August 26, 2024

Richard Wodyka
Administrative Consultant
Carolinas Transmission Planning Collaborative
VIA EMAIL: rich.wodyka@gmail.com

RE: Joint Comments on MVST Study Proposals

Dear Rich:

The Carolinas Clean Energy Business Association (CCEBA), Southern Environmental Law Center, Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association, Sierra Club, and the Southeastern Wind Coalition submit these comments in response to the Carolinas Transmission Planning Collaborative's (CTPC) draft 2024 Multi-Value Strategic Transmission (MVST) Study scope, as presented during the August 12, 2024 Transmission Advisory Group (TAG) Assumptions Meeting and distributed via email on August 16, 2024.

We appreciate the CTPC's effort to accommodate the scenarios submitted for consideration on June 28, 2024, and the opportunity to provide feedback on its proposed study scope. We also share the CTPC's desire to plan transmission expansion in an efficient, proactive, and cost-effective manner.

However, the CTPC's proposed approach to the first MVST study cycle would limit the value of the new MVST process as compared to the previous, siloed transmission planning process. In directing Duke to modify the CTPC, the North Carolina Utilities Commission (Commission) instructed the Company to "integrate transmission planning with resource planning to maintain the reliability of the electric system and to ensure a least cost path to compliance with" its carbon reduction mandates.[1] The CTPC's proposed approach would not abide by this directive, likely resulting in higher costs and lower reliability for customers. Fixable flaws in the proposed study scope include failing to utilize a nodal production cost model, employing static generation assumptions, and applying a short 10-year planning horizon, among other issues. To this end, we urge the CTPC to incorporate the following suggestions before finalizing its study scope.

[1] Order Adopting Initial Carbon Plan and Providing Further Direction for Future Planning, Docket No. E-100, Sub 179, at 121 (Dec. 31, 2022).

1. Nodal Production Cost Model

At the Assumptions Meeting, CTPC representatives suggested that instead of conducting unique production cost modeling for each scenario, the CTPC would rely on existing zonal production cost modeling runs from Duke's Carbon Plan Integrated Resource Plan (CPIRP). If CTPC does this, it will effectively be estimating the value of key benefits instead of using widely available and commonly used tools to calculate those benefits with reasonable accuracy. The CTPC should therefore perform nodal production cost modeling to iteratively test and refine the transmission expansion and calculate benefits for each scenario's final transmission portfolio.

In principle, we support the six proposed cost savings and other benefits that the CTPC proposes to include in its MVST benefits assessment. In addition, we believe the CTPC should reserve flexibility to (1) consider any additional relevant benefits of the identified solutions during the needs assessment and solution development phases (such as operational benefits of upgrades) and (2) include those benefits in the final portfolio assessment, at least qualitatively. By this request, we do not intend to increase the scope of the analysis that the CTPC conducts; we mean only to acknowledge that additional benefits could be identified during the study process and documented for consideration in the final report.

We also support the change to the draft study scope specifying that the CTPC will document its methodology for quantifying each benefit and review its methodology with the TAG stakeholders prior to the Solutions Meeting. We request that this methodology development and review process take place with sufficient time for the CTPC to receive and review written comments review them and implement any changes to the methodology based on the review process prior to the Solutions Meeting.

The importance of documenting and reviewing the methodology for quantifying each benefit was highlighted by a response to a question raised during the Assumptions Meeting, which concerned the CTPC's approach to the congestion and fuel savings benefit metric. CTPC representatives responded that they are planning to use a zonal production cost simulation model, similar to the model used in Duke's CPIRP modeling, for quantifying the congestion and fuel savings of MVST solutions. We are concerned that zonal production cost simulation models lack the necessary granularity to accurately reflect the operation of Duke's transmission system, the dispatch of the generation resources, and how both will change with the addition of the proposed transmission solutions. Zonal production cost models will only capture the impacts of upgrades between the zones defined by the CTPC, such that any solutions proposed within a zone will result in zero congestion and fuel savings benefits. In addition, zonal models tend not to accurately reflect the amount of available transfer capability between zones or the dynamics between flows across multiple zones that are captured in a nodal production cost simulation model.

To this end, we strongly recommend that the CTPC utilize a nodal production cost model of Duke's system reflecting the detailed topology of its system and the system's capacity-limiting contingency constraints. Nodal modeling is essential for calculating the full costs and benefits of new transmission elements and operations throughout the Duke system. The comparative imprecision of zonal modeling is one reason why all proactive economic or multi-driver transmission planning processes occurring across the U.S. (including MISO, SPP, ERCOT, CAISO, NYISO, and PJM) utilize a nodal production cost model to estimate production cost savings and other benefits of new upgrades, such as reduced emissions and reduced energy losses. In short, nodal modeling represents a widely used, well-supported, and prudent utility practice commensurate with the complex, multi-billion-dollar scale of investments to be evaluated in the CTPC's multi-value transmission studies.

While initial development of an accurate nodal production cost model of the Duke system (and its neighboring systems) will require an investment of time and resources, the model would thereafter be available for future local and regional transmission planning processes. Nodal modeling would also be available for other uses, such as estimating the relative value of solar and wind energy output at different locations on Duke's system during resource procurement processes and analyzing proposed resource mixes in long-term resource planning studies. Fortunately, the CTPC would not need to begin from scratch to develop a nodal production cost model. Developers of several production cost models, including Power System Optimizer (PSO), PROMOD, and PLEXOS, maintain nodal production cost model databases of the Eastern Interconnection that the CTPC could use as a starting point.

At least one vendor (Newton Energy Group, developer of PSO) has a recently updated 2024-Q2 model that allows selection of the footprint configuration the CTPC would desire built on top of three MMWG power flow cases (2023 vintage) for 2025, 2028, and 2033 to allow different power flow cases for future years supported by a weather dataset with wind, solar, load, and interchange profiles for the last 12 historical years. The CTPC could refine assumptions for Duke's system, including reviewing generation costs and technical performance and adding more detailed constraints on its system, to build a highly accurate model that could be updated on a rolling basis. The resultant model would have the capability to run a contingency analysis iteratively with commitment and dispatch at any decision cycle, as well as a full N-1 security analysis dynamically under changing system conditions such as evolving and optimized transmission topology.

Finally, we support the CTPC's proposal to consider all practical solutions to cost-effectively upgrade and operate the power system, including reconductoring and rebuilding existing facilities on existing rights of way, moving to higher voltages on existing corridors, building higher-voltage greenfield projects, dynamic line ratings (DLRs), storage as a transmission asset, topology control, simple Remedial Action Schemes (RAS), and power flow control devices (reactors, FACTS, phase shifters, etc.). As noted during the Assumptions Meeting, we recommend that CTPC review the planning guidelines that CAISO uses for defining simple RAS.[2] The CTPC should also incorporate significant network upgrades recently identified in interconnection studies to be required for interconnecting new resources as potential solutions in the MVST process.

However, without nodal production cost modeling, it will be very difficult for the CTPC to properly compare the cost-savings benefits created by these different types of solutions. As such, we strongly recommend that the CTPC implement a nodal production cost model during this and future MVST cycles. Developing and utilizing a nodal production cost model will align the CTPC with industry best practices for evaluating and identifying least-cost, proactive, multi-driver solutions to maintain a reliable and cost-effective transmission system over the long term.

[2] CAISO, California ISO Planning Standards, February 2, 2023.

2. Generation Modeling Assumptions

Rigid generation assumptions tied exclusively to Duke's CPIRP portfolios will prevent the MVST process from co-optimizing transmission and generation, which is key for creating the most cost-effective plan for ratepayers. To pursue true least-cost optimization, the CTPC should re-run Duke's capacity expansion model as necessary to consider generation assumptions that diverge from the CPIRP portfolios.

The proposed study scope does not take this approach. For example, multiple proposed scenarios sought to simulate a future in which small modular reactors are not economically available within the MVST study timeframe. These scenarios would identify the transmission needs created by the replacement clean energy resources that would be needed for Duke to nevertheless meet its decarbonization mandates under H.951. However, at the Assumptions Meeting, CTPC representatives stated that modifying the nuclear assumptions would not affect transmission needs because it would only postpone the retirement of existing emitting generation units. Likewise, while the proposed MVST scenarios will include an additional 2400 MW of offshore wind generation as a sensitivity, CTPC representatives stated that the model would be run using only redispatch. For the MVST process generally, rather than assessing alternative generation portfolios, CTPC representatives stated that the CTPC intends to keep the Integrated Resource Planning and transmission planning process separate.

Co-optimizing the generation and transmission buildout has been a cornerstone of the proactive, multi-value transmission planning methods successfully used by MISO and other grid operators, which seek to identify the transmission needs required to meet a range of future outcomes while maximizing benefits for consumers. It would also contradict the Commission's directive that Duke integrate transmission planning and resource planning to ensure system reliability and least-cost compliance with H.951.

Broadly, we support the proposed approach to measure the benefits of each scenario against a plausible base case without proactive planning through the MVST process. In the base case, transmission is primarily built based on reliability studies (using 2024 reliability study results to identify needed upgrades) and annual interconnection cluster studies. The cost savings under the proactively planned approach relative to the reactive base case approach will quantify the ratepayer benefits of a proactively planned transmission expansion.

With respect to the proposed scenarios. we support the CTPC's proposal in Scenarios 2 and 3 to evaluate alternative solar generating capacity deployment patterns based on the P3 Fall Base portfolio, using a base capacity distribution similar to the 2023 Public Policy Study in Scenario 2 and a high DEP capacity distribution in Scenario 3 as proposed by the PWG that shifts 2 – 3 GW of solar to DEP. We note that the proposed solar capacity distribution in the updated Study Scope for Scenario 3 Option – PWG Solar Shift is inconsistent between the 2034 Summer Cases (6.5 GW in DEC and 4.3 GW in DEP) and the 2034 Winter Cases (2.5 GW in DEC and 10.1 GW in DEP). We also recommend that the CTPC shift some battery storage capacity that is installed as solar plus storage from DEC to DEP in Scenario 3.

For setting the Scenario 2 capacity distribution, we propose that the CTPC and solar developers review in detail the county-level distribution of solar capacity shown on slide 16 of the Assumptions Meeting materials and incorporate new information since the development of the 2023 Public Policy study capacity distribution, including locations with high upgrade costs in that study, updated interconnection requests, and input from developers on attractive locations on the Duke system.

Finally, CCEBA requests that the CTPC add an additional scenario to evaluate a P3 Fall Base portfolio with 5.4 GW of solar connected as ERIS instead of NRIS to reflect a future with greater use of provisional service and/or ERIS. This exercise is essential to understanding full existing system capacity, all options for mitigation and improvement and their likely value. CCEBA disagrees with the rationale that Duke provided during the Assumptions Meeting for not including the ERIS study in the MVST Study Scope. Duke stated that the ERIS scenario should not be included because (1) Duke must consider both the energy and capacity needs of its system, (2) developers are not interested in ERIS, and (3) Duke is already providing provisional service for federal-jurisdictional interconnection requests and pursing provisional service for state-jurisdictional interconnection requests.

CCEBA provides responses to each of these reasons below:

1. Allowing new resources to interconnect as ERIS does not preclude Duke from considering both the energy and capacity needs of the system. New solar resources interconnecting as ERIS would provide significant energy value and may also provide non-zero capacity benefits to the system and does not require Duke to reduce any other capacity on its system that provides capacity value.

2. Solar developers that are members of CCEBA are interested in better understanding the impacts of ERIS on their projects and pursuing ERIS for new resources. Limited requests for ERIS have been submitted to date due to the requirement by Duke that solar resources procured through the CPRE and solar procurements must request NRIS. Solar developers have demonstrated their interest in ERIS-type service in other markets, including SPP, MISO, and ERCOT, where ERIS is an attractive alternative to NRIS.

3. Provisional service is an important interconnection service option for allowing new resources to start operations earlier without having to wait for the completion of all required network upgrades. However, provisional service is not a replacement for long-term ERIS service.

3. Planning Horizon

The CTPC should adopt a 20-year planning horizon that begins from the end of the current MVST planning cycle. For this cycle, that would encompass the 2044 Summer and 2044/45 Winter cases.

Maintaining the 10-year planning horizon will limit the feasibility of achieving or executing the identified transmission solutions needed to accommodate the CPIRP's generation portfolios, which go out to 2050. For example, Duke's 2022 Carbon Plan noted that developing greenfield transmission can require 10 to 15 years from the project start date. Such solutions would not be identified using the short time horizon the CTPC proposes, squandering valuable time for planning needed long-lead projects. This will result in the MVST process identifying small-scale upgrades that will cost ratepayers more in the aggregate than a smaller number of large-scale projects. A 10-year horizon could also result in short-term solutions that will be regretted or will even interfere with more cost-effective long-term solutions, such as by using up valuable rights-of-way with incremental upgrades that make it more challenging to deploy higher-capacity lines that will be needed 10 to 20 years from now.

A limited planning horizon does not provide clear additional value to the CTPC's existing reliability, economic, and public policy transmission planning processes, all of which currently utilize a 10-year planning horizon. Combined with the CTPC's resistance to model new generation not included in a CPIRP portfolio, a 10-year planning horizon does not allow the CTPC to proactively plan for future conditions.

Additionally, the use of a 20-year planning horizon matches the requirements of the Federal Energy Regulatory Commission's Order No. 1920, which governs regional transmission planning. The CTPC referenced the Notice of Proposed Rulemaking that preceded Order No. 1920 as the model for the MVST process. Once Order No. 1920 is implemented at the regional level, the MVST will serve as a local input to the corresponding regional Long-Term Regional Transmission Planning process completed by the Southeastern Regional Transmission Planning (SERTP) group. Utilizing a 20-year planning horizon in the MVST will minimize friction with that process.

We are sympathetic that this is the CTPC's first attempt at proactive, multi-value transmission planning and recognize that there will be growing pains. However, a 20-year planning horizon will become commonplace with the implementation of Order No. 1920, and it would benefit the CTPC to start building experience with a time horizon of that length while it still has time. And, as noted above, failure to do so now will set long-lead solutions back even further.

If the CTPC sees additional value in conducting a 10-year study, it can include an interim analysis of the generation and transmission build in 10 years, using the 2034 Summer and 2034/35 Winter cases. However, it is imperative that the MVST look beyond this timeframe to maximize the cost savings and reliability benefits of proactive planning and ensure interim solutions do not interfere with longer-term solutions.

We hope these comments will be helpful.

Sincerely,

John D. Burns
General Counsel
CCEBA

/s/ Karly Lohan
Karly Lohan
Program Manager
Southeastern Wind Coalition
karlyl@sewind.org

/s/ Nicholas Guidi
Nicholas Guidi
Senior Attorney
Southern Environmental Law Center
nguidi@selcdc.org

/s/ Maggie Shober
Maggie Shober
Research Director
Southern Alliance for Clean Energy
maggie@cleanenergy.org

/s/ David Rogers
David Rogers
Deputy Director, Beyond Coal
Sierra Club
David.Rogers@sierraclub.org

/s/Justin Somelofske
Justin Somelofske
Regulatory Counsel
North Carolina Sustainable Energy Association
justin@energync.org