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NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

July 19, 2023

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-7, Sub 1276 – Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance Based Regulation

Dear Ms. Dunston:

Attached for filing on behalf of the Public Staff in the above-referenced docket is the public version of the testimony and exhibits of consultant, John W. Chiles, Principal in the Transmission Services Group at GDS Associates, Inc.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. Confidential information is located on pages 27-28 of the testimony. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
/s/ Lucy E. Edmondson
Chief Counsel
lucy.edmondson@psncuc.nc.gov

/s/ Robert B. Josey
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/s/ Nadia L. Luhr
Staff Attorney
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Attachments

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CERTIFICATE OF SERVICE

I certify that a copy of this Testimony with exhibits has been served on all parties of record or their attorneys, or both, in accordance with Commission Rule R1-39, by United States mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 19th day of July, 2023.

Electronically submitted
/s/Nadia Luhr
Staff Attorney

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	**TESTIMONY OF**
for Adjustment of Rates and Charges	)	**JOHN W. CHILES ON**
Applicable to Electric Service in North	)	**BEHALF OF THE**
Carolina and Performance Based Regulation	)	**PUBLIC STAFF –**
	)	**NORTH CAROLINA**
	)	**UTILITIES COMMISSION**

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Q. Please state your name, business address, and present position.

A. My name is John W. Chiles. My business address is 1850 Parkway Place SE, Suite 800, Marietta, Georgia 30067. I am a Principal in the Transmission Services group within GDS Associates, Inc.

Q. Briefly state your qualifications and duties.

A. My qualifications and duties are attached as Appendix A.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to set forth the Public Staff's findings and recommendations resulting from our examination of the Application of Duke Energy Carolinas, LLC (DEC or the Company) filed in Docket No. E-7, Sub 1276 on January 19, 2023, (Application) for the test year ended December 31, 2021 (Test Year).

Q. Briefly explain the scope of your investigation.

A. My investigation is focused on the need and costs associated with the Company's Application and May 19, 2023 Supplemental Filing for the Transmission Multi-Year Rate Plan (MYRP) for the 2023-2026 rate period.

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Q. How is your testimony organized?

A. My testimony is organized as follows:

I. General Themes of DEC MYRP Evaluation
II. Proposed Adjustments to the DEC MYRP
III. Breaker Projects Proposed for Adjustment
IV. Capacity and Customer Planning Projects Proposed for Adjustment
V. System Intelligence Projects
VI. Transmission Line Hardening and Resilience Projects
VII. Recommendations

Q. Are you providing any exhibits with your testimony?

A. Yes. I am including one exhibit, described below:

- Chiles Exhibit 1 - Summary of Recommended Adjustments

I. <u>General Themes of DEC MYRP Evaluation</u>

Q. Are there some general themes that you have noticed in your review of the DEC Transmission MYRP?

A. Yes. During my review of the MYRP transmission projects, I noticed some recurring challenges and issues when attempting to validate the reasonableness of the Company's MYRP proposal, particularly regarding inconsistencies in responses between the DEP proceeding and the DEC proceeding. After working through the data requests with the Company in the DEP proceeding, I expected the

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same questions would produce similar responses. However, this was not the case. Inconsistencies in data responses (e.g., line loading information, outage impacts like number of impacted customers, etc.) resulted in needing even more technical meetings with the Company, which raised more questions that delayed our analysis. The challenges and issues I experienced generally dealt with topics such as project justification and alternatives, and project cost estimation.

Q. What do you mean by the term "Project Justification?"

A. When I speak of "project justification," I am speaking of how the Company evaluates and determines the need and timing for certain projects. This is different than having the necessary documentation for a project, like failure to provide a project coversheet. My focus is on how the Company conducted its technical assessment of system performance, how the Company evaluated system performance using Company criteria, and how the Company determined that the type and timing of proposed projects aligned with the Company system performance tests and Company reliability criteria. Part of my evaluation considered both the initial need (i.e., what triggered the project) of the project and the timing (i.e., when the Company needs to complete the project to resolve the issue that caused the need) of the Company's projected placed-in-service date of the project. Certain project types have different justifications, and the Company

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does not appear to have robust criteria for determining the need for projects.

Q. Please explain.

A. The Company appears to examine several factors when making decisions on what projects to advance in its planning processes. However, there are areas where the Company does not have specific criteria to determine the priority of projects or a definitive date of when a project must be completed.

Q. In addition to the Company's Initial Application, Supplemental Updates, and responses to discovery requests, has DEC provided other avenues of communication with the Public Staff to discuss the MYRP?

A. Yes, DEC technical staff and legal counsel have participated in a series of three meetings with members of the Public Staff and GDS to discuss the details of the Transmission MYRP ("Technical Meetings"). These Technical Meetings have allowed for technical discussions regarding project need identification, alternate solutions, project management, and cost estimation. The meetings were similar in scope to the Technical Meetings referenced in my pre-filed testimony in Docket No. E-2, Sub 1300 (DEP MYRP). Responses given in some of the Technical Meetings resulted in additional

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discovery, which added to my conclusions regarding certain projects in the assessment of the MYRP.

Q. Can you provide an example of a specific program where DEC does not have robust criteria for evaluation?

A. Yes, DEC has a strategy to rebuild its 44 kV facilities to 100 kV standards, which includes raising conductor height, installing new conductors, and replacing insulators so that these facilities can operate at 100 kV in the future. DEC has communicated to the Public Staff in various technical meetings that the reasons for this program are the age of facilities, historical outage performance, and taking preventative measures to harden these facilities for resilience purposes. In preparation for some of the technical meetings with DEC staff, I asked about outage history and number of impacted customers. In several examples, the outage frequency was six outages over a four-year period (2019-2022), with the Campobello 44 kV facility having 16 outages over that same time period. When asked if DEC had specific triggering criteria for a number of outages that it deemed unacceptable, Company representatives stated that there are no specific outage frequency criteria that flag a facility for needing system improvements. When asked about how the Company calculates risk in various technical meetings, DEC staff mentioned that risk includes factors such as outage frequency, outage duration, and customer impact. When pressed further in the

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meeting on any criteria for how many outages constitute a decision point for project upgrades, DEC stated they do not have a set criteria. I interpreted that answer to mean that DEC does not calculate any outage frequency metrics that allow staff to make any type of determination on the criticality of need of one project when compared to other projects.

Q. How does DEC categorize the various project types in its Transmission MYRP?

A. DEC classifies projects into several categories, as identified in Maley Exhibit 4. These project categories include: System Intelligence; Transmission Line Hardening and Resiliency; Substation Hardening and Resiliency; Transmission Vegetation Management; Breaker Upgrades; Transformers Upgrades; and Transmission Capacity and Customer Planning.

Q. You mentioned risks, including outages, as one factor. Are these the only criteria the Company uses?

A. No. DEC mentions things like criticality of load (e.g., hospitals and emergency services), but there are many other factors that can and should be considered, including age and condition of the facility, number of customers impacted, and project constructability.

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Q. Regarding project justification for MYRP project approval, should DEC examine project alternatives to resolve an identified issue when considering solutions?

A. Yes, it should. In the NERC Transmission Planning (TPL) standards, Transmission Providers are required to develop mitigation plans to address voltage, thermal, and stability issues revealed through their assessments. Mitigation plans are not limited to the construction of new facilities. As an alternative to the construction of new facilities, acceptable mitigation plans can include upgrades of existing facilities, non-wires alternatives, and operational guidelines. An Operating Guide is an action manually or automatically taken by the Balancing Authority Operator to alleviate thermal loading, voltage deviations, and stability issues in real-time. Transmission Planners can work with their operational counterparts to develop Operating Guides that are effective in mitigating a condition shown in TPL Assessments. I do not have an exhaustive list of the project alternatives considered by DEC, but one available tool the Company has referenced is the use of Operating Guides and Remedial Action Schemes (RAS) in their NERC TPL Assessments and subsequent project approval processes.

Q. In general, what is the purpose of an Operating Guide?

A. An Operating Guide is a pre-approved, operator-initiated sequence of steps designed to mitigate a system condition that results in thermal overloads, voltage violations, or stability violations that exceed the Company's NERC TPL criteria. Operating Guides can be used as temporary fixes until facilities can be constructed, or they can be put in place in lieu of a capital project until the Operating Guide ceases to be effective. They can also be used in cases where the issue is a low-frequency, low-impact occurrence.

Q. What is the difference between an Operating Guide and a Remedial Action Scheme (RAS)?

A. Remedial Action Schemes are a subset of Operating Guides. The difference is that the RAS is an automatic response to a grid condition while the Operating Guide is usually an operator-initiated event.

Q. Throughout the Company's TPL Assessments and MYRP justifications, DEC has proposed the use of RASs to address some NERC TPL violations. Are RASs an acceptable mitigation for NERC TPL violations?

A. Yes. Mitigation plans that utilize RASs are valid responses to certain conditions. NERC has accepted the use of an Operating Guide or an RAS as a valid mitigation plan for resolution of NERC TPL violations.

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Q. What RASs have been proposed as part of the Transmission MYRP?

A. There are two RASs proposed in the Transmission MYRP. They are for the Bethania lines and the Kennedy lines. This is not an unreasonable number of automatically implemented actions for a system the size of DEC.

Q. What is the purpose of the RAS for the Bethania Lines?

A. The Bethania Lines' RAS is designed to address multiple issues. The RAS will open two separate breakers in case of an overload. The RAS opens the Sherwood – White 100 kV line at the Shattalon switching station, along with opening the Frontage – Black 100 kV line – at the Shattalon switching station.

Q. Is there a transmission facility construction project that is planned to displace the use of the Bethania Lines RAS?

A. The Company has not indicated that there is a plan to replace the RAS with an MYRP project. In a Public Staff/DEC Technical Meeting on June 5, 2023 (June 5 Meeting), the Company did indicate that RASs are tools that can be used to displace MYRP projects.

Q. What is the purpose of the RAS for the Kennedy Ties?

A. According to the Company, this RAS addresses a thermal loading problem that could occur on the double-circuit Kennedy line. In the June 5 Meeting, the Company indicated that the Kennedy Ties' RAS

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exists because there is a construction project that cannot be completed by the need date, so the RAS is a stopgap measure until the facility can be constructed.

Q. If the Kennedy RAS is still effective, why is there a need for the construction project?

A. Since DEC developed the RAS to be effective and is trusting in that effectiveness to solve issues until the proposed construction project is completed, there is no reason to believe that the construction project cannot be delayed until after the end of the MYRP window.

Q. Does DEC have any other RASs in use on its system?

A. Yes, the Company stated in the June 5 Technical Meeting that it has four RASs in place. Two of those schemes are used to drop load and two drop generation.

Q. What factors go into determining that an RAS is preferrable to a transmission construction project?

A. Based on multiple technical meetings with the Company, it is my understanding that DEC considers the likelihood of an event and the number of impacted customers, among other factors, none of which are clear or were discussed in detail in the technical meetings.

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Q. Can an Operating Guide be a permanent solution for an identified constraint on the transmission system?

A. Yes. If an Operating Guide continues to be effective in addressing the identified constraint, system reliability is not unduly affected, and the Operating Guide continues to be a viable, economic solution, then it can be a permanent solution. Operating guides can also be used to delay a project to take advantage of the time value of money by delaying expenditures to future years. DEC tends to use Operating Guides as a temporary solution if a permanent construction project cannot be put in place in time to address a need. There are other utilities in the U.S. with longstanding Operating Guides in place because the cost of the Operating Guide is a less expensive solution than the capital project needed to resolve the issue at hand.

Q. Are you recommending that DEC take a more aggressive position toward the use of Operating Guides as a non-wires solution for some low-probability, low customer impact conditions?

A. No, and I am not taking a position as to how the Company is currently implementing its Operating Guides or non-wires solutions. However, based on my review of the information provided by the Company in this Application as well as discovery and technical meetings, I recommend the Company consider its criteria for what constitutes a low-risk, low-impact problem and whether an Operating Guide is a feasible option for those situations. My overarching concern is that there are viable solutions at the Company's disposal that are not being used to the benefit of ratepayers, and that more expensive solutions may have been proposed in this MYRP filing that could be deferred and reevaluated at a later time.

Q. Are the project cost estimates in the MYRP consistently calculated with the same level of rigor?

A. No. The Company has communicated that projects advance through several "stage gates" from conceptual design to detailed construction. At each stage gate, the quality of the estimate should improve because more detailed engineering is being completed, and the cost of materials, equipment, and labor should be better known. The proposed MYRP projects are not all at the same stage in terms of project estimation and approval process, so the estimates for the various transmission MYRP projects do not necessarily reflect the same level of rigor and certainty. The estimates for projects with later in-service dates and short lead times may have a level of accuracy that is within the Class 5 estimate range of +100%/-50%. Projects that require long lead time items such as transformers or projects that are due to be completed in the Rate Year 1 window should have estimates with a greater level of certainty.

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Q. Does the differing basis for cost estimation create any potential for inaccuracies in the cost-benefit value of particular projects?

A. Yes, it does. DEC provided benefit-to-cost ratios for the different project portfolios and also performed a sensitivity analysis for the portfolios looking at the impact of increasing capital costs.[1] Including projects with very little margin for cost deviations in the benefit-to-cost calculation and performing a sensitivity analysis beyond the quality of the estimate can mask individual projects that have marginal economic benefit. As projects move through the stage gate estimation and approval process, the projects' costs should become clearer. Equipment costs should reflect a greater level of site and project specific engineering, the cost of long-lead-time items should be better known as items are procured, and labor estimates should have more certainty as scope is tightened. A Class 5 estimate has a larger margin for error since the project is in the initial scoping phase, while a project estimate that has greater engineering, scope, materials, and labor specificity, such as a Class 3 estimate, should not incur a 100% increase in cost as is possible with a Class 5 estimate.

[1] Initial Filing, DEC witness Maley Testimony, Exhibit 3: Cost Benefit Analysis, at 8, 15, 23, 31, 38 and 45.

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Q. Do you have any recommendations for improvements to the DEC project cost estimation process?

A. My recommendation is that each project be evaluated for its own benefit-to-cost ratio so that each project can be demonstrated to be economically viable or not. If project efficiencies exist between projects, the economics will be improved. If no project efficiencies exist, then ratepayers will still receive a positive benefit from project inclusion.

II. <u>Impact of Moore County Outages on MYRP</u>

Q. In the May 31, 2023 Technical Meeting, DEC discussed its plans to accelerate a series of Transmission Substation Security projects. Did the Company give a reason for these projects?

A. Yes. In response to discovery, DEC stated that the Company reevaluated its substation physical security practices following the Moore County Transmission grid infrastructure attacks in December 2022.

Q. Are you opposed to the Company improving the physical security of its critical substations?

A. No. I am supportive of the protection of critical infrastructure if done in a systematic and prudent fashion. However, I have some concerns as to whether an accelerated schedule is appropriate for project inclusion in the MYRP. Project acceleration, regardless of whether

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the projects are Transmission Substation Security projects, results in ratepayers bearing the full financial risk versus the Company, should the project actually fall beyond Rate Year 3.

III. Breaker Projects Proposed for Adjustment

Q. What portion of the Transmission MYRP is associated with Breaker Projects?

A. Breaker Projects make up 18.17% of the total cost of the Transmission MYRP.

Q. Are you proposing any adjustments to the list of Breaker Projects in the May 19 Supplemental MYRP filing?

A. There are two Breaker Projects that I am proposing be adjusted:

- Cliffside Switching Station TOIL[2] Breaker Replacement.
- Great Falls Switching Station TOIL Breaker Replacement.

Q. Please describe the Cliffside Switching Station TOIL Breaker Replacement Project.

A. The Cliffside TOIL Breaker Replacement Project[3] (W170159) is projected by the Company to be placed in service in August 2025, with an estimated cost of $11 million. In its Initial Filing, DEC

[2] TOIL = Transmission Oil-Filled.

[3] Maley Supplemental Testimony, Exhibit 2, at 1.

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estimated the price of this project was $10.9 million with an in-service date of May 2025.

Q. What changes to this project are you recommending?

A. I am recommending that the Cliffside TOIL Breaker Replacement Project be removed from the DEC Transmission MYRP. The Company has failed to provide adequate detail, including age and condition of equipment, test results showing breaker failures, etc., to justify the need for this project in the MYRP. I cannot locate where the Company provided any support for this project in its supporting workpapers or in specific discovery.

Q. What system savings will result from the removal of this project?

A. The removal of the Cliffside TOIL Breaker Replacement project will result in system savings of approximately $11 million.

Q. Please describe the Great Falls Switching Station TOIL Breaker Replacement project.

A. The Great Falls Switching Station had 25 TOIL breakers that were identified for replacement. Five of those breakers have already been addressed, leaving 20 breakers to be replaced during the MYRP period. This project is broken into three phases, with Phase 1 being completed by December 2024. Phase 2 is expected to be completed by December 2025, and Phase 3 is due to be completed by October 2026.

Q. Please describe the scope of work for Phase 1.

A. The initial cost for Phase 1 of this project was estimated at approximately $6.3 million (Class 5 Estimate). During the time between the Initial Filing and the May 19 Supplemental Filing, the Company increased the project cost by around $4.2 million to a total cost of approximately $10.5 million. witness Maley states that the reason for the cost increase is due to detailed engineering being completed on the project as it proceeds through the stage gate process with the current cost based on the design package release.[4] witness Maley also notes that the scope of the project has remained unchanged since the Initial Filing. This is illustrative of my concern that projects are being approved prematurely and requests for cost recovery are occurring before definitive cost estimates have been established (i.e., only projects with a Class 3 or better estimate have more satisfactory certainty for DEC to seek cost recovery).

[4] Maley Supplemental Filing, Exhibit 3, Page 2.

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Q. Have costs for Phases 2 and 3 of the Great Falls Switching Station TOIL Breaker Replacement project experienced the same level of cost adjustments as Phase 1?

A. No. The Phase 2 portion of the project costs decreased by $189,660, from $7,228,336 to $7,038,676. Phase 3 costs decreased by $139,348 from $4,787,124 to $4,647,777. In both cases, the reasons for the change in costs were the same as provided for Phase 1; therefore, it is assumed that these cost refinements are the result of stage gate progression.

Q. What is your recommendation regarding the Great Falls Switching Station TOIL Breaker Replacement project?

A. I am recommending that the Company replace no more than five of these breakers during the current MYRP because the Company has not provided any empirical data related to individual breaker performance or test data which indicates these breakers need to be replaced during this MYRP cycle.

Q. What are the savings to be realized by ratepayers if the Company agrees to your recommendation regarding the Great Falls Switching Station?

A. The estimated savings would be 75% of the total project cost, or $13,744,730.

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Q. Are there any new breaker projects that the Company has proposed in the May 19 Supplemental Transmission MYRP that you are recommending being excluded?

A. Yes. There are ten new projects totaling approximately $26.4 million[5] for which the Company did not provide adequate documentation or project justification. If the Company provided no technical support for a project, I made a recommendation that the project be removed as reflected in witness Metz's testimony. Areas for breaker replacement projects where DEC should provide additional information to provide a technical basis for breaker replacements include:

- Age and ampacity of breaker to be replaced;
- Last five years of maintenance records;
- Results of any performance tests which show degradation in performance;
- Ampacity of new breaker to be installed; and
- Any generator interconnection study that identifies the need for the breaker to be replaced due to increased short circuit current from an interconnection request.

I request DEC to address for each of the Breaker Replacement projects included in the Initial Application and May 19 Supplemental

[5] Aggregate total includes some projects for which cost recovery was not sought in the MYRP.

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filing in rebuttal testimony by providing project details and justifications.

Q. What is the total ratepayer savings associated with the Breaker Replacements you are proposing be eliminated from cost recovery in this case?

A. The total ratepayer savings associated with the Breaker Replacements is approximately $51.2 million. The table below shows the breakdown of savings by project:

Table 1: Recommended Breaker Replacement Projects

Breaker Projects	
Name	System Adjustment
Cliffside TOIL Breaker Replacement	$ (11,053,432)
Great Falls Switching Station TOIL Breaker Replacement	$ (13,744,730)
Blue Ridge EC Del 14 TOIL Breaker Replacement	$ (1,055,118)
Broad River EC Del 2 TOIL Breaker Replacement	$ (874,381)
Burlington Main TOIL Breaker Replacement	$ (5,069,639)
Crest Street Retail TOIL Breaker Replacement	$ (4,300,817)
Duke University Station 1 TOIL Breaker Replacement	$ (3,241,423)
Eastgate TOIL Breaker Replacement	$ (3,910,298)
EnergyUnited EMC Del 23 TOIL Breaker Replacement	$ (1,832,525)
Kivett Drive Retail TOIL Breaker Replacement	$ (1,047,087)
Mt. Tabor TOIL Breaker Replacement	$ (3,868,213)
Toast Retail TOIL Breaker Replacement	$ (1,155,856)
Total Breaker Replacement Projects	**$ (51,153,519)**

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IV. Capacity and Customer Planning Projects Proposed for Adjustment

Q. What portion of the Transmission MYRP is associated with Capacity and Customer Planning Projects?

A. Capacity and Customer Planning Projects make up 32.52% of MYRP capital costs.

Q. What is the total impact of your recommendations for Capacity and Customer Planning project adjustments to the Transmission MYRP?

A. The total impact of the proposed adjustments is approximately $81.5 million as shown in Table 2 below.

Table 2: Recommended Capacity and Customer Planning Project Adjustments

Capacity and Customer Planning Projects	
Name	System Adjustment
Eno Tie	$ (15,946,776)
North Greenville Tie Bus Junction Breaker (BJB) Replacement	$ (22,564,879)
Bethania and Shattalon Line Equipment Uprate	$ (2,885,375)
Shady Grove Tie	$ (13,217,416)
Page and Guilford 100 kV Line Rebuild	$ (21,639,675)
Stamey Tie	$ (4,167,472)
Boyds to Trinity Ridge	$ (1,088,624)
Total Capacity and Customer Planning Projects	**$ (81,509,611)**

Q. Do you have any initial comments on the technical aspects of the DEC transmission planning process that formed the basis for the Capacity and Customer Planning projects in the MYRP?

A. In my review of the DEC power flow models and study results, I can say that the models used by the Company for its TPL Assessments were consistent with respect to load modeling, transmission facility modeling, and generation assumptions. With the power flow models and associated modeling files provided by the Company in discovery, my team was able to verify the results of the various NERC TPL assessments.

Q. Please describe the purpose of the Eno Tie 230 kV Bus Breakers project.

A. The purpose of the Eno Tie project is to address a NERC TPL violation. The project is a Rate Year 3 MYRP project.

Q. What is the in-service date for this project?

A. The in-service date has moved one month from July 2026 (Application) to August 2026 (Supplemental Update).

Q. How have the costs for this project changed from the Application to the May 19 Supplemental Update?

A. The cost of the project has increased by $146,394 from $15,799,776 to $15,946,170.

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Q. When was the need for the Eno Tie project initially identified?

A. The NERC violation that is being used to support the justification for this project first occurred in the DEC 2019 NERC TPL Assessment. The need for this project was not demonstrated in the 2021 or 2022 NERC TPL Assessments.

Q. Does the Company have a mitigation plan in place to address the violation before this project is completed?

A. Yes. In the June 5 Technical Meeting, DEC staff communicated that there is an existing Operating Guide that is available for operator use until the project is completed.

Q. Has the Company provided any information indicating that the Operating Guide currently being used to address the Eno Tie need is no longer effective?

A. No, they have not. The justification for the use of the Operating Guide is to have a temporary fix for the issue until the Eno Tie 230 kV Bus Breaker project is completed.

Q. If the Operating Guide is still effective and the Company is willing to trust that it will be effective through Year 2 of the MYRP, is there a definite need for the Eno Tie project?

A. I do not believe that the Eno Tie 230 kV Bus Breaker project is necessary as part of the Transmission MYRP due to the effectiveness of the Operating Guide.

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Q. What is your recommendation regarding the Eno Tie 230 kV Bus Breaker Replacement project?

A. I recommend that the Company defer the construction of this project outside the Transmission MYRP window until it identifies that the current Operating Guide is no longer effective or until the frequency of violations significantly increases.

Q. What is the financial impact of your recommendation?

A. The deferral of the Eno Tie 230 kV Bus Breaker project will result in a savings of approximately $15.9 million in this MYRP cycle.

Q. Please describe the purpose of the North Greenville Bus Junction Breaker (BJB) replacement project.

A. The purpose of the North Greenville BJB project is to address a NERC TPL violation that first occurred in the DEC 2017 NERC TPL Assessment. This project is proposed to be completed in three phases. Phase 1 was due to be completed in April of 2024. Phases 2 and 3 were due to be completed in April and May of 2025, respectively. In the May 19 Supplemental Update, all three phases are now due to be completed in April 2026, signifying a significant shift in the need and timing implementation of the proposed project.

Q. Has DEC explained why this issue has not been seen in other TPL Assessments?

A. In the June 5 Technical Meeting, DEC staff shared that an Operating Guide was developed to open the bus tie breaker. They explained that this was the reason why the problem has not shown up in other TPL Assessments.

Q. Has DEC provided any information indicating that the Operating Guide currently being used to address the North Greenville BJB replacement need is no longer effective?

A. No, they have not. If the Company does have data that will demonstrate that the Operating Guide is no longer effective, or when it will be ineffective, I would ask that they provide that information in rebuttal.

Q. If the Operating Guide is still effective, is there a definite need for the North Greenville BJB replacement project?

A. I do not believe that the North Greenville BJB replacement project is necessary as part of the Transmission MYRP. Until DEC can demonstrate that the Operating Guide will no longer be effective, or the frequency or impact of the violation significantly changes, there is not a technical rationale for construction of the project at this time.

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Q. What is your recommendation regarding the North Greenville BJB replacement project?

A. I recommend that the Company defer the construction of this project outside the Transmission MYRP window until the current Operating Guide is no longer effective or until the frequency of violations significantly increases.

Q. What is the financial impact of your recommendation?

A. Removing the North Greenville BJB project from the MYRP will result in a system savings of $22.6 million.

Q. The MYRP includes a proposed project for a Bethania and Shattalon line equipment upgrade. Additionally, there is a project called "Bethania Lines – RAS." Are these projects related?

A. I believe they are related and are redundant. The Bethania and Shattalon Line Upgrade project was added to the MYRP in the May 19 Supplemental Filing. This project was moved to April 2024 due to construction and outage coordination.

The RAS will open two lines at the Shattalon switching station in order to address an overload on the Bethania lines. The use of the RAS moved from April 2024 to December 2024. In response to discovery, DEC staff stated that **[BEGIN CONFIDENTIAL]** [redacted]

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[redacted] **[END CONFIDENTIAL]** Therefore, I do not see a need for multiple solutions to solve the same problem. Since the issue was first identified in the Company's 2017 TPL Assessment, the use of the Operating Guide has been effective and is expected to be effective into the future. When asked in discovery to provide the change file for this project to include this in the power flow models, DEC only provided the line reconductor project and not the line equipment upgrade project.

Q. If the RAS is an effective short-term solution, do you see a need for both projects?

A. Not at this time. If the RAS is an effective solution and can be implemented at a lower cost than the construction project, then my recommendation would be to use the RAS until planning studies show the RAS is no longer effective. The Company has stated in technical meetings with me and the Public Staff that RAS is a tool for the evaluation of the need for MYRP projects. In addition, the DEC TPL assessment indicates that DEC plans to reconductor both lines in 2034. I disagree with the inclusion of the line upgrade project in

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2024 when the need has been shown by the Company's own analysis to be for ten years later. Given these long-term plans and the effectiveness of RAS in mitigating the issue, I do not see a need for the project. If DEC considers the RAS and the equipment upgrade to be addressing different issues, I invite them to explain all differences in rebuttal.

Q. What is the purpose and justification for the Shady Grove Tie project?

A. DEC proposed this project to mitigate overloads on the Sevier BL 100 kV line and the Perry BL 100 kV line in response to a NERC TPL violation in the 2022 NERC TPL Assessment. Furthermore, the Perry BL 100 kV line only experienced an overload due to the P5 contingency[6] at Shady Grove once in the 2024 model of the 2022 TPL Assessment, and other contingencies that caused overloads on the Perry line have Operating Guides applied.

[6] P5 is defined as "Multiple Contingency," which is a "Fault plus non-redundant component of a Protection System failure to operate." The event is described as a "Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Station." TPL-001-5 – Transmission System Planning Performance Requirements at 23. https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

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Q. Based on your analysis, should this project be included in the MYRP?

A. This project should not be included in the Transmission MYRP. DEC has also included a Sevier 100kV - Line Rebuild in the MYRP (May 2026) that was identified to mitigate an overload on the Sevier BL 100 kV line. The DEC TPL assessment provided an RAS solution for the overload on the Perry BL 100 kV line. Given that the Sevier 100 kV Line Rebuild projects and the RAS solution both appear to address the situation identified by DEC that serves as the basis for the Shady Grove BJB Project, I do not see a need for this duplicative project. If DEC considers the RAS and the equipment upgrade to be addressing different issues, I invite them to explain all differences in rebuttal.

Q. The Company is proposing to rebuild the Page and Guilford 100 kV line in the MYRP. Please describe this project, the cost, and the justification.

A. The most recent information provided on the Page and Guilford 100 kV project (Supplemental Update) is that the scope is for the reconductor of 7.28 miles of line at an estimated cost of $21.6 million, whereas the initial Class 5 estimate (Application) was for only two miles of reconductoring costing approximately $4.4 million. The project is proposed to address a NERC TPL violation.

Q. Does the Company have any alternatives for addressing the project need apart from a construction project?

A. Yes, it does. The current solution from the Company's NERC TPL Assessments is an Operating Guide and an RAS.[7] The Operating Guide and RAS continue to be effective, so I only see a need for an immediate expenditure once long-term use of the Operating Guide ceases to be effective. When asked about the effectiveness of the Operating Guide and RAS for this project at one of the Technical Meetings, DEC staff did not indicate that the Operating Guide and RAS are ineffective. Therefore, I am recommending removal of this project from the MYRP.

Q. Should the Stamey Tie Redundant Bus Protection project be included in the MYRP window?

A. No. DEC's TPL Assessment does not support a need for this $4.2 million project within the MYRP window. DEC did not identify the issue until its 2030 power flow model. The TPL assessment for DEC 2022 has identified one instance of an overload at Stamey due to a single P5 contingency in the 2030 power flow model. Although the Silas Line upgrade is not part of the MYRP project, it appears to have addressed most of the issues identified that the Stamey project was

[7] DEC's 2022 TPL Assessment shows: "Gboro Mn RAS is in service, and will shed the load at Greensboro Main upon detection of overloaded Page and/or Guilford circuits. Reduces loading to 96% of 12-hr rating."

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supposed to correct.[8] Given the lack of an immediate need and the fact that this is a substation-related project, I do not agree with the decision to include it in the Transmission MYRP. I am recommending that the Stamey project be removed from this MYRP until additional contingency analysis reveals a continuing need.

Q. The Company included the Boyds to Trinity Ridge project in the MYRP. What is your view of this project?

A. The Boyds to Trinity project was moved into the MYRP window in 2024 in the May 19 Supplemental Update,[9] but the reason given was right-of-way and access issues.[10] I recommend removing this project because of a lack of support and uncertainty regarding why right-of-way would cause a need for this project. This project should be excluded from the MYRP until the Company provides adequate justification for the need.

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[8] DEC 2021 TPL assessment shows: "Line Upgrade Project: Silas Lines upgrade project has been submitted (W200094)."

[9] Maley Direct Supplemental Update Exhibit 3, Page 2 of 10.

[10] Access issues refers to the ability to get to the transmission facility for maintenance purposes. Access may be limited due to landowner construction abutting or crossing the right-of-way.

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V. System Intelligence Projects

Q. What percentage of the Transmission MYRP expenditures are in the System Intelligence category?

A. According to the data provided by witness Maley in the May 19 Supplemental MYRP filing, the System Intelligence Projects category accounts for 24.14% of all Transmission MYRP expenditures.

Q. What adjustments are you recommending to the System Intelligence category?

A. I am recommending adjustments to two condition-based monitoring projects and to the new relay upgrade projects added in the May 19 Supplemental Update.

Q. Please describe the adjustments you are recommending to the condition-based monitoring projects.

A. I am recommending that the Carolina West condition-based monitoring project be removed. This is a new project from the May 19 Supplemental Update. When compared to other condition-based monitoring projects in the MYRP, the Carolina West project is one of the only outliers and the project cost is nine times the cost of any other condition-based monitoring project. Due to the lack of scope details that would explain this cost difference, I am recommending the disallowance of the entire $4,551,831.

In addition, I am recommending the disallowance of $4,000,000 from the Transformer Condition-Based Monitoring project. The costs for this project have increased five-fold since the Initial Filing, with no additional justification provided. The disallowance brings the cost in line with other MYRP condition-based monitoring projects.

Q. What relay upgrade projects are you recommending be excluded from the Transmission MYRP?

A. I am recommending that the relay upgrade projects filed in the Company's May 19 Supplemental Update be removed because the Company has not provided any engineering justification for any of these new relay upgrade projects. There is no technical documentation or studies showing why these projects are needed, such as age and condition of relays, number of mis-operations, or if any of the projects are assignable to generation interconnection customers resulting from interconnection requests and not assignable to load. The addition of these projects has raised the cost of this project portfolio from $19,508,487 to $41,185,155. These projects include:

- Albemarle Switching Station ($260,414)
- Beech Street Retail ($1,063,021)
- Campobello Tie ($1,030,270)
- Catawba NC Busline ($2,712,738)

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- Concord Main ($909,540)
- Depot Street Retail ($2,620,863)
- Dilworth ($361,060)
- Draper Retail ($981,077)
- Duke Univ. Station 1 & 2 ($3,140,636)
- East Spencer ($774,326)
- First Quality Tissue ($521,712)
- Highland Retail ($526,996)
- McAddenville Retail ($627,978)
- North Kannapolis Retail ($3,562,114)
- Robert Bosch ($603,321)
- Seneca Place ($608,938)
- Shuman Avenue ($681,416)
- West Norwood Retail ($690,328)

Q. What is the total impact of your adjustments to the System Intelligence category?

A. Table 3 below shows the impact of my adjustments.

Table 3. Recommended Adjustments to System Intelligence Project

System Intelligence Projects	
Name	System Adjustment
Carolina West Condition-Based Monitoring	$ (4,551,831)
Transformer Condition-Based Monitoring	$ (4,000,000)
Relay Upgrades (New May 19 Supplemental MYRP Projects)	$ (21,676,758)
Total System Intelligence Projects	**$ (30,228,589)**

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VI. Transmission Line Hardening and Resilience Projects

Q. What percentage of the Transmission MYRP expenditures are in the Transmission Line Hardening and Resilience Projects category?

A. According to the data provided by witness Maley in the May 19 Supplemental MYRP filing, the Transmission Line Hardening and Resilience Projects category accounts for 24.14% of the Transmission MYRP.

Q. Is there a particular group of projects in this category that are of general concern to you?

A. Yes. DEC has proposed several 44 kV to 100 kV rebuild projects that do not have clearly defined reasoning for inclusion in the Transmission MYRP. I am not generally opposed to voltage uprate projects, but I believe that there needs to be either a TPL violation issue, a significant outage history, or the addition of new load that requires a level of service that cannot be supported by the lower voltage facilities.

Q. Does the Company have a strategic goal of upgrading the 44 kV system?

A. Yes. The Company has communicated that one of their goals is to upgrade the 44 kV system by rebuilding facilities to 100 kV specifications and operating those facilities at 44 kV until the voltage conversion is complete.

Q. What is the driver for this project set?

A. This is a long-term Company strategy to replace these facilities. The Company notes that the age and condition of the 44 kV system is the primary driver. Some of these lines are well beyond their useful life (70+ years) per the June 5 Technical Meeting.

Q. What 44 kV facilities are currently being contemplated for conversion in the Transmission MYRP?

A. The following Transmission MYRP projects relate to the 44 kV conversion program:

- Esto – Pickens 100 kV Rebuild
- JP Stevens 44 kV to 100 kV Rebuild
- Sawmill 1 & 2 44 kV to 100 kV Rebuild
- Sigsbee A & B 44 kV to 100 kV Rebuild
- Silas 44 kV to 100 kV Rebuild

Q. Please describe the Esto – Pickens Rebuild project and the reasons given by the Company to support this project need.

A. The Company's plan is to replace all the existing wood poles with steel poles and to string new conductors to accommodate 100 kV standards but continue operating at 44 kV.

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Q. What is the historical outage frequency on the Esto - Pickens 44 kV circuits?

A. From 2019 to 2022, six outage events were recorded.

Q. Are you recommending inclusion of this project in the Transmission MYRP?

A. No. I am recommending the exclusion of the Esto - Pickens 44 kV conversion project from the MYRP. There is not a demonstrated need for the 44 kV conversion consistent with NERC TPL Standards. Although the Company stated that there were six outages on this facility from 2019 to 2022, the Company has also stated that there is no defined standard for the number of outages that are permissible on a facility before it is considered for upgrade.

Q. Please describe the JP Stevens 44 kV Rebuild Project.

A. DEC is proposing that the JP Stevens 44 kV line be rebuilt to 100 kV standards. This includes replacement of wood poles with steel poles, raising pole heights for wire sag[11] purposes, replacement of insulators, and increasing the spacing between line phases.

[11] Wire sag needs to be addressed because the National Electric Code requires minimum clearance to be maintained or conductor under certain ambient conditions.

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Q. What justification has DEC given for this project?

A. Based on multiple technical meetings with the Company, it is my understanding that the reason for this project is degradation of the facilities. The Company provided no outage history data as part of their MYRP to justify the project.

Q. The in-service date given in the Initial Application and the May 19 Supplemental Update for this project is May 2025. How was this date derived?

A. DEC has stated in multiple technical meetings that the in-service date of a given project is determined based on where the project falls within the prioritization process. The DEC team communicated in the June 5 Technical Meeting a general observation that factors such as drivers, needs, budget, resources, and SME opinion go into determining which year a project will be planned to go into service. However, the Company has not supported their general claims on how those factors drove the decision to place this project in service in May 2025.

Q. Can you state affirmatively that the need for the JP Stevens 44 kV to 100 kV Line Rebuild lies within the MYRP window?

A. DEC has stated that they have a five-year plan for the 44 kV uprate projects. According to DEC, the projects included in the

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Transmission MYRP are the ones in the five-year plan that met the criteria for inclusion in the MYRP three-year window.

Q. Are there situations similar to JP Stevens 44 kV that should also be addressed?

A. Yes. The Sigsbee and Sawmill projects have a similar issue and should also be removed on the same basis as JP Stevens.

Q. Has DEC given a rationale for the use of a five-year plan for this 44 kV strategy?

A. No. The Company's reasoning for the five-year plan has not been addressed in the technical meetings between the Public Staff, GDS, and DEC. My concern with the 44 kV conversion projects is that there are no NERC TPL violations associated with these projects, and the outage information supplied by the Company on these projects does not seem to be a driver. The outage data shared by DEC show low levels of outages and do not demonstrate a degradation of performance that would warrant a rebuild of these facilities at this time.

Q. Were any 44 kV projects added to the MYRP in the May 19 Supplemental Filing?

A. Yes. The Company proposed two additional projects: the Belfast 44 kV and Rockford 44 kV line rebuilds. The Belfast line rebuild was supposed to be completed prior to the start of this MYRP cycle. From the Initial Filing to the May 19 Supplemental Filing, the Company determined that the start date for these projects should be moved into the MYRP cycle, with a November 2023 start date. No other technical justification or document has been provided to demonstrate the need for the Belfast project. For the reasons I stated earlier regarding the lack of a NERC TPL issue as a driver and a lack of outage history regarding these lines, I am recommending that these two projects be removed from the MYRP. Belfast and Rockford are examples of a 44 kV line rebuild project in the May 19 Supplemental Transmission MYRP where DEC has not provided any detail regarding line outage history, age of equipment, or TPL impacts. I encourage the Company to address the specific need and driver for these projects in rebuttal testimony.

Q. What is the total impact of your recommendations regarding Transmission Line Hardening & Resilience Projects?

A. The total impact of my recommendations is shown in Table 4 below.

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Table 4: Recommended Transmission Line Hardening & Resilience Projects Adjustments

Transmission Line Hardening and Resilience Projects	
Name	System Adjustment
Esto - Pickens Rebuild	$ (18,200,045)
JP Stevens Line Rebuild	$ (29,728,852)
Sawmill 1 & 2 Line Rebuilds	$ (28,849,806)
Sigsbee A & B Line Rebuilds	$ (26,094,270)
Belfast 44 kV Line Rebuild (New)	$ (13,945,930)
Rockford 44 kV Line Rebuild (New)	$ (11,299,594)
Total Transmission Line Hardening and Resilience Projects	**$ (128,118,917)**

VII. Recommendations

Q. Are you making any recommendations to the Commission?

A. Yes. I recommend that the Commission make the disallowances and adjustments I discussed above, which are due to the availability of lower cost alternatives, lack of project justification, adjustments to timing based on the Company's own analyses, and removal of new projects not fully vetted by the Company in the May 19 Supplemental MYRP Filing. Table 5 shows the total system savings that can be gained.

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Table 5: Summary of Recommended Adjustments to DEC MYRP

Project Type	Total Adjustments
Breakers	$ 51,153,519
Capacity and Customer Planning	$ 81,509,611
System Intelligence - Condition Based Monitoring	$ 8,551,831
System Intelligence - Relay Upgrades	$ 21,676,758
Transmission Line Hardening & Resilience	$ 128,118,917
Total Adjustments	**$ 291,010,636**

Q. Does this conclude your testimony?

A. Yes.

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QUALIFICATIONS AND EXPERIENCE

JOHN W. CHILES

I have over 35 years of electric utility and consulting experience. I provide regulatory and strategic support for generation and transmission cooperatives, municipal electric systems, independent generation developers, industrial consumers and state commissions regarding regional transmission organization energy markets, open access transmission issues, transmission planning and need certification, generation siting and interconnection, NERC compliance support and training, and stakeholder representation in RTO stakeholder forums. I hold a Bachelor of Science in Engineering degree from the University of South Florida.

My areas of expertise include the following activities:

Regional Transmission Organization Operations and Policy Support

- Market Integration Support for new entrants in California Independent System Operator (CAISO), SPP and MISO
- Market Analysis of Nodal Price Data
- Technical Support on RTO Settlements Issues

Energy Market Design

- Nodal Market Development (ERCOT)
- Resource Adequacy Market Development (PJM)
- Energy Imbalance Market Development (SPP, WECC)

Open Access Transmission Issues

- Loss Study Review and Support

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- Deliverability Analysis for Generation Assets
- Negotiation of Agreements for Transmission Service

Transmission System Modeling and Planning

- Power Flow Analysis
- Short Circuit Analysis
- Need Certification Technical Studies
- Review of Impact of Transmission Expansion Plans on Load and Generation

Production Cost Modeling and Simulation

- PROMOD Studies for Generation Margin Determination and Load Cost Analysis
- Assessment of Economic Transmission Projects
- Financial Transmission Rights Evaluation

Generation Interconnection Process Evaluation and Support

- Power Flow-Based Site Selection Analysis
- Technical Support for Review of Transmission Provider Studies
- Negotiation of Interconnection Service Agreements

NERC Compliance Activities

- TPL Assessments
- Development of Policies, Guidelines and Procedures
- Mock Audits and Gap Analysis
- Subject Matter Expert Training for TPL, FAC, and MOD Standards

Regulatory, Strategic and Stakeholder Support

- Stakeholder Representation at MISO, SPP, and ERCOT
- Technical and Regulatory Support for Clients at FERC and State Jurisdictions

I have filed expert witness testimony and participated in hearings at the Federal Energy Regulatory Commission (FERC) and at the Alaska, Arkansas, Mississippi, Texas, and Virginia State regulatory commissions.

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GDS ADJUSTMENTS - DEC MYRP

Project Type	Project Name
Breakers	Cliffside TOIL Breaker Replacement
Breakers	Great Falls Switching Station TOIL Breaker Replacement
Breakers	Blue Ridge EC Del 14 TOIL Breaker Replacement
Breakers	Broad River EC Del 2 TOIL Breaker Replacement
Breakers	Burlington Main TOIL Breaker Replacement
Breakers	Crest Street Retail TOIL Breaker Replacement
Breakers	Duke University Station 1 TOIL Breaker Replacement
Breakers	Eastgate TOIL Breaker Replacement
Breakers	EnergyUnited EMC Del 32 TOIL Breaker Replacement
Breakers	Kivett Drive Retail TOIL Breaker Replacement
Breakers	Mt. Tabor TOIL Breaker Replacement
Breakers	Toast Retail TOIL Breaker Replacement
Capacity and Customer Planning	Eno Tie
Capacity and Customer Planning	North Greenville Tie Bus Junction Breaker (BJB) Replacement
Capacity and Customer Planning	Bethania and Shattalon Line Equipment Uprate
Capacity and Customer Planning	Shady Grove Tie
Capacity and Customer Planning	Page and Guilford 100 kV Line Rebuild
Capacity and Customer Planning	Stamey Tie
Capacity and Customer Planning	Boyds to Trinity Ridge
System Intelligence - Condition Based Monitoring	Carolina West - Condition Based Monitoring
System Intelligence - Condition Based Monitoring	Transformer Condition Based Monitoring
System Intelligence - Relay Upgrades	Albemarle Switching Station
System Intelligence - Relay Upgrades	Beech Street Retail
System Intelligence - Relay Upgrades	Campobello Tie
System Intelligence - Relay Upgrades	CNS Busline
System Intelligence - Relay Upgrades	Concord Main
System Intelligence - Relay Upgrades	Depot Street Retail
System Intelligence - Relay Upgrades	Dilworth
System Intelligence - Relay Upgrades	Draper Retail
System Intelligence - Relay Upgrades	Duke University Station 1 & 2

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System Intelligence - Relay Upgrades	East Spencer
System Intelligence - Relay Upgrades	First Quality Tissue
System Intelligence - Relay Upgrades	Highland Retail
System Intelligence - Relay Upgrades	McAddenville Retail
System Intelligence - Relay Upgrades	North Kannapolis Retail
System Intelligence - Relay Upgrades	Robert Bosch
System Intelligence - Relay Upgrades	Seneca Place
System Intelligence - Relay Upgrades	Shuman Avenue
System Intelligence - Relay Upgrades	West Norwood Retail
Transmission Line Hardening & Resilience	Esto - Pickens 100 kV Rebuild
Transmission Line Hardening & Resilience	JP Stevens 44 kV to 100 kV Rebuild
Transmission Line Hardening & Resilience	Sawmill 1 & 2 44 kV to 100 kV Rebuild
Transmission Line Hardening & Resilience	Sigsbee A & B 44 kV to 100 kV Rebuild
Transmission Line Hardening & Resilience	Belfast 44 kV Line Rebuild
Transmission Line Hardening & Resilience	Rockford 44 kV Line Rebuild

Summary of Adjustments

Project Type
Breakers
Capacity and Customer Planning
System Intelligence - Condition Based Monitoring
System Intelligence - Relay Upgrades
Transmission Line Hardening & Resilience
Total Adjustments