities shall not be bound by decisions of the OSC to the extent the investor-owned utilities reasonably determine such decisions, as related to reliability planning, are inconsistent with good utility practice or SERC and NERC established criteria or least-cost integrated resource planning principles. The investor-owned utilities shall each retain decision making authority for such decisions, related to reliability, consistent with their statutory responsibilities for reliability, subject to normal regulatory oversight.

It is anticipated that all parties will abide by the decisions of the OSC. However, any NCTPC Participant or TAG participant may request that the North Carolina Utilities Commission Public Staff ("Public Staff') render a nonbinding opinion with regard to any disputed decision of the OSC and any decision of the investor-owned utility superseding a decision by the OSC ("Disputed Decision"). Should the parties be unable to resolve the Disputed Decision through such facilitation by the Public Staff, any NCTPC Participant may seek review of the Disputed Decision by any regulatory or judicial body with jurisdiction over the subject matter of the Disputed Decision.

Each individual member’s vote for each action taken shall be included in the minutes of each meeting.

Guests

Guests are permitted to attend OSC meetings with prior approval. If a member of the OSC (or their alternate) would like to invite a guest to a particular OSC meeting, the member/alternate shall submit this request to the Chair of the OSC. The OSC member/alternate shall identify the name and his or her affiliation in the request to the OSC Chair. The OSC Chair may approve the request on their own motion or after consultation with the OSC membership.

North Carolina Transmission Planning Collaborative
Oversight/Steering Committee
Roster
September 19, 2022

Marty Berland, Chair	ElectriCities of NC
Edgar Bell, Vice Chair	Duke Energy Carolina
Bob Beadle, Treasurer	NCEMC
Sammy Roberts	Duke Energy Progress
Bill Quaintance	Duke Energy Progress
Bob Pierce	Duke Energy Carolina
Kevin Josupait	ElectriCities of NC
John Lemire	NCEMC
Rich Wodyka - Secretary	Consultant Administrator
Andy Fusco	ElectriCities of NC - Alternate
James Manning	NCEMC - Alternate

2022 NCTPC Study Scope Document

Purpose of Study

The purpose of this study is to assess the Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") transmission systems' reliability and develop a single collaborative transmission plan for the DEC and DEP transmission systems that ensures reliability of service in accordance with NERC, SERC, DEC, and DEP requirements. In addition, the study will also assess Local Economic Study option scenarios and/or Public Policy Study requests provided by the Transmission Advisory Group ("TAG") and approved for study by the Oversight Steering Committee ("OSC"). The Planning Working Group ("PWG") will perform the technical analysis outlined in this study scope under the guidance and direction of the OSC.

Two Public Policy requests and four Local Economic Study requests were received from TAG stakeholders by the February 4th deadline for the 2022 study year.

The first Public Policy Study request proposed an analysis to evaluate the potential impacts of the development of PJM off-shore wind on the NC transmission system. After review and discussion with the sponsor requesting this study analysis, the request was put on hold.

The second Public Policy Study request proposed an analysis to evaluate 9 GW of solar resources being incorporated into the NC transmission system. After review and discussion with the sponsor requesting this study analysis, the NCTPC and the sponsor agreed to continue discussions to refine the scope of this request. This study analysis is not included in the 2022 scope of work at this time. The study analysis could be initiated later this year as the NCTPC and sponsor continue their discussions to refine the scope of work.[1]

The Local Economic Study requests proposed hypothetical resource transfer analysis in various MW amounts (500MW and 750MW) from DEP and PJM to SCPSA in 2029. To accommodate these Local Economic Study requests, the NCTPC will incorporate these study requests into the resource supply analysis that models hypothetical transfers across the NCTPC interface with

[1] To support the Clean Energy Plan in North Carolina, Duke Energy has proposed 18 proactive projects across DEC and DEP to be considered for approval by the NCTPC. These projects are intended to be a first step to allow for solar expansion in known constrained areas. As we work to further refine the scope of this Public Policy Study request, we will also evaluate the status of the proposed projects and determine how they should be modeled for this study.

neighboring systems. This hypothetical resource supply analysis will evaluate a total of 14 transfers in the NCTPC study year 2032/33 Winter. The specifics of these Local Economic Study requests are identified in the Study Assumptions section below.

The TAG members will have the opportunity to provide input on all the study scope elements of the Reliability Planning Process as the study activities progress. This will include input on the following: study assumptions; study criteria; study methodology; case development and technical analysis; problem identification; assessment and development of solutions (including proposing alternative solutions for evaluation); comparison and selection of the preferred transmission plan; and the transmission plan study results report.

Overview of the Study Process Scope

The scope of the proposed study process will include the following steps:

1. **Study Assumptions**
   - Study assumptions selected.
2. **Study Criteria**
   - Establish the criteria by which the study results will be measured.
3. **Case Development**
   - Develop the models needed to perform the study.
   - Determine the different resource supply scenarios to evaluate.
4. **Methodology**
   - Determine the methodologies that will be used to carry out the study.
5. **Technical Analysis and Study Results**
   - Perform the study analysis and produce the results. Initially, power flow analyses will be performed based on the assumption that thermal limits will be the controlling limit for the reliability plan. Voltage, stability, short circuit and phase angle studies may be performed if circumstances warrant.
6. **Assessment and Problem Identification**
   - Evaluate the results to identify problems/issues.
7. **Solution Development**
   - Identify potential solutions to the problems/issues.

- Test the effectiveness of the potential solutions through additional studies and modify the solutions as necessary such that all reliability criteria are met.
- Perform a financial analysis and rough scheduling estimate for each of the proposed solutions (e.g., cost, cash flow, present value).

8. Selection of a Recommended Collaborative Transmission Plan

- Compare alternatives and select the preferred solution alternatives – balancing cost, benefits and risks.
- Select a preferred set of transmission improvements that provide a reliable transmission system to customers most cost effectively while prudently managing the associated risks.

9. Report on the Study Results

- Prepare a report on the recommended Collaborative Transmission Plan.

Each of these study steps is described in more specific detail below.

Study Assumptions

The specific assumptions selected for the 2022 Study are:

- The years to be studied (study years) will be 2027 Summer and 2027/2028 Winter for a near term reliability analysis and 2032/2033 Winter for a longer-term reliability analysis. Each Load Serving Entity ("LSE") will provide a list of resource supply assumptions and include the resource dispatch order for each of its Designated Network Resources in the DEC and DEP control areas. Generation will be dispatched for each LSE in the cases to meet that LSE's peak load in accordance with the designated dispatch order. LSEs will also include generation down scenarios for their resources, if applicable (e.g., generation outage with description of how generation will be replaced, such as by that LSE's dispatch orders).
- PSS/E and/or TARA will be used for the study.
- Load growth assumptions will be in accordance with each LSE's practice.
- Generation, interchange and other assumptions will be coordinated between Participants as needed.
- The tables below list the major generation facility additions and retirements included in the 2027 Summer, 2027/2028 Winter, and 2032/2033 Winter study models.

Major Generation[2] Facility Additions in 2022 Study Models[3]

Company	Generation Facility	2027S	2027/ 2028W	2032/ 2033W
DEC	Lincoln County CT (525 MW)	Included	Included	Included
DEC	Apex PV (30 MW)	Included	Included	Included
DEC	Aquadale PV (50 MW)	Included	Included	Included
DEC	Bear Branch PV (35 MW)	Included	Included	Included
DEC	Beaverdam PV (42 MW)	Included	Included	Included
DEC	Blackburn PV (61.7 MW)	Included	Included	Included
DEC	Broad River PV (50 MW)	Included	Included	Included
DEC	Brookcliff PV (50 MW)	Included	Included	Included
DEC	High Shoals PV (16 MW)	Included	Included	Included
DEC	Hornet PV (75 MW)	Included	Included	Included
DEC	Lick Creek PV (50 MW)	Included	Included	Included
DEC	Misenheimer PV (74.4 MW)	Included	Included	Included
DEC	Oakboro PV (40 MW)	Included	Included	Included
DEC	Olin Creek PV (35 MW)	Included	Included	Included
DEC	Partin PV (50 MW)	Included	Included	Included
DEC	Pelham PV (32 MW)	Included	Included	Included
DEC	Pinson PV (20 MW)	Included	Included	Included
DEC	Quail PV (30 MW)	Included	Included	Included
DEC	Speedway PV (22.6 MW)	Included	Included	Included

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

[3] As we work to further refine the scope of this study, we will evaluate the status of these proposed new generation sites and retirements, and determine how they should be modeled for this study.

Company	Generation Facility	2027S	2027/ 2028W	2032/ 2033W
DEC	Stanly PV (50 MW)	Included	Included	Included
DEC	Stony Knoll PV (22.6 MW)	Included	Included	Included
DEC	Sugar PV (60 MW)	Included	Included	Included
DEC	Two Hearted PV (22 MW)	Included	Included	Included
DEC	West River PV (40 MW)	Included	Included	Included
DEC	Westminster PV (75 MW)	Included	Included	Included
DEC	Healing Springs PV (55 MW)	Included	Included	Included
DEP	Cabin Creek Solar (70.2 MW)	Included	Included	Included
DEP	Gold Valley Solar (78.8 MW)	Included	Included	Included
DEP	Nutbush Solar (35.0 MW)	Included	Included	Included
DEP	Camp Lejeune Battery (11.0 MW)	Included	Included	Included
DEP	Sapony Creek (23.4 MW)	Included	Included	Included
DEP	Loftins Crossroads (75.0 MW)	Included	Included	Included
DEP	Roxboro CC Units 1-2 (2700 MW)	Not Included	Not Included	Included

Major Generation[4] Facility Retirements in 2022 Study Models[5]

Company	Generation Facility	2027S	2027/ 2028W	2032/ 2033W
DEC	Allen 1-5 (1083 MW)	Retired	Retired	Retired
DEC	Cliffside 5 (574 MW)	Retired	Retired	Retired
DEC	Lee 3 (120 MW)	Retired	Retired	Retired
DEP	Darlington Co 1,2,3,4,6,7,8,10 (514 MW)	Retired	Retired	Retired
DEP	Blewett CTs 1-4 and Weatherspoon CTs 1-4 (232 MW)	Retired	Retired	Retired
DEP	Roxboro Units 1-4 (2462 MW)	Not Retired	Not Retired	Retired
DEP	Mayo Unit 1 (746 MW)	Not Retired	Not Retired	Retired

- 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 2022, the PWG will analyze, among its resource supply options, cases that examine the impacts of fourteen different hypothetical transfers into and out of the DEC and DEP systems. These fourteen hypothetical transfer scenarios are identified in the table below:

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

[5] As we work to further refine the scope of this study, we will evaluate the status of these proposed new generation sites and retirements, and determine how they should be modeled for this study.

Resource Supply Options
2032/33 Winter Hypothetical Transfer Scenarios

ID	Resource From	Sink	Test Level (MW)
1	PJM	DUK[1]	1,000
2	SOCO	DUK	1,000
3	CPLE[2]	DUK	1,000
4	TVA[3]	DUK	1,000
5	PJM	CPLE	1,000
6	DUK	CPLE	1,000
7	DUK	SOCO	1,000
8	PJM	DUK / CPLE	1,000 / 1,000
9	DUK / CPLE	PJM	1,000 / 1,000
10	CPLE	PJM	1,000
11	DUK	PJM	1,000
12	DUK[4]	TVA	1,000
13	DUK	SCPSA	750
14	PJM[5]	SCPSA	500

[1] DUK is the Balancing Authority Area for DEC

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

[3] This hypothetical transfer is intended to evaluate the impact of a 1,000 MW TVA transaction through the SOCO transmission system into DUK.

[4] This hypothetical transfer is intended to evaluate the impact of a 1,000 MW DUK transaction through the SOCO transmission system into TVA.

[5] This hypothetical transfer is intended to evaluate the impact of a 500 MW PJM transaction through the DUK transmission system into SCPSA.

- The PWG will analyze these hypothetical resource options to determine if any reliability criteria violations are created. Based on this analysis, the PWG will provide feedback to the Participants on the viability of these options for meeting future load requirements. The results of this analysis will be included in the 2022 Collaborative Transmission Plan Report.

Study Criteria

The study criteria used will promote consistency in the planning criteria used across the systems of the Participants, while recognizing differences between individual systems. The study criteria will include the following reliability elements:

- NERC Reliability Standards
- SERC requirements
- Individual company criteria (voltage, thermal, stability, short circuit and phase angle)

Case Development

- The most current MMWG system models will be used for the systems external to DEC and DEP as a starting point for the Base Case.
- The Base Case will include the detailed internal models for DEC and DEP and will include current transmission additions planned to be in-service for the given year (i.e. in-service by summer 2027 for 2027S cases and in-service by the winter for 2027/2028W cases as well as in-service by the winter of 2032 for 2032/2033W cases).
- An "All Firm Transmission" Case(s) will be developed which will include all confirmed long term firm transmission reservations with roll-over rights applicable to the study year(s).
- DEC and DEP will each create their respective generation down cases from the common Base Case and share the relevant cases with each other.
- Additional 2032/33 winter cases will be developed to evaluate the resource supply scenarios of the fifteen hypothetical transfers identified under the Study Assumptions section.

Study Methodology

DEC and DEP will exchange contingency and monitored element files so that each can test the impact of the other company's contingencies on its transmission system. Initially, power flow analyses will be performed based on the assumption that thermal limits will be the controlling limit for the reliability plan. Voltage, stability, short circuit and phase angle studies may be performed if circumstances warrant.

Technical Analysis and Study Results

The technical analysis will be performed in accordance with the study methodology. Results from the technical analysis will be reported throughout the study area to identify transmission elements approaching their limits such that all Participants are aware of potential issues and appropriate steps can be identified to correct these issues, including the potential of identifying previously undetected problems.

DEC and DEP will report results throughout the study area based on:

- Thermal loadings greater than 90%.
- Voltages less than 100% for 500 kV and less than 95% for 230 kV, 161 kV, 115 kV, and 100 kV buses; pre- to post-contingency voltage drops of 5% or more.

Assessment and Problem Identification

- Each utility will utilize its own reliability criteria for its own transmission facilities. Each utility will document the reliability problems resulting from its assessments. These results will be reviewed and discussed with the TAG for feedback.

Solution Development

- The PWG will develop potential solution alternatives to the identified reliability problems.
- The TAG will have the opportunity to propose solution alternatives to the identified reliability problems.
- DEC and DEP will test the effectiveness of the potential solution alternatives using the same cases, methodologies, assumptions and criteria described above.
- DEC and DEP will develop rough, planning-level cost estimates and construction schedules for the solution alternatives.

Selection of a Recommended Collaborative Transmission Plan

- The PWG will compare alternatives and select the preferred solution alternatives, balancing costs, benefits and risks.
- The PWG will select a preferred set of transmission improvements that provides 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 PWG will be reviewed and discussed with the TAG for feedback.

Report on the Study Results

The PWG will compile all the study results and prepare a recommended collaborative plan for OSC review and approval. Prior to the OSC's final review and approval, the final draft of the study report will be reviewed and discussed with the TAG members to solicit their input on the recommended collaborative plan. The final report will include a comprehensive summary of all the study activities as well as the recommended transmission improvements including estimates of costs and construction schedules.

I/A

PSDR24 - 2 Updated and Confirmed Mapping of GIR Studies to RZEP Projects - DEC

Mapping of Queue Request Studies to Proactive Projects

Study Hits	Project #	Owner	Project	Project Description	Total Cost (FB, w/ contingency)	Estimate Class	Hartwell	Dogwood	Palmetto Vines	Trinity	Buffalo	Little River	Clinton	Mistflower	Piedmont	Joanna Black	Joanna White	Riley Farms	Sweetwater	Dutchman Creek	Hodges (DESS)	Ten Governors	Sharon	Yellow 1 - Bradley	Fairforest
							See note 1						See note 1				See note 1		See note 1						See note 3
							FeaS OASIS	Grouping	Grouping	Grouping	Grouping	Grouping	SIS OASIS Grouping	Grouping	Grouping	FeaS OASIS Grouping	FeaS OASIS Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	Grouping
						Solar MW Studied	50	52.1	79.8	71.4	74	25.7	20	55	55	37.5	37.5	74.25	34	58	74.9	28	30	35	74.9
							180620_0932	2018-08-15 16:51:43 2018-08-21 14:44:55 180507_1027	2018-08-16 17:41:20 2018-10-09 3:26:00 180420_1055	2018-10-09 3:05:00	2018-10-09 3:35:00	2018-11-28 16:54:00	181220_1159	2019-02-21 12:00:00	2019-03-29 11:59:00	2020-03-06 10:21:00	2020-03-06 10:27:00	2020-03-09 10:14:00	2020-03-09 22:01:00	2020-03-09 22:05:00	2020-03-09 22:06:00 2020-03-09 22:17:00	2020-03-09 22:07:00	2020-03-09 22:10:00 2020-03-09 22:18:00	2020-03-09 22:11:00	2020-03-09 22:12:00
32	1	DEC	Lee 100 kV (Lee-Shady Grove)	Upgrade	$45,000,000	5	X	X	X	X		X	X	X	X	X	X	X	X		X	X	X	X	
31	2	DEC	Piedmont 100 kV (Lee-Shady Grove)	Upgrade	$45,000,000	5	X	X	X	X		X	X	X	X	X	X	X	X		X	X	X	X	
33	3	DEC	Newberry 115 kV (Bush River-DESC)	Upgrade	$42,000,000	5		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
7	4	DEC	Clinton 100 kV (Bush River-Laurens)	Upgrade	$109,000,000	5								X		X	X								
		Total			$241,000,000																				

The updated spreadsheet reflects the review for confirmation of study hits from historical queued generator interconnection request studies showing loading impacts on the RZEP projects.

Legend:

Blue – original spreadsheet showed study hits for these queued requests for the associated RZEP project primarily because of interdependency with Q380 (Friesian upgrades). Subsequent review of study results reflect that not all of the Q380 lines were impacted by the queued requests showing interdependency with Q380. Two other group studies of queued requests (Q454-Q468 and Q487-Q506) were found to not be interdependent on two individual (non-Friesian upgrade) RZEP projects, Camden – Camden Dupont 115 and Robinson – Rockingham 230, respectively.

Orange – Additional queued requests study hits identified in the preparation of responses to PSDR24 Items 1 and 2 for DFAX >3%.

Yellow – Additional queued requests study hits identified in the preparation of responses to PSDR24 Items 1 and 2 **for DFAX >1% but <3%.**

PSDR24 - 2 Updated and Confirmed Mapping of GIR Studies to RZEP Projects - DEC

Mapping of Queue Request Studies to Proactive Projects

Study Hits	Project #	Owner	Project	Project Description	Total Cost (FB, w/ contingency)	Estimate Class
32	1	DEC	Lee 100 kV (Lee-Shady Grove)	Upgrade	$45,000,000	5
31	2	DEC	Piedmont 100 kV (Lee-Shady Grove)	Upgrade	$45,000,000	5
33	3	DEC	Newberry 115 kV (Bush River-DESC)	Upgrade	$42,000,000	5
7	4	DEC	Clinton 100 kV (Bush River-Laurens)	Upgrade	$109,000,000	5
		Total			$241,000,000	

Project #	Ursa	Yorkshire 2	Corbets	Angus B / Angus W	Mobjack	Five Circle	Newberry (DEC)	Newberry (Adger/Hudson)	Hodges (Birdseye)	Yorkshire	Newberry 402	Newberry (JSD)	Abbeville (JSD)	Stoney Point	McCormick	Bailybead	Newberry (E)	Bradley-SC	
				See note 2													See note 1		See note 4
	Grouping	Grouping	FeaS OASIS		FeaS OASIS	SIS State Grouping	SIS OASIS	SIS State	FeaS OASIS	SIS OASIS Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	Grouping	TCSP1 OASIS
Solar MW Studied	35.5	40	74.9	72	74.9	71.5	44.4	71.8	40	38.5	25	25	25	23	75	32	74.5	75	474.85
	2020-03-09 22:16:00 2020-03-09 22:19:00	2020-03-09 22:21:00	180214_1604	42544-01 42544-02	171031_1350	SC2017-01116	42858-01 2018-10-09 03:06:00	CHKLIST-11704	2020-03-06 10:03:00	42951-01	'2018-08-15 16:16:15	'2019-12-10 16:13:00	'2019-12-10 11:14:00	'2018-05-18 09:27:21	2020-03-09 22:08:00	171115_1436	SC2017-01143	170914_1054	DEC Trans Cluster
1	X	X	X		X	X	X		X	X	X	X	X	X	X	X	X	X	
2	X	X	X		X	X			X	X	X	X	X	X	X	X	X	X	
3	X	X	X		X	X	X		X	X	X	X	X	X		X	X	X	
4			X		X			X											X

The updated spreadsheet reflects the review for confirmation of study hits from historical queued generator interconnection request studies showing loading impacts on the RZEP projects.

Legend:

Blue – original spreadsheet showed study hits for these queued requests for the associated RZEP project primarily because of interdependency with Q380 (Friesian upgrades). Subsequent review of study results reflect that not all of the Q380 lines were impacted by the queued requests showing interdependency with Q380. Two other group studies of queued requests (Q454-Q468 and Q487-Q506) were found to not be interdependent on two individual (non-Friesian upgrade) RZEP projects, Camden – Camden Dupont 115 and Robinson – Rockingham 230, respectively.

Orange – Additional queued requests study hits identified in the preparation of responses to PSDR24 Items 1 and 2 for DFAX >3%.

Yellow – Additional queued requests study hits identified in the preparation of responses to PSDR24 Items 1 and 2 **for DFAX >1% but <3%.**

Mapping of Queue Request Studies to Proactive Projects

PSDR24 - 1 - 2 Mapping of Interconneciton Studies to RZEP Projects - DEP

						Solar MW Studied	75	70.2	80
							Q380/ Q529	Q381	Q383
Study Hits	**Project #**	**Owner**	**Project**	**Project Description**	**Total Cost (FB, w/ contingency)**	**Estimate Class**	Report PDF	Report PDF	Report PDF
32	5	DEP	Cape Fear Plant – West End 230kV Line	Rebuild	$70,349,010	4	X	X	X
38	6	DEP	Erwin – Fayetteville East 230kV Line	Rebuild	$83,933,750	4	X		X
11	7	DEP	Erwin – Fayetteville 115kV Line	Rebuild	$21,288,975	4	X		X
23	8	DEP	Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	Rebuild	$14,106,625	4	X		
23	8.5	DEP	Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	Rebuild	$11,600,000	5	X		
14	9	DEP	Rockingham – West End 230kV West Line	Upgrade	$1,457,875	4	X	X	
7	10	DEP	Milburnie 230kV Substation	Add bus prote	$4,324,127	4			
1	11	DEP	Erwin-Milburnie 230kV Line	Rebuild	$5,300,000	5			
3	12	DEP	Sutton Plant-Wallace 230kV Line	Upgrade	$500,000	5			
15	13	DEP	Weatherspoon-Marion 115kV Line	Rebuild	$13,000,000	5			
12	14	DEP	Camden-Camden Dupont 115kV Line	Rebuild	$2,600,000	5			
20	15	DEP	Camden Junction-DPC Wateree 115kV Line	Rebuild	$10,000,000	5			
21	16	DEP	Robinson Plant-Rockingham 115kV Line	Rebuild	$38,000,000	5			
20	17	DEP	Robinson Plant-Rockingham 230kV Line	Rebuild	$43,100,000	5			
			Total		**$319,560,362**				

Solar MW Studied	100	30	70.1	71.5	60.5	60.5	80	80	20	20
	Q385	Q386	Q387	Q404	Q405	Q406	Q407	Q408	Q412	Q367/ Q413
Project	Report PDF	Report PDF	Report PDF	Group Study	Group Study	Group Study	Group Study	Report PDF	Group Study	Group Study
Cape Fear Plant – West End 230kV Line	X			X	X	X	X		X	X
Erwin – Fayetteville East 230kV Line	X	X	X	X	X	X	X		X	X
Erwin – Fayetteville 115kV Line	X				X		X			
Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	X		X		X	X	X		X	
Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	X		X		X	X	X		X	
Rockingham – West End 230kV West Line				X			X		X	X
Milburnie 230kV Substation								X		
Erwin-Milburnie 230kV Line					X					
Sutton Plant-Wallace 230kV Line			X							
Weatherspoon-Marion 115kV Line					X	X			X	
Camden-Camden Dupont 115kV Line						X				
Camden Junction-DPC Wateree 115kV Line				X	X	X			X	X
Robinson Plant-Rockingham 115kV Line					X	X			X	X
Robinson Plant-Rockingham 230kV Line				X	X	X			X	X
Total										

Project	Q419 Group Study	Q425/ Q528 Report PDF	Q426 Group Study	Q429 Group Study	Q430 Group Study	Q431 Report PDF	Q432 Report PDF	Q433 Group Study	Q434 Group Study	Q435 Group Study	Q436 Group Study
Solar MW Studied	100	165	74.5	72.54	77.53	60	75	60	63	75	63
Cape Fear Plant – West End 230kV Line		X	X	X	X	X	X		X	X	X
Erwin – Fayetteville East 230kV Line	X	X	X	X	X	X	X	X	X	X	X
Erwin – Fayetteville 115kV Line					X	X					
Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section					X	X	X		X	X	X
Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section					X	X	X		X	X	X
Rockingham – West End 230kV West Line			X	X					X		X
Milburnie 230kV Substation											
Erwin-Milburnie 230kV Line											
Sutton Plant-Wallace 230kV Line											
Weatherspoon-Marion 115kV Line							X		X	X	X
Camden-Camden Dupont 115kV Line							X		X	X	
Camden Junction-DPC Wateree 115kV Line			X	X			X		X	X	X
Robinson Plant-Rockingham 115kV Line	X	X	X				X		X	X	X
Robinson Plant-Rockingham 230kV Line			X	X			X		X	X	X
Total											

Solar MW Studied	80	69.5	72	75	60	80	80	75	80	80	80
Project	Q437 Group Study	Q438 Group Study	Q439 Group Study	Q444/ Q466 Group Study	Q445 Group Study	Q447/ Q463/ Q464 Group Study	Q448 Report PDF	Q449 Group Study	Q450 Report PDF	Q451 Group Study	Q454/ Q468 Group Study
Cape Fear Plant – West End 230kV Line	X	X		X	X		X				X
Erwin – Fayetteville East 230kV Line	X	X	X	X	X		X	X			X
Erwin – Fayetteville 115kV Line											
Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	X	X	X	X	X						X
Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	X	X	X	X	X						X
Rockingham – West End 230kV West Line		X			X						
Milburnie 230kV Substation						X		X	X	X	
Erwin-Milburnie 230kV Line											
Sutton Plant-Wallace 230kV Line											
Weatherspoon-Marion 115kV Line	X	X		X	X						
Camden-Camden Dupont 115kV Line		X		X	X			X			X
Camden Junction-DPC Wateree 115kV Line	X	X		X	X			X			X
Robinson Plant-Rockingham 115kV Line	X	X		X	X						X
Robinson Plant-Rockingham 230kV Line	X	X		X	X						X
Total											

Solar MW Studied	74.9	80	74.9	80	80	Battery	74.9	450	80	2036
	Q457	Q465/ Q467	Q469	Q471	Q478	Q479	Q486/ Q497	Q499	Q487/ Q506	DEP Trans Cluster
Project	Report PDF	Group Study	Group Study	Report PDF	Group Study	Report PDF	Group Study	Report PDF	Group Study	Report PDF
Cape Fear Plant – West End 230kV Line	X		X	X		X	X		X	X
Erwin – Fayetteville East 230kV Line	X		X	X		X	X	X	X	X
Erwin – Fayetteville 115kV Line			X			X		X		X
Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	X		X						X	X
Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	X		X						X	X
Rockingham – West End 230kV West Line									X	X
Milburnie 230kV Substation		X			X					
Erwin-Milburnie 230kV Line										
Sutton Plant-Wallace 230kV Line									X	X
Weatherspoon-Marion 115kV Line	X						X		X	X
Camden-Camden Dupont 115kV Line	X			X			X			
Camden Junction-DPC Wateree 115kV Line	X			X			X			
Robinson Plant-Rockingham 115kV Line	X			X			X		X	X
Robinson Plant-Rockingham 230kV Line	X			X		X	X			
Total										

TRANSMISSION PANEL EXHIBIT 3: DEC TRANSMISSION PLANNING SUPPLEMENTAL STUDY OF PROSPECTIVE SOLAR ADDITIONS FOR CAROLINAS CARBON PLAN

I. Supplemental Study Purpose

The purpose of this study was to further analyze the need for proactive transmission upgrades to help Duke Energy meet Carbon Plan and Integrated Resource Plan goals in the Carolinas. Prior studies in the serial generator interconnection process and the Transitional Cluster Study have demonstrated the need for transmission upgrades that mitigate common constraints but cannot be financed by solar generation developers. In this study, prior solar generation interconnection requests that withdrew from the queue were studied with the latest Duke Energy transmission power flow models. Cluster study methods were used to determine overloaded transmission facilities, appropriate upgrades, and contributions to the overloads by the studied solar generators.

II. Supplemental Study Assumptions and Limitations

This study started with a summer peak base case representing Transitional Cluster Study Phase 2. In DEC, only 8 requests from Transitional Cluster Study Phase 1 proceeded to Phase 2. These 8 Phase 2 generators, as well as prior generators still in the interconnection processes, were added to the most recent internal transmission planning model.

This study, along with the one performed by DEP, included 5400 MW of additional solar generation across DEC and DEP, with a split of 1900 MW studied in DEC and 3500 MW studied in DEP. DEC and DEP studies were performed independently, similar to the cluster study process, and evaluated the need for upgrades in the respective area studied. For each utility, the most recent withdrawn transmission solar requests were selected for inclusion, going back in time until the desired total solar MW addition was reached, with the following caveats:

- Large solar plants greater than 175 MW were not included due to the high likelihood of large local upgrades to connect them to the grid;
- Some prior requests were duplicates at the same site with different assumptions but using the same solar field. In these situations, only one request was included, and duplicates were removed;
- In DEC, only one request was considered per 44 kV line due to the significant local impact of more than one request on a 44 kV line;
- Only standard solar generation output was assumed, with storage at solar sites not considered. Thus only summer cases were studied and winter cases were not studied; and
- All geographical locations in DEC were considered, both inside and outside the current Red Zones.

Based on these parameters, 41 transmission solar projects (1937 MW) were added to the DEC Transitional Cluster Phase 2 models. See the complete list on page 5 below.

It is difficult to predict future locations for solar additions, especially considering the large quantity of solar generation needed to meet Carbon Plan goals. Due to the large amount of land needed per MW of solar capacity, solar plants typically have much smaller MW sizes than conventional generation plants such as combined cycle generation. Meeting Carbon Plan goals will require dozens or more individual solar generation plants spread across the DEC and DEP systems, with concentrations expected in the NC and SC Red Zones as represented by prior solar generation requests.

This study used prior withdrawn requests as the best available data for selection of future solar locations and MW sizes. These sites were previously submitted to DEC as official interconnection requests in the FERC or state interconnection processes, indicating that there was land available at those locations at the time, along with willing landowners and other attractive local conditions. Selecting the most recent prior withdrawn requests reduces the likelihood that local conditions have changed and reduced the viability of solar generation at these sites.

While the DEC and DEP Red Zones are of particular interest in these studies, all geographic regions were considered to avoid biasing the results towards the Red Zone Expansion Plan (RZEP) transmission upgrades. Note that while the fewer number of Red Zone requests in recent years may be due to the well-known congestion and upgrade costs in the Red Zones, elimination of Red Zone congestion with pro-active upgrades may incentivize a higher concentration of Red Zone requests than seen in recent years.

DISIS 2022 requests were not considered in this study, although there could be requests in DISIS 2022 that are the same as or similar to prior requests modeled in this study.

III. Summary of Results

The results of the DEC study are summarized below, with additional details provided in the following tables.

- This analysis provides support for the (4) identified RZEP projects in DEC. See Table A below.
- The analysis shows the need for additional upgrades to reliably interconnect the 1937 MW of added solar generation. See Table B below.
- The scope of the transmission solutions vary from facility to facility (e.g. replacement of ancillary pieces of equipment versus rebuild of a transmission line).
- Some transmission solutions may mitigate more than one identified issue.
- 44 kV issues are typically associated with too much solar on the 44 kV transmission system (including behind deliveries) and may be mitigated by limiting size/aggregation of generators (transmission, distribution) on the 44 kV.

Table A: RZEP Upgrades Identified in DEC Supplemental Study and Recommended for Immediate Implementation

TRANSMISSION FACILITY	UPGRADE
Clinton BL/WH 100 kV Line	Upgrade 29.3 miles of 100 kV between Bush River Tie and Laurens Tie
Lee BL/WH 100 kV Line	Upgrade 11.9 miles of 100 kV between Lee Steam Station and Shady Grove Tie.
Newberry BL/WH 115 kV Line	Upgrade 11.3 miles of 115 kV between Bush River Tie and DESC change-of-ownership.
Piedmont BL/WH 100 kV Line	Upgrade 12.7 miles of 100 kV between Lee Steam Station and Shady Grove Tie.

Table B: Other Upgrades Identified

TRANSMISSION FACILITY	UPGRADE
Belfast 44 kV Line	Upgrade 7.4 miles of 44 kV between ID: 126068 and Laurens EC Del 16. Upgrade ancillary equipment on 44 kV between Laurens EC Del 16 and Joanna Switching Station.
Bond BL / WH 100 kV Lines	Upgrade 1 mile of 100 kV between Clark Hill Tie and Greenwood Tie.
Broadway BL/WH 100 kV Lines	Upgrade 6.5 miles of 100 kV between Belton Tie and WS Lee Combined Cycle.
Bush River Tie 230/100/44 kV Transformer	Install 100/44 kV transformer at Bush River Tie.
Bush River Tie 07 115/100 kV Transformer	Upgrade bank 7 (115/100 kV) at Bush River Tie and remove DESC-owned bank 8 (115/100 kV) at Bush River Tie.[1]
Champion BL/WH 100 kV Lines	Upgrade 4.1 miles of 100 kV between ID: 005515 and Bush River Tie.
Chappells 44 kV Line	Upgrade ancillary equipment on 44 kV between Bush River Tie and Buzzard Roost Switching Station.
Clark Hill 115 kV Line, Clark Hill 115/100 kV Transformer	Rebuild 6.2 miles of 115 kV (from Clark Hill Tie end) as double circuit (network 115 kV on one side, radial 100 kV on the other side) and interconnect the solar to the new, radial 100 kV line. This solution mitigates the need to rebuild 30+ miles of the Clark Hill 115 kV line and to increase 115/100 kV transformation at Clark Hill.

[1] Analysis of affected systems were beyond scope of the study; however, the Companies did identify impacted tie lines, which can be partially or fully owned by neighboring utilities.

TRANSMISSION FACILITY	UPGRADE
Clark Hill Tie 01 100/44 kV Transformer	Upgrade 100/44 kV transformer at Clark Hill Tie.
Copeland 44 kV Line	Upgrade 5.3 miles of 44 kV between Clinton Tie and Joanna Switching Station.
Cypress Tie 03 100/44 kV Transformer	Modify Cypress Tie.
Dan River BL/WH 100 kV Line	Upgrade 8.1 miles of 100 kV between ID: 015546 and Lake Townsend Retail Tap / Rudd Retail Tap.
Florida 44 kV Line	Upgrade 1.1 miles of 44 kV between Bradley Retail Tap and Clark Hill Tie.
Jordan 100 kV Line	Upgrade and rebuild 5.1 miles of single circuit 100 kV as double circuit 100 kV. This solution mitigates loading issues on the Jordan 100 kV line and mitigates the need to also upgrade 3.8 miles of 100 kV between Lockhart Power Del 3 and Morris Switching Station.
Kennedy BL/WH 100 kV Line	Upgrade ancillary equipment on 100 kV between DUK Customer and Newton Tie.
Landsford WH 100 kV Line	Upgrade ancillary equipment on 100 kV between Bowater Switching Station and Great Falls Switching Station.
Monroe WH 100 kV Line	Contingent Facility – upgrade expected to be completed in 26/27
Mull BL/WH 100 kV Line	Upgrade 9.1 miles of 100 kV between Lincolnton Tie and Orchard Tie.
Oakvale BL/WH 100 kV Line	Upgrade ancillary equipment (including breakers) on 100 kV between Oakvale Tie and Shady Grove Tie.
Pine Hall BL/WH 100 kV Line	Upgrade 2.8 miles of 100 kV between ID: 126042 and Walnut Cove Tie. Upgrade ancillary equipment between DUK Customer and Madison Tie.
Sevier BL/WH 100 kV Line	Upgrade 1.6 miles of 100 kV.
Thicketty 44 kV Line	Upgrade 0.4 miles of 44 kV between ID: 126064 and Broad River EC Del 8.
Vashti 44 kV Line	Upgrade 1.3 miles of 44 kV between ID: 126046 and DUK Customer tap.
Westbrook 44 kV Line	Upgrade ancillary equipment on 44 kV between ID: 126028 and Cypress Tie.

IV. Detailed Data and Results

The following table lists the generators included in DEC Supplemental Study. Detailed results of the study are provided at Section 1.0 below. Section 2.0 provides details of the contingent facility identified in the Study.

ID	MW (Summer Peak)	Point of Interconnection
017801	71.4	Cypress WH 100 KV
055960	25	Lattimer 44 KV
062756	32	Wilson Creek 44 KV
174146	31	Monroe WH 100 KV
023506	74	Jordan 100 KV
120022	25	Fingerville 44 KV
126022	47	Pines WH 100 KV
022154	65	Landsford WH 100 KV
126036	58	Jordan 100 KV
126038	74.9	Jordan 100 KV
015546	45	Dan River WH 100 KV
126042	80	Pine Hall WH 100 KV
126046	24	Vashti 44 KV
069510	40	Greenwood WH 100 KV
126026	74.9	Hodges BL 100 KV
015376	15	Chester BL 100 KV
165980	37.5	Clinton BL 100 KV
123318	80	Mocksville WH 100 KV
063666	55	Clinton WH
026749	44.4	Champion WH 100 KV
056654	25	Kinards 44 KV
142880	80	Bannertown WH 100 KV
062472	55	Clark Hill 115 KV
022466	22.5	Terrell 44 KV
068440	74.25	Clark Hill 115 KV
171806	21	Ronda 44 KV
023290	30	Collins WH 100 KV
126028	30	Westbrook 44 KV
039390	80	Mull BL 100 KV
126064	30	Thicketty 44 KV
126040	50	Mayo BL 100 KV
126068	28	Belfast 44 KV
023270	22.6	Tirzah 44 KV
005515	71.4	Champion BL 100 KV
015543	58	Monroe WH 100 KV
126032	35.5	Champion WH 100 KV
126070	75	Yadkin BL 100 KV
126074	60	Elon WH

ID	MW (Summer Peak)	Point of Interconnection
126072	15	Elon WH
126076	35	Florida 44 KV
126078	40	Clinton BL 100 KV

1.0 RZEP Projects – Detailed DEC Supplemental Study Results

1.1 Upgrade Clinton B/W 100 kV Lines (Bush River Tie-Laurens Tie)

1.1.1 Upgrade Bush River Tie- ID: 164382

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
063666	55	99.879	84.513	54.933	100	TBD[2]
				54.933	100	TBD

1.1.2 Upgrade ID: 164382-Clinton Tie

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
062756	32	3.328	1.638	1.065	1.805	TBD
023506	74	2.756	3.138	2.039	3.457	TBD
126036	58	2.756	2.459	1.598	2.710	TBD
126038	74.9	2.756	3.176	2.064	3.499	TBD
165980	37.5	56.851	32.799	21.319	36.140	TBD
026749	44.4	7.745	5.290	3.439	5.829	TBD
062472	55	2.443	2.067	1.344	2.278	TBD
068440	74.25	2.172	2.481	1.613	2.734	TBD
005515	71.4	7.459	8.193	5.326	9.028	TBD
126032	35.5	8.226	4.493	2.920	4.950	TBD
126076	35	2.524	1.359	0.883	1.498	TBD
126078	40	38.448	23.660	15.379	26.071	TBD
				58.990	100	TBD

[2] DEC can only provide the aggregate cost estimate for upgrading the entire (breaker to breaker) Clinton 100 kV lines at this time; that aggregate cost estimate is $109 million.

1.1.3 Upgrade Clinton Tie-ID: 063666

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
062756	32	3.477	1.613	1.113	1.735	TBD
023506	74	2.857	3.064	2.114	3.297	TBD
126036	58	2.857	2.402	1.657	2.584	TBD
126038	74.9	2.857	3.101	2.140	3.337	TBD
165980	37.5	52.848	28.722	19.818	30.909	TBD
026749	44.4	8.243	5.304	3.660	5.708	TBD
056654	25	12.128	4.394	3.032	4.729	TBD
062472	55	2.52	2.009	1.386	2.162	TBD
068440	74.25	2.224	2.393	1.651	2.575	TBD
126068	28	12.107	4.913	3.390	5.287	TBD
005515	71.4	7.935	8.211	5.666	8.836	TBD
126032	35.5	8.763	4.509	3.111	4.852	TBD
126076	35	2.608	1.323	0.913	1.424	TBD
126078	40	36.17	20.968	14.468	22.565	TBD
				64.118	100	TBD

1.1.4 Upgrade ID: 063666-Laurens EC Del 40

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
062756	32	2.958	1.502	0.947	1.519	TBD
023506	74	2.437	2.863	1.803	2.895	TBD
126036	58	2.437	2.244	1.413	2.269	TBD
126038	74.9	2.437	2.897	1.825	2.930	TBD
063666	55	77.094	67.304	42.402	68.065	TBD
026749	44.4	6.978	4.918	3.098	4.973	TBD
062472	55	2.152	1.879	1.184	1.900	TBD
068440	74.25	1.905	2.245	1.414	2.271	TBD
005515	71.4	6.719	7.615	4.797	7.701	TBD
126032	35.5	7.417	4.179	2.633	4.227	TBD
126076	35	2.226	1.237	0.779	1.251	TBD
				62.296	100	TBD

1.1.5 Upgrade Laurens EC Del 40-Laurens Tie

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
023506	74	2.426	1.870	1.795	2.967	TBD
126036	58	2.426	1.466	1.407	2.325	TBD
126038	74.9	2.426	1.893	1.817	3.003	TBD
063666	55	77.083	44.162	42.396	70.060	TBD
026749	44.4	6.968	3.223	3.094	5.113	TBD
062472	55	2.142	1.227	1.178	1.947	TBD
068440	74.25	1.895	1.466	1.407	2.325	TBD
005515	71.4	6.709	4.990	4.790	7.916	TBD
126032	35.5	7.407	2.739	2.629	4.345	TBD
				60.514	100	TBD

1.2 Upgrade Lee B/W 100 kV Lines (Lee Steam Station-Shady Grove Tie)

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
017801	71.4	4.239	2.293	3.027	10.239	4.607
055960	25	4.239	0.803	1.060	3.585	1.613
062756	32	3.634	0.881	1.163	3.934	1.770
069510	40	4.111	1.246	1.644	5.563	2.503
126026	74.9	4.305	2.443	3.224	10.908	4.909
165980	37.5	6.12	1.739	2.295	7.764	3.494
063666	55	7.524	3.135	4.138	13.999	6.300
056654	25	4.416	0.836	1.104	3.735	1.681
062472	55	3.496	1.457	1.923	6.505	2.927
068440	74.25	2.824	1.589	2.097	7.093	3.192
126028	30	4.239	0.963	1.272	4.302	1.936
126068	28	4.406	0.935	1.234	4.173	1.878
005515	71.4	2.99	1.617	2.135	7.222	3.250
126076	35	3.696	0.980	1.294	4.376	1.969
126078	40	4.88	1.479	1.952	6.603	2.972
				29.561	100	45

1.3 Upgrade Newberry B/W 115 kV Lines (Bush River Tie-DESC)

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
017801	71.4	3.628	3.279	2.590	3.754	1.577
055960	25	3.628	1.148	0.907	1.315	0.552
062756	32	7.326	2.967	2.344	3.398	1.427
023506	74	5.497	5.149	4.068	5.896	2.476
126036	58	5.497	4.036	3.188	4.621	1.941
126038	74.9	5.497	5.212	4.117	5.967	2.506
069510	40	4.185	2.119	1.674	2.426	1.019
126026	74.9	3.598	3.411	2.695	3.906	1.640
165980	37.5	9.845	4.673	3.692	5.351	2.247
063666	55	7.428	5.171	4.085	5.921	2.487
026749	44.4	14.867	8.356	6.601	9.567	4.018
056654	25	7.571	2.396	1.893	2.743	1.152
062472	55	5.205	3.624	2.863	4.149	1.743
068440	74.25	3.157	2.967	2.344	3.397	1.427
126028	30	3.628	1.378	1.088	1.578	0.663
126068	28	7.571	2.683	2.120	3.073	1.290
005515	71.4	14.38	12.997	10.267	14.881	6.250
126032	35.5	15.689	7.050	5.570	8.072	3.390
126076	35	5.813	2.575	2.035	2.949	1.239
126078	40	12.134	6.144	4.854	7.035	2.955
				68.995	100	42

1.4 Upgrade Piedmont B/W 100 kV Lines (Lee Steam Station-Shady Grove Tie)

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
017801	71.4	3.986	2.372	2.846	9.804	4.412
055960	25	3.986	0.830	0.997	3.433	1.545
062756	32	3.42	0.912	1.094	3.770	1.696
069510	40	3.867	1.289	1.547	5.328	2.398
126026	74.9	4.048	2.527	3.032	10.444	4.700
165980	37.5	5.745	1.795	2.154	7.421	3.340
063666	55	7.059	3.235	3.882	13.374	6.018
026749	44.4	2.776	1.027	1.233	4.246	1.911
056654	25	4.152	0.865	1.038	3.576	1.609
062472	55	3.292	1.509	1.811	6.237	2.807
068440	74.25	2.662	1.647	1.977	6.809	3.064
126028	30	3.986	0.997	1.196	4.119	1.854
126068	28	4.142	0.966	1.160	3.995	1.798
005515	71.4	2.818	1.677	2.012	6.931	3.119
126076	35	3.478	1.014	1.217	4.193	1.887
126078	40	4.586	1.529	1.834	6.319	2.844
				29.029	100	45

2.0 Contingent Facilities

2.1 Upgrade Monroe 100 kV Lines (Lancaster Main-Monroe Main)

ID	MW Output (MW)	DFax	Loading Impact (%)	MW Impact (MW)	Cost Allocation Factor (%)	Cost Allocation ($ M)
174146	31	68.387	32.615	21.200	-	-
126022	47	1.859	1.344	0.874	-	-
022154	65	11.994	11.994	7.796	-	-
015376	15	12.051	2.781	1.808	-	-
015543	58	67.185	59.950	38.967	-	-
				70.645	-	-

TRANSMISSION PANEL EXHIBIT 4: DEP TRANSMISSION PLANNING SUPPLEMENTAL STUDY OF PROSPECTIVE SOLAR ADDITIONS FOR CAROLINAS CARBON PLAN

I. Supplemental Study Purpose

The purpose of this study was to further analyze the need for proactive transmission upgrades to help Duke Energy meet Carbon Plan and Integrated Resource Plan goals in the Carolinas. Prior studies in the serial generator interconnection process and the Transitional Cluster Study have demonstrated the need for transmission upgrades that mitigate common constraints but cannot be financed by solar generation developers. In this study, prior solar generation interconnection requests that withdrew from the queue were studied with the latest Duke Energy transmission power flow models. Cluster study methods were used to determine overloaded transmission facilities, appropriate upgrades, and contributions to the overloads by the studied solar generators.

II. Supplemental Study Assumptions and Limitations

This study started with a summer peak base case representing Transitional Cluster Study Phase 2. In DEP, only 4 requests from Transitional Cluster Study Phase 1 proceeded to Phase 2. These 4 Phase 2 generators, as well as prior generators still in the interconnection processes, were added to the most recent internal transmission planning model.

This study, along with the one performed by DEC, included 5400 MW of additional solar generation across DEC and DEP, with a split of 1900 MW studied in DEC and 3500 MW studied in DEP. DEC and DEP studies were performed independently, similar to the cluster study process, and evaluated the need for upgrades in the respective area studied. For each utility, the most recent withdrawn solar requests were selected for inclusion, going back in time until the desired total solar MW addition was reached, with the following caveats:

- Large solar plants greater than 175 MW were not included due to the high likelihood of large local upgrades to connect them to the grid;
- Some prior requests were duplicates at the same site with different assumptions but using the same solar field. In these situations, only one request was included and duplicates were removed;
- Only standard solar generation output was assumed, with storage at solar sites not considered. Thus only summer cases were studied and winter cases were not studied; and
- All geographical locations in DEP were considered, both inside and outside the current Red Zones.

Based on these parameters, 45 transmission solar projects (3527 MW) were added to the DEP Transitional Cluster Phase 2 models. See the complete list on pages 5-6 below.

It is difficult to predict future locations for solar additions, especially considering the large quantity of solar generation needed to meet Carbon Plan goals. Due to the large amount of land needed per MW of solar capacity, solar plants typically have much smaller MW sizes than conventional generation plants such as combined cycle generation. Meeting Carbon Plan goals will require dozens or more individual solar generation plants spread across the DEC and DEP systems, with concentrations expected in the NC and SC Red Zones as represented by prior solar generation requests.

This study used prior withdrawn requests as the best available data for selection of future solar locations and MW sizes. These sites were previously submitted to DEP as official interconnection requests in the FERC or state interconnection processes, indicating that there was land available at those locations at the time, along with willing landowners and other attractive local conditions. Selecting the most recent prior withdrawn requests reduces the likelihood that local conditions have changed and reduced the viability of solar generation at these sites.

While the DEC and DEP Red Zones are of particular interest in these studies, all geographic regions were considered to avoid biasing the results towards the Red Zone Expansion Plan (RZEP) transmission upgrades. Note that while the fewer number of Red Zone requests in recent years may be due to the well-known congestion and upgrade costs in the Red Zones, elimination of Red Zone congestion with pro-active upgrades may incentivize a higher concentration of Red Zone requests than seen in recent years.

DISIS 2022 requests were not considered in this study, although there could be requests in DISIS 2022 that are the same as or similar to prior requests modeled in this study.

III. Summary of Results

The results of the DEP study are summarized below, with additional details provided in the following tables.

- This analysis provides support for eleven (11) of the RZEP projects in DEP. See Table A below.
- This analysis shows that three (3) of the DEP RZEP projects can be delayed until future studies again show a need. See Table B below.
- The analysis shows the need for additional upgrades to reliably interconnect the 3527 MW of added solar generation. See Table C below.
- The scope of the transmission solutions vary from facility to facility (e.g. replacement of ancillary pieces of equipment versus rebuild of a transmission line).
- Some transmission solutions may mitigate more than one identified issue.

Table A: RZEP Upgrades Identified in DEP Supplemental Study and Recommended for Immediate Implementation

TRANSMISSION FACILITY	UPGRADE
Camden - Camden Dupont 115 kV line	Camden-Camden Dupont 115 kV line - reconductor 0.73 miles.
Camden Junction - Wateree 115 kV line	Camden Junction-DPC Wateree 115 kV line - reconductor 4.24 miles.
Cape Fear - West End 230 kV line	Cape Fear-West End 230 kV – reconductor 26 miles and raise 4.5 miles
Clayton Industrial - Selma 115 kV line / Milburnie 230 kV Substation	Milburnie 230 kV - add redundant 230 kV bus protection.
Erwin - Fayetteville 115 kV line	Erwin-Fayetteville 115 kV line – reconductor 2 sections, 8.72 miles.
Erwin - Fayetteville East 230 kV line	Erwin-Fayetteville East 230 - reconductor 23 miles.
Fayetteville - Fayetteville Dupont SS 115 kV line, section 1	Fay-Fay Dupont 115 kV line - reconductor 4.9 miles.
Fayetteville - Fayetteville Dupont SS 115 kV line, section 2	Fay-Fay Dupont 115 kV line - reconductor 3.2 miles.
Robinson - Rockingham 115 kV line	Robinson Plant-Rockingham 115 kV line - reconductor 17.08 miles.
Robinson - Rockingham 230 kV line	Robinson Plant-Rockingham 230 line - reconductor 41 miles.
Weatherspoon - Marion 115 kV line	Weatherspoon-Marion 115 kV - raise 6.45 to 38.5 miles

Table B: RZEP Upgrades NOT Identified in this Study and Recommended to be Delayed

TRANSMISSION FACILITY	UPGRADE
Rockingham – West End 230 kV West Line	Raise the line from Eden Solar to West End (replace 6 structures)
Erwin-Milburnie 230 kV Line	Raise the line from Erwin to Edmonson (replace 22 structures and upgrade 4 switches)
Sutton Plant-Wallace 230 kV Line	Raise the line from Crooked Run Solar to Wallace (replace 1 structure)

Table C: Other Upgrades Identified

TRANSMISSION FACILITY	UPGRADE
Badin 115/100 kV transformer #1	Replace Badin 115/100 kV transformers with 168 MVA units. Owned by Cube Hydro.[1]
Badin 115/100 kV transformer #2	Replace Badin 115/100 kV transformers with 168 MVA units. Owned by Cube Hydro.
Blewett - Tillery 115 kV line	Uprate CT ratios at both ends to get 119 MVA summer rating.
Camden - Camden Junction 115 kV line	Reconductor 7.74 miles of Camden-Camden Junction 115 kV line.
Camden Dupont - Wateree 115 kV line	Camden Dupont-DPC Wateree 115 kV line - raise 3.45 mile section
Cape Fear - Biscoe 115 kV line	Reconductor 19.6 mile section between Cape Fear and Q517.
Cape Fear - Method 115 kV line	Raise Cape Fear-Moncure (0.68 mi) and Moncure-Fuquay Wade Nash (11.3 mi) sections
Florence Dupont - Marion 115 kV line	Upgrade jumpers at Marion substation.
Laurinburg - Raeford 115 kV line	Make Laurinburg 230 double breaker by moving the Weatherspoon line to bay 3.
Lee - Milburnie 230 kV line / Selma 230 kV Substation	Selma 230 Substation - make into a 4 breaker ring bus on the 230 kV side, and add redundant 230 kV bus protection
Lee - Selma 115 kV line	Reconductor Lee-Rosewood and Princeton-Kenly sections of Lee-Selma 115 kV line – 6.4 miles.
Lilesville - Oakboro 230 kV Black line	Raise conductor for Lilesville-DPC Oakboro Black 230 kV line (30 mi).
Lilesville - Oakboro 230 kV White line	Raise conductor for Lilesville-DPC Oakboro White 230 kV line (30 mi).
Tillery - Badin 115 kV Black & White lines	Raise 14.57 miles of Tillery Plant-Alcoa Badin 115 kV Black & White lines.
Weatherspoon - Raeford 115 kV line	Weatherspoon-Raeford 115 kV line reconductor 21 miles

[1] Analysis of affected systems were beyond scope of the study; however, the Companies did identify impacted tie lines, which can be partially or fully owned by neighboring utilities.

IV. Detailed Data and Results

The following table lists the generators included in the DEP Supplemental Study. Detailed results of the study are provided at Section 1.0 below.

Queue #	MW (Summer Peak)	Point of Interconnection
383	80	Cumberland-Whiteville 230
387	70.1	Marion-Whiteville 230
426	74.5	Robinson-Rockingham 115, Pageland Tap
437	80	Florence DuPont-Marion 115
456	80	Jacksonville-New Bern 230
457	74.9	Florence-Kingstree 230
461	80	Roxboro-E. Danville 230
462	20	Roxboro-E. Danville 230
469.429	72.54	Robinson-Rockingham 230, Cheraw Reid Park Tap
469.430	77.53	Weatherspoon-Raeford 115
469.434	63	Darlington-Bennettsville 230
469.435	75	Robinson-Florence 230
469.444	75	Florence DuPont-SCPSA Hemingway 115
469.454	80	Robinson-Camden Jct 115
469.458	8	Kinston DuPont 115 Sub)
469.459	8	Kinston DuPont 115 Sub
470	50	Erwin-Selma 230
471	80	Camden Jct - Wateree 115
473	78.32	Person-Rocky Mount 230
478	80	New Bern-Wommack 230 South
501	74.9	Bennettsville-Laurinburg 230
502	60	Rockingham-West End 230 East
503.408	80	New Bern-Wommack 230 North
503.423	80	Roxboro-Falls 230
503.447	80	Jacksonville-Wallace 230
503.465	80	Lee-Wommack 230 North
503.469	74.9	Robinson-Sumter 230
503.486	74.9	Robinson-Sumter 230
506	80	Robinson-Florence-230
510	74	Weatherspoon-LOF 115
511	74	Weatherspoon-Raeford 115
512	71.3	Erwin-Fayetteville East 230
513	74	Laurinburg-Raeford 115
514	72	Lee-Wallace 115
516	80	Cape Fear-West End 230
517	80	Cape Fear-Biscoe 115
518	80	Cumberland-Delco 230
519	80	Fayetteville-Rockingham 230

Queue #	MW (Summer Peak)	Point of Interconnection
520	80	Biscoe-Rockingham 230
521	80	Erwin-Selma 230
523	145	Lee-Wommack 230 South
524	150	Florence-Kingstree 230
527	160	Bennettsville-Laurinburg 230
528	165	Darlington County Plant 230 Switchyard
529	69.9	Bennettsville-Laurinburg 230

1.0 RZEP Projects – Detailed DEP Supplemental Study Results

1.1 Reconductor Cape Fear – West End 230 kV line

1.1.1 CEMC Center Church – Q516 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q516	80	53.975	43.180	8.147	45.12	1.77
Q502	60	13.537	8.122	1.532	8.49	0.33
Q519	80	7.021	5.617	1.060	5.87	0.23
Q469.429	72.54	6.351	4.607	0.869	4.81	0.19
Q426	74.5	5.499	4.097	0.773	4.28	0.17
Q506	80	4.281	3.425	0.646	3.58	0.14
Q529	69.9	3.940	2.754	0.520	2.88	0.11
Q501	74.9	3.747	2.807	0.530	2.93	0.11
Q513	74	3.648	2.700	0.509	2.82	0.11
Q527	160	3.586	5.738	1.083	5.99	0.23
Q510	74	3.488	2.581	0.487	2.70	0.11
Q469.434	63	3.399	2.141	0.404	2.24	0.09
Q528	165	3.369	5.559	1.049	5.81	0.23
Q469.435	75	3.176	2.382	0.449	2.49	0.10
Q469.454	80	2.958	2.366	0.446	0.00	0.00
Q503.469	74.9	2.922	2.189	0.413	0.00	0.00
Q503.486	74.9	2.738	2.051	0.387	0.00	0.00
Q471	80	2.568	2.054	0.388	0.00	0.00
Q511	74	2.551	1.888	0.356	0.00	0.00
Q469.444	75	2.519	1.889	0.356	0.00	0.00
Q437	80	2.516	2.013	0.380	0.00	0.00

Q469.430	77.53	2.510	1.946	0.367	0.00	0.00
Q457	74.9	2.502	1.874	0.354	0.00	0.00
Q524	150	2.462	3.693	0.697	0.00	0.00
Q387	70.1	1.797	1.260	0.238	0.00	0.00
Q383	80	1.383	1.106	0.209	0.00	0.00
Q520	80	0.873	0.698	0.132	0.00	0.00
Q518	80	0.351	0.281	0.053	0.00	0.00
			121.02	22.83	100.00	3.91

1.1.2 West End 230 – Q516 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation ($ M)
Q502	60	13.537	8.122	1.532	15.46	6.29
Q519	80	7.021	5.617	1.060	10.69	4.35
Q469.429	72.54	6.351	4.607	0.869	8.77	3.57
Q426	74.5	5.499	4.097	0.773	7.80	3.17
Q506	80	4.281	3.425	0.646	6.52	2.65
Q529	69.9	3.94	2.754	0.520	5.24	2.13
Q501	74.9	3.747	2.807	0.530	5.34	2.17
Q513	74	3.648	2.700	0.509	5.14	2.09
Q527	160	3.586	5.738	1.083	10.92	4.44
Q510	74	3.488	2.581	0.487	4.91	2.00
Q469.434	63	3.399	2.141	0.404	4.08	1.66
Q528	165	3.369	5.559	1.049	10.58	4.30
Q469.435	75	3.176	2.382	0.449	4.53	1.84
Q469.454	80	2.958	2.366	0.446	0.00	0.00
Q503.469	74.9	2.922	2.189	0.413	0.00	0.00
Q503.486	74.9	2.738	2.051	0.387	0.00	0.00
Q471	80	2.568	2.054	0.388	0.00	0.00
Q511	74	2.551	1.888	0.356	0.00	0.00
Q469.444	75	2.519	1.889	0.356	0.00	0.00
Q437	80	2.516	2.013	0.380	0.00	0.00
Q469.430	77.53	2.51	1.946	0.367	0.00	0.00
Q457	74.9	2.502	1.874	0.354	0.00	0.00
Q524	150	2.462	3.693	0.697	0.00	0.00
Q387	70.1	1.797	1.260	0.238	0.00	0.00

Q383	80	1.383	1.106	0.209	0.00	0.00
Q520	80	0.873	0.698	0.132	0.00	0.00
Q518	80	0.351	0.281	0.053	0.00	0.00
			77.84	14.69	100.00	40.65

1.1.3 Sanford US1 – Sanford Garden St. Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q516	80	53.975	43.180	8.450	45.12	3.13
Q502	60	13.537	8.122	1.589	8.49	0.59
Q519	80	7.021	5.617	1.099	5.87	0.41
Q469.429	72.54	6.351	4.607	0.902	4.81	0.33
Q426	74.5	5.499	4.097	0.802	4.28	0.30
Q506	80	4.281	3.425	0.670	3.58	0.25
Q529	69.9	3.94	2.754	0.539	2.88	0.20
Q501	74.9	3.747	2.807	0.549	2.93	0.20
Q513	74	3.648	2.700	0.528	2.82	0.20
Q527	160	3.586	5.738	1.123	5.99	0.42
Q510	74	3.488	2.581	0.505	2.70	0.19
Q469.434	63	3.399	2.141	0.419	2.24	0.16
Q528	165	3.369	5.559	1.088	5.81	0.40
Q469.435	75	3.176	2.382	0.466	2.49	0.17
Q469.454	80	2.958	2.366	0.463	0.00	0.00
Q503.469	74.9	2.922	2.189	0.428	0.00	0.00
Q503.486	74.9	2.738	2.051	0.401	0.00	0.00
Q471	80	2.568	2.054	0.402	0.00	0.00
Q511	74	2.551	1.888	0.369	0.00	0.00
Q469.444	75	2.519	1.889	0.370	0.00	0.00
Q437	80	2.516	2.013	0.394	0.00	0.00
Q469.430	77.53	2.51	1.946	0.381	0.00	0.00
Q457	74.9	2.502	1.874	0.367	0.00	0.00
Q524	150	2.462	3.693	0.723	0.00	0.00
Q387	70.1	1.797	1.260	0.247	0.00	0.00
Q383	80	1.383	1.106	0.217	0.00	0.00
Q520	80	0.873	0.698	0.137	0.00	0.00
Q518	80	0.351	0.281	0.055	0.00	0.00

			121.02	23.68	100.00	6.94

1.1.4 San Garden St. – CEMC Center Ch. Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q516	80	53.975	43.180	7.982	45.12	7.36
Q502	60	13.537	8.122	1.501	8.49	1.38
Q519	80	7.021	5.617	1.038	5.87	0.96
Q469.429	72.54	6.351	4.607	0.852	4.81	0.79
Q426	74.5	5.499	4.097	0.757	4.28	0.70
Q506	80	4.281	3.425	0.633	3.58	0.58
Q529	69.9	3.94	2.754	0.509	2.88	0.47
Q501	74.9	3.747	2.807	0.519	2.93	0.48
Q513	74	3.648	2.700	0.499	2.82	0.46
Q527	160	3.586	5.738	1.061	5.99	0.98
Q510	74	3.488	2.581	0.477	2.70	0.44
Q469.434	63	3.399	2.141	0.396	2.24	0.36
Q528	165	3.369	5.559	1.028	5.81	0.95
Q469.435	75	3.176	2.382	0.440	2.49	0.41
Q469.454	80	2.958	2.366	0.437	0.00	0.00
Q503.469	74.9	2.922	2.189	0.405	0.00	0.00
Q503.486	74.9	2.738	2.051	0.379	0.00	0.00
Q471	80	2.568	2.054	0.380	0.00	0.00
Q511	74	2.551	1.888	0.349	0.00	0.00
Q469.444	75	2.519	1.889	0.349	0.00	0.00
Q437	80	2.516	2.013	0.372	0.00	0.00
Q469.430	77.53	2.51	1.946	0.360	0.00	0.00
Q457	74.9	2.502	1.874	0.346	0.00	0.00
Q524	150	2.462	3.693	0.683	0.00	0.00
Q387	70.1	1.797	1.260	0.233	0.00	0.00
Q383	80	1.383	1.106	0.205	0.00	0.00
Q520	80	0.873	0.698	0.129	0.00	0.00
Q518	80	0.351	0.281	0.052	0.00	0.00

			121.02	22.37	100.00	16.31

1.1.5 Sanford Deep River – Sanford Horner Blvd. Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q516	80	53.975	43.180	8.584	45.12	1.15
Q502	60	13.537	8.122	1.615	8.49	0.22
Q519	80	7.021	5.617	1.117	5.87	0.15
Q469.429	72.54	6.351	4.607	0.916	4.81	0.12
Q426	74.5	5.499	4.097	0.814	4.28	0.11
Q506	80	4.281	3.425	0.681	3.58	0.09
Q529	69.9	3.94	2.754	0.548	2.88	0.07
Q501	74.9	3.747	2.807	0.558	2.93	0.07
Q513	74	3.648	2.700	0.537	2.82	0.07
Q527	160	3.586	5.738	1.141	5.99	0.15
Q510	74	3.488	2.581	0.513	2.70	0.07
Q469.434	63	3.399	2.141	0.426	2.24	0.06
Q528	165	3.369	5.559	1.105	5.81	0.15
Q469.435	75	3.176	2.382	0.474	2.49	0.06
Q469.454	80	2.958	2.366	0.470	0.00	0.00
Q503.469	74.9	2.922	2.189	0.435	0.00	0.00
Q503.486	74.9	2.738	2.051	0.408	0.00	0.00
Q471	80	2.568	2.054	0.408	0.00	0.00
Q511	74	2.551	1.888	0.375	0.00	0.00
Q469.444	75	2.519	1.889	0.376	0.00	0.00
Q437	80	2.516	2.013	0.400	0.00	0.00
Q469.430	77.53	2.51	1.946	0.387	0.00	0.00
Q457	74.9	2.502	1.874	0.373	0.00	0.00
Q524	150	2.462	3.693	0.734	0.00	0.00
Q387	70.1	1.797	1.260	0.250	0.00	0.00
Q383	80	1.383	1.106	0.220	0.00	0.00
Q520	80	0.873	0.698	0.139	0.00	0.00
Q518	80	0.351	0.281	0.056	0.00	0.00

			121.02	24.06	100.00	2.54

1.2 Reconductor Erwin – Fayetteville East 230 kV Line

1.2.1 Erwin 230 – Q512 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q512	71.3	67.386	48.046	8.881	32.32	9.38
Q511	74	8.851	6.550	1.211	4.41	1.28
Q469.430	77.53	8.651	6.707	1.240	4.51	1.31
Q513	74	6.742	4.989	0.922	3.36	0.97
Q510	74	6.37	4.714	0.871	3.17	0.92
Q519	80	6.144	4.915	0.909	3.31	0.96
Q383	80	6.093	4.874	0.901	3.28	0.95
Q529	69.9	5.45	3.810	0.704	2.56	0.74
Q501	74.9	5.215	3.906	0.722	2.63	0.76
Q527	160	5.02	8.032	1.485	5.40	1.57
Q387	70.1	4.71	3.302	0.610	2.22	0.64
Q437	80	4.52	3.616	0.668	2.43	0.71
Q469.429	72.54	4.346	3.153	0.583	2.12	0.62
Q518	80	4.144	3.315	0.613	2.23	0.65
Q502	60	4.098	2.459	0.454	1.65	0.48
Q426	74.5	4.094	3.050	0.564	2.05	0.60
Q469.434	63	4.075	2.567	0.475	1.73	0.50
Q506	80	3.975	3.180	0.588	2.14	0.62
Q469.435	75	3.949	2.962	0.547	1.99	0.58
Q469.444	75	3.861	2.896	0.535	1.95	0.57
Q528	165	3.812	6.290	1.163	4.23	1.23
Q457	74.9	3.501	2.622	0.485	1.76	0.51
Q524	150	3.455	5.183	0.958	3.49	1.01
Q503.469	74.9	3.371	2.525	0.467	1.70	0.49
Q469.454	80	3.255	2.604	0.481	1.75	0.51
Q503.486	74.9	3.204	2.400	0.444	1.61	0.47
Q471	80	2.857	2.286	0.422	0.00	0.00

Q520	80	0.607	0.486	0.090	0.00	0.00
			151.44	27.99	100.00	29.04

1.2.2 Linden Sub – Q512 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q511	74	8.851	6.550	1.211	6.51	0.69
Q469.430	77.53	8.651	6.707	1.240	6.67	0.71
Q513	74	6.742	4.989	0.922	4.96	0.53
Q510	74	6.37	4.714	0.871	4.68	0.50
Q519	80	6.144	4.915	0.909	4.88	0.52
Q383	80	6.093	4.874	0.901	4.84	0.52
Q529	69.9	5.45	3.810	0.704	3.79	0.40
Q501	74.9	5.215	3.906	0.722	3.88	0.41
Q527	160	5.02	8.032	1.485	7.98	0.85
Q387	70.1	4.71	3.302	0.610	3.28	0.35
Q437	80	4.52	3.616	0.668	3.59	0.38
Q469.429	72.54	4.346	3.153	0.583	3.13	0.33
Q518	80	4.144	3.315	0.613	3.29	0.35
Q502	60	4.098	2.459	0.454	2.44	0.26
Q426	74.5	4.094	3.050	0.564	3.03	0.32
Q469.434	63	4.075	2.567	0.475	2.55	0.27
Q506	80	3.975	3.180	0.588	3.16	0.34
Q469.435	75	3.949	2.962	0.547	2.94	0.31
Q469.444	75	3.861	2.896	0.535	2.88	0.31
Q528	165	3.812	6.290	1.163	6.25	0.67
Q457	74.9	3.501	2.622	0.485	2.61	0.28
Q524	150	3.455	5.183	0.958	5.15	0.55
Q503.469	74.9	3.371	2.525	0.467	2.51	0.27
Q469.454	80	3.255	2.604	0.481	2.59	0.28
Q503.486	74.9	3.204	2.400	0.444	2.39	0.25
Q471	80	2.857	2.286	0.422	0.00	0.00
Q520	80	0.607	0.486	0.090	0.00	0.00
			103.39	19.11	100.00	10.65

1.2.3 Linden Sub – Fayetteville East 230 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q511	74	8.851	6.550	1.211	6.51	2.88
Q469.430	77.53	8.651	6.707	1.240	6.67	2.95
Q513	74	6.742	4.989	0.922	4.96	2.19
Q510	74	6.37	4.714	0.871	4.68	2.07
Q519	80	6.144	4.915	0.909	4.88	2.16
Q383	80	6.093	4.874	0.901	4.84	2.14
Q529	69.9	5.45	3.810	0.704	3.79	1.68
Q501	74.9	5.215	3.906	0.722	3.88	1.72
Q527	160	5.02	8.032	1.485	7.98	3.53
Q387	70.1	4.71	3.302	0.610	3.28	1.45
Q437	80	4.52	3.616	0.668	3.59	1.59
Q469.429	72.54	4.346	3.153	0.583	3.13	1.39
Q518	80	4.144	3.315	0.613	3.29	1.46
Q502	60	4.098	2.459	0.454	2.44	1.08
Q426	74.5	4.094	3.050	0.564	3.03	1.34
Q469.434	63	4.075	2.567	0.475	2.55	1.13
Q506	80	3.975	3.180	0.588	3.16	1.40
Q469.435	75	3.949	2.962	0.547	2.94	1.30
Q469.444	75	3.861	2.896	0.535	2.88	1.27
Q528	165	3.812	6.290	1.163	6.25	2.77
Q457	74.9	3.501	2.622	0.485	2.61	1.15
Q524	150	3.455	5.183	0.958	5.15	2.28
Q503.469	74.9	3.371	2.525	0.467	2.51	1.11
Q469.454	80	3.255	2.604	0.481	2.59	1.15
Q503.486	74.9	3.204	2.400	0.444	2.39	1.06
Q471	80	2.857	2.286	0.422	0.00	0.00
Q520	80	0.607	0.486	0.090	0.00	0.00
			103.39	19.11	100.00	44.25

1.3 Reconductor Erwin – Fayetteville 115 kV Line

1.3.1 Bear – Fay Slocomb Tap Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q527	160	1.243	1.989	1.671	19.36	0.91
Q527	165	0.925	1.526	1.283	14.86	0.70
Q430	77.53	1.958	1.518	1.276	14.78	0.69
Q511	74	1.915	1.417	1.191	13.80	0.65
Q524	150	0.878	1.317	1.107	12.82	0.60
Q510	74	1.704	1.261	1.060	12.28	0.58
Q383	80	1.553	1.242	1.044	12.10	0.57
Q513	74	1.58	1.169	0.983	0.00	0.00
Q519	80	1.269	1.015	0.853	0.00	0.00
Q437	80	1.235	0.988	0.830	0.00	0.00
Q518	80	1.227	0.982	0.825	0.00	0.00
Q501	74.9	1.282	0.960	0.807	0.00	0.00
Q529	69.9	1.329	0.929	0.781	0.00	0.00
Q387	70.1	1.279	0.897	0.753	0.00	0.00
Q469.444	75	1.011	0.758	0.637	0.00	0.00
Q506	80	0.924	0.739	0.621	0.00	0.00
Q469.435	75	0.985	0.739	0.621	0.00	0.00
Q429	72.54	0.919	0.667	0.560	0.00	0.00
Q457	74.9	0.889	0.666	0.560	0.00	0.00
Q426	74.5	0.885	0.659	0.554	0.00	0.00
Q469.434	63	0.996	0.627	0.527	0.00	0.00
Q469.454	80	0.775	0.620	0.521	0.00	0.00
Q503.469	74.9	0.817	0.612	0.514	0.00	0.00
Q503.486	74.9	0.777	0.582	0.489	0.00	0.00
Q471	80	0.672	0.538	0.452	0.00	0.00
Q502	60	0.75	0.450	0.378	0.00	0.00

			35.14	20.90	100.00	4.69

1.3.2 Beard - SREMC Wade Tap Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q527	160	1.243	1.989	1.671	19.36	3.21
Q527	165	0.925	1.526	1.283	14.86	2.47
Q430	77.53	1.958	1.518	1.276	14.78	2.45
Q511	74	1.915	1.417	1.191	13.80	2.29
Q524	150	0.878	1.317	1.107	12.82	2.13
Q510	74	1.704	1.261	1.060	12.28	2.04
Q383	80	1.553	1.242	1.044	12.10	2.01
Q513	74	1.58	1.169	0.983	0	0.00
Q519	80	1.269	1.015	0.853	0	0.00
Q437	80	1.235	0.988	0.830	0	0.00
Q518	80	1.227	0.982	0.825	0	0.00
Q501	74.9	1.282	0.960	0.807	0	0.00
Q529	69.9	1.329	0.929	0.781	0	0.00
Q387	70.1	1.279	0.897	0.753	0	0.00
Q469.444	75	1.011	0.758	0.637	0	0.00
Q506	80	0.924	0.739	0.621	0	0.00
Q469.435	75	0.985	0.739	0.621	0	0.00
Q429	72.54	0.919	0.667	0.560	0	0.00
Q457	74.9	0.889	0.666	0.560	0	0.00
Q426	74.5	0.885	0.659	0.554	0	0.00
Q469.434	63	0.996	0.627	0.527	0	0.00
Q469.454	80	0.775	0.620	0.521	0	0.00
Q503.469	74.9	0.817	0.612	0.514	0	0.00
Q503.486	74.9	0.777	0.582	0.489	0	0.00
Q471	80	0.672	0.538	0.452	0	0.00
Q502	60	0.75	0.450	0.378	0	0.00
			35.14	20.90	100.00	16.60

1.4 Reconductor Fayetteville – Fayetteville Dupont SS 115 kV Line

1.4.1 Fayetteville – Hope Mills Church St. Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q527	160	2.335	3.736	3.139	13.02	1.51
Q510	74	4.775	3.534	2.969	12.31	1.43
Q469.430	77.53	3.306	2.563	2.154	8.93	1.04
Q524	150	1.663	2.495	2.096	8.69	1.01
Q528	165	1.511	2.493	2.095	8.69	1.01
Q437	80	2.853	2.282	1.918	7.95	0.92
Q513	74	2.772	2.051	1.724	7.15	0.83
Q511	74	2.481	1.836	1.543	6.40	0.74
Q501	74.9	2.394	1.793	1.507	6.25	0.72
Q529	69.9	2.465	1.723	1.448	6.01	0.70
Q469.444	75	2.097	1.573	1.322	5.48	0.64
Q469.435	75	1.797	1.348	1.133	4.70	0.54
Q457	74.9	1.691	1.267	1.064	4.41	0.51
Q469.434	63	1.7	1.071	0.900	0.00	0.00
Q387	70.1	1.485	1.041	0.875	0.00	0.00
Q503.469	74.9	1.319	0.988	0.830	0.00	0.00
Q506	80	1.195	0.956	0.803	0.00	0.00
Q503.486	74.9	1.253	0.938	0.789	0.00	0.00
Q469.454	80	1.156	0.925	0.777	0.00	0.00
Q471	80	0.949	0.759	0.638	0.00	0.00
Q426	74.5	0.666	0.496	0.417	0.00	0.00
Q469.429	72.54	0.47	0.341	0.287	0.00	0.00
			35.87	30.14	100.00	11.60

1.4.2 Hope Mills Church St. – Roslin Solar Tap Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q527	160	2.335	3.736	3.139	13.02	1.84
Q510	74	4.775	3.534	2.969	12.31	1.74
Q469.430	77.53	3.306	2.563	2.154	8.93	1.26
Q524	150	1.663	2.495	2.096	8.69	1.23
Q528	165	1.511	2.493	2.095	8.69	1.23
Q437	80	2.853	2.282	1.918	7.95	1.12
Q513	74	2.772	2.051	1.724	7.15	1.01
Q511	74	2.481	1.836	1.543	6.40	0.90
Q501	74.9	2.394	1.793	1.507	6.25	0.88
Q529	69.9	2.465	1.723	1.448	6.01	0.85
Q469.444	75	2.097	1.573	1.322	5.48	0.77
Q469.435	75	1.797	1.348	1.133	4.70	0.66
Q457	74.9	1.691	1.267	1.064	4.41	0.62
Q469.434	63	1.7	1.071	0.900	0.00	0.00
Q387	70.1	1.485	1.041	0.875	0.00	0.00
Q503.469	74.9	1.319	0.988	0.830	0.00	0.00
Q506	80	1.195	0.956	0.803	0.00	0.00
Q503.486	74.9	1.253	0.938	0.789	0.00	0.00
Q469.454	80	1.156	0.925	0.777	0.00	0.00
Q471	80	0.949	0.759	0.638	0.00	0.00
Q426	74.5	0.666	0.496	0.417	0.00	0.00
Q469.429	72.54	0.47	0.341	0.287	0.00	0.00
			36.21	30.43	100.00	14.11

1.5 Milburnie 230 kV Substation – Add Redundant 230 kV Bus Protection

1.5.1 Smithfield Tap – Selma 115 Section of Clayton Industrial – Selma 115 kV Line

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q521	80	3.142	2.514	1.251	24.13	1.04
Q470	50	3.018	1.509	0.751	14.49	0.63
Q523	145	2.932	4.251	2.115	40.82	1.77
Q503.465	80	2.676	2.141	1.065	20.56	0.89
Q503.408	80	2.018	1.614	0.803	0.00	0.00
Q478	80	1.956	1.565	0.779	0.00	0.00
Q469.458	8	1.942	0.155	0.077	0.00	0.00
Q469.459	8	1.942	0.155	0.077	0.00	0.00
Q514	72	1.715	1.235	0.614	0.00	0.00
Q456	80	1.506	1.205	0.599	0.00	0.00
Q503.447	80	1.228	0.982	0.489	0.00	0.00
Q512	71.3	0.285	0.203	0.101	0.00	0.00
			17.53	8.72	100.00	4.32

1.6 Reconductor Weatherspoon – Marion 115 kV Line

1.6.1 Marion 115 – Dillon Tap Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q437	80	8.844	7.075	7.294	23.58	3.07
Q524	150	2.623	3.935	4.056	13.11	1.70
Q469.444	75	4.84	3.630	3.742	12.10	1.57
Q528	165	1.79	2.954	3.045	9.84	1.28
Q457	74.9	2.652	1.986	2.048	6.62	0.86
Q469.435	75	2.475	1.856	1.914	6.19	0.80
Q387	70.1	2.55	1.788	1.843	5.96	0.77
Q503.469	74.9	1.661	1.244	1.283	4.15	0.54
Q503.486	74.9	1.612	1.207	1.245	4.02	0.52
Q469.454	80	1.427	1.142	1.177	3.81	0.49
Q527	160	0.706	1.130	1.165	3.77	0.49
Q506	80	1.298	1.038	1.071	3.46	0.45
Q469.434	63	1.614	1.017	1.048	3.39	0.44
Q471	80	1.167	0.934	0.962	0.00	0.00
Q426	74.5	0.49	0.365	0.376	0.00	0.00
Q383	80	0.293	0.234	0.242	0.00	0.00
Q469.429	72.54	0.107	0.078	0.080	0.00	0.00
Q501	74.9	0.095	0.071	0.073	0.00	0.00
			31.68	32.66	100.00	13.00

1.7 Reconductor Camden – Camden Dupont 115 kV Line

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q471	80	14.6	11.680	10.916	31.15	0.81
Q469.454	80	9.761	7.809	7.298	20.82	0.54
Q528	165	2.44	4.026	3.763	10.74	0.28
Q524	150	1.784	2.676	2.501	7.14	0.19
Q469.435	75	2.146	1.610	1.504	4.29	0.11
Q503.469	74.9	2.107	1.578	1.475	4.21	0.11
Q503.486	74.9	1.993	1.493	1.395	3.98	0.10
Q506	80	1.844	1.475	1.379	3.93	0.10
Q457	74.9	1.796	1.345	1.257	3.59	0.09
Q527	160	0.831	1.330	1.243	3.55	0.09
Q469.434	63	2.084	1.313	1.227	3.50	0.09
Q469.444	75	1.554	1.166	1.089	3.11	0.08
Q426	74.5	1.273	0.948	0.886	0.00	0.00
Q437	80	1.142	0.914	0.854	0.00	0.00
Q501	74.9	0.617	0.462	0.432	0.00	0.00
Q469.429	72.54	0.48	0.348	0.325	0.00	0.00
Q387	70.1	0.423	0.297	0.277	0.00	0.00
Q529	69.9	0.36	0.252	0.235	0.00	0.00
			40.72	38.06	100.00	2.60

1.8 Reconductor Camden Junction – Camden DPC Wateree 115 kV Line

1.8.1 Wateree 115 – Q471 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q471	80	63.407	50.726	39.020	58.51	5.85
Q469.454	80	39	31.200	24.000	35.99	3.60
Q426	74.5	2.837	2.114	1.626	2.44	0.24
Q528	165	1.606	2.650	2.038	3.06	0.31
Q469.435	75	1.396	1.047	0.805	0.00	0.00
Q506	80	1.373	1.098	0.845	0.00	0.00
Q469.434	63	1.27	0.800	0.615	0.00	0.00
Q503.469	74.9	0.782	0.586	0.451	0.00	0.00
Q503.486	74.9	0.393	0.294	0.226	0.00	0.00
Q469.429	72.54	0.269	0.195	0.150	0.00	0.00
Q437	80	0.192	0.154	0.118	0.00	0.00
Q527	160	0.131	0.210	0.161	0.00	0.00
Q469.444	75	0.106	0.080	0.061	0.00	0.00
Q501	74.9	0.001	0.001	0.001	0.00	0.00
			91.15	70.12	100.00	10.00

1.9 Reconductor Robinson Plant – Rockingham 115 kV Line

1.9.1 Cordova Tap – Rockingham Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q426	74.5	48.552	36.171	25.295	45.67	4.07
Q469.454	80	5.357	4.286	2.997	5.41	0.48
Q469.429	72.54	4.626	3.356	2.347	4.24	0.38
Q506	80	4.626	3.701	2.588	4.67	0.42
Q528	165	4.448	7.339	5.132	9.27	0.83
Q469.435	75	3.968	2.976	2.081	3.76	0.34
Q434	63	3.745	2.359	1.650	2.98	0.27
Q503.469	74.9	3.661	2.742	1.918	3.46	0.31
Q471	80	3.557	2.846	1.990	3.59	0.32
Q503.486	74.9	3.303	2.474	1.730	3.12	0.28
Q457	74.9	2.524	1.890	1.322	2.39	0.21
Q524	150	2.447	3.671	2.567	4.63	0.41
Q469.444	75	2.392	1.794	1.255	2.27	0.20
Q437	80	1.9	1.520	1.063	1.92	0.17
Q527	160	1.298	2.077	1.452	2.62	0.23
Q501	74.9	0.911	0.682	0.477	0.00	0.00
Q387	70.1	0.782	0.548	0.383	0.00	0.00
Q529	69.9	0.446	0.312	0.218	0.00	0.00
			80.74	56.46	100.00	8.92

1.9.2 Cordova Tap – Sneedsboro Solar Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q426	74.5	48.552	36.171	22.191	46.56	13.54
Q528	165	4.448	7.339	4.503	9.45	2.75
Q469.454	80	5.357	4.286	2.629	5.52	1.60
Q506	80	4.626	3.701	2.270	4.76	1.39
Q524	150	2.447	3.671	2.252	4.73	1.37
Q469.429	72.54	4.626	3.356	2.059	4.32	1.26
Q469.435	75	3.968	2.976	1.826	3.83	1.11
Q471	80	3.557	2.846	1.746	3.66	1.07
Q503.469	74.9	3.661	2.742	1.682	3.53	1.03
Q503.486	74.9	3.303	2.474	1.518	3.18	0.93
Q434	63	3.745	2.359	1.447	3.04	0.88
Q527	160	1.298	2.077	1.274	2.67	0.78
Q457	74.9	2.524	1.890	1.160	2.43	0.71
Q469.444	75	2.392	1.794	1.101	2.31	0.67
Q437	80	1.9	1.520	0.933	0.00	0.00
Q501	74.9	0.911	0.682	0.419	0.00	0.00
Q387	70.1	0.782	0.548	0.336	0.00	0.00
Q529	69.9	0.446	0.312	0.191	0.00	0.00
			80.74	49.54	100.00	29.08

1.10 Reconductor Robinson Plant – Rockingham 230 kV Line

1.10.1 Cheraw Tap – Rockingham 230 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q528	165	18.124	29.905	5.528	12.43	5.36
Q529	69.9	12.532	8.760	1.619	3.64	1.57
Q387	70.1	3.7	2.594	0.479	1.08	0.46
Q426	74.5	4.331	3.227	0.596	1.34	0.58
Q469.429	72.54	60.486	43.877	8.110	18.24	7.86
Q469.435	75	15.856	11.892	2.198	4.94	2.13
Q437	80	8.093	6.474	1.197	2.69	1.16
Q469.434	63	16.783	10.573	1.954	4.40	1.89
Q469.444	75	9.584	7.188	1.329	2.99	1.29
Q469.454	80	12.701	10.161	1.878	4.22	1.82
Q457	74.9	10.269	7.691	1.422	3.20	1.38
Q503.469	74.9	14.818	11.099	2.052	4.61	1.99
Q471	80	9.775	7.820	1.445	3.25	1.40
Q503.486	74.9	13.37	10.014	1.851	4.16	1.79
Q501	74.9	12.532	9.386	1.735	3.90	1.68
Q506	80	31.012	24.810	4.586	10.32	4.45
Q524	150	9.99	14.985	2.770	6.23	2.69
Q527	160	12.532	20.051	3.706	8.34	3.59
			240.506	44.456	100.000	43.100

1.10.2 Cheraw Tap – Q506 Section

Generator	MW Output (MW)	DFax (%)	MW Impact (MW)	Loading Impact (%)	Cost Allocation Factor (%)	Cost Allocation (MM $)
Q528	165	18.124	29.905	6.390	15.21	6.55
Q529	69.9	12.532	8.760	1.872	4.46	1.92
Q387	70.1	3.7	2.594	0.554	1.32	0.57
Q426	74.5	4.331	3.227	0.689	1.64	0.71
Q469.435	75	15.856	11.892	2.541	6.05	2.61
Q437	80	8.093	6.474	1.383	3.29	1.42
Q469.434	63	16.783	10.573	2.259	5.38	2.32
Q469.444	75	9.584	7.188	1.536	3.66	1.58
Q469.454	80	12.701	10.161	2.171	5.17	2.23
Q457	74.9	10.269	7.691	1.643	3.91	1.69
Q503.469	74.9	14.818	11.099	2.372	5.64	2.43
Q471	80	9.775	7.820	1.671	3.98	1.71
Q503.486	74.9	13.37	10.014	2.140	5.09	2.20
Q501	74.9	12.532	9.386	2.006	4.77	2.06
Q506	80	31.012	24.810	5.301	12.62	5.44
Q524	150	9.99	14.985	3.202	7.62	3.28
Q527	160	12.532	20.051	4.284	10.20	4.40
			196.630	42.015	100.000	43.100

**Confidential version filed separately

Public Version

Transmission Map Showing Greenville, Havelock, and New Bern Substations

[redacted]